NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

METHODOLOGY FOR THE DETERMINATION OF TARIFFS AND PRICES IN THE ELECTRICITY INDUSTRY

CONSULTATION PAPER

June 2022

List of figures:

Abbreviations and Acronyms

ABC	Activity Based Cost
β	Beta
CAPM	Capital Asset Pricing Model
CECA	Capital Expenditure Clearing Account
CoS	Cost of Supply
CPI	Consumer Price Index
CTS	Cost to Serve
DMP	Demand Market Participation
DMRE	Department of Mineral Resources and Energy
DRC	Depreciated Replacement Cost
DSLI	Distribution Supply Loss Index
dÞ	Debt Premium
E	Expenses
EPP	The South African Electricity Pricing Policy
ERTSA	Eskom Retail Tariff Structural Adjustments.
GWh	Giga Watt hours
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ITSMO	Independent Transmission System and Market Operator
JSE ALSI	Johannesburg Stock Exchange All Share Index
Kd	Cost of debt
Ke	Cost of equity
LRMC	Long Run Marginal Cost
M&V	Measurement and Verification
MEAV	Modern Equivalent Asset Value
MRP	Market Risk Premium
MTSAO	Medium-Term System Adequacy Outlook
MWh	Mega Watt hours
MYPD	Multi-Year Price Determination
NERA	National Energy Regulator Act, No. 40 of 2004
NERSA	National Energy Regulator of South Africa
O&M	Operating and Maintenance
OCGT	Open Cycle Gas Turbine
PBR	Performance Based Regulation
PPA	Power Purchase Agreement
RAV	Revaluation Asset Value
RCA	Regulatory Clearing Account
SSEG	Small Scale Embedded generators
TD	Tariff Design
TNC	Transmission and Network costs
TOC	Trended Original Cost
UCT	Unit Capability Factor
WACC	Weighted Average Cost of Capital
WEPS	Wholesale Electricity Pricing System

Keywords

Activity - Based Costing
Benchmarking
Capital Expenditure
Data comparisons
Electricity Price Determination Methodology
Independent System Operator
Installed capacity
Load
Load profile
Load Profile
Marginal Price
Merit Order Dispatch
Operational capacity
Operational Expenditure
Prices
Tariff methodologies
Tariff Structures
Tariffs
Type of Use
Unbundling
Weighted Average Tariff

Definitions

Account	The invoice received by a customer for a single POD/point of supply or if consolidated, multiple points of delivery/supply for electricity supplied and/or use of the System
Active energy charge or energy charge	The charge for each unit of energy consumed, typically charged for as c/kWh.
Activity-Based Costing (ABC)	Activity-Based Costing (ABC) is as an approach to the costing and monitoring of activities, which involves tracing resource consumption and costing final outputs. Resources are assigned to activities and activities to cost objects. The latter use cost drivers to attach activity costs to outputs. For example, the tariff is a function of assigning actual costs to each activity (service) along a value chain, such as generation, transmission and distribution.
Administration charge	The daily fixed charge payable per POD/point of supply/service agreement to recover administration-related costs such as meter reading, billing and meter capital. It is based on the monthly utilised capacity or monthly maximum exported capacity per POD/point of supply/service agreement.
Affordability subsidy charge	The transparent charge indicating socio-economic subsidies related to the supply of electricity to residential tariffs and is payable on licensees related active energy sales to non-local authority tariffs.
Ancillary Service charge	The charge that recovers the cost of providing ancillary services by the Independent System Operator
Code	The Distribution Code, the South African Grid Code, the Grid Connection Code for Renewable Power Plants or any other code, published by NERSA, as applicable, and as amended, modified, extended, replaced or re-enacted from time to time.
Consumer groups	Consumer groups will reflect clusters of consumers that share similar load profiles and therefore may be used as a proxy for consumers that do not have smart metering for the purposes of determining the cost-to-serve and subsequent tariffs for the such consumer groups.
Consumption	Consumption is the total electricity consumed in a given period and generally expressed in MWh.
Demand	Demand is the rate at which electricity is consumed, generally in MWh, and informs the capacity required to meet demand at any point in time.
Distribution	The regulated business unit through which the distribution licensee constructs, owns, operates and maintains the Distribution System in accordance with its licence and the Code.
Distribution connected	Means connected to the Distribution system.

Distribution losses charge	means the production-based (energy) incentive to generators. The losses charge is based on the approved loss factors, the load factor, the amount of energy produced seasonally and TOU and the WEPS energy rate (excluding losses).
Distribution network capacity charge	(Previously known as the Distribution network access charge) means the R/kVA or R/POD fixed network charge raised to recover Distribution network costs and depending on the tariff is charged on the annual utilised capacity or maximum export capacity where maximum demand is measured or the NMD where maximum demand is not measured. The charge will also include costs associated with technical losses.
Economic cost	Economic cost is the combination of losses of any goods that have a value attached to them by any one individual. Economic cost is used mainly by economists as means to compare the prudence of one course of action with that of another.
Load (electrical circuit)	An electrical load is simply any component of a circuit that consumes power or energy and converts electrical energy into light, heat, or useful motion, which constitutes a load on the circuit.
Load (electricity system)	This is the demand expressed as the MW that a consumer brings to the electricity system as a result of the various loads consuming energy and needs to be balanced by the Independent System Operator at any point in time.
Load Type	Load categorised as Load 1, Load 2, Load 3 and Load 4, for the purposes of this consultation paper.
Merit Order Dispatch	The purpose of the merit order was to enable the lowest net cost electricity to be dispatched first thus minimising overall electricity system costs to consumers.
Price	In terms of the Act, “price” means a charge for electricity but for the purposes of this document, “price” means the charge for electricity to a customer or consumer that can be one-part or multi-part, which is a culmination of summing of all relevant tariffs of services consumed by a consumer or customer.
Price Stability	In terms of this document, price stability means prices that are based on predictable methodology that yield predicable prices in the long term that facilitate investments by both the electricity supply industry as well as electricity consumers. Price stability facilitates affordability of electricity and competitiveness of industries. Price stability does not mean a fixed, low price, but prices that are predictable and cost-reflective.
Prosumer	Prosumers are generally defined as electricity consumers that produce part of their electricity. needs from their own power plant and use the distribution network to inject excess production. and to withdraw electricity when self-production is not sufficient to meet own needs.

Stable prices	Price stability is a function of predictability, affordability, competitiveness related to the price level (the tariff) and its change over time (price path).
Tariff	In terms of the Act, “tariff” means a charge for electricity but for the purposes of this document, “tariff” means the charge for a service and activity that is reflective of the costs incurred by a service provider that can be one-part or multi part.
Tariff Setting Methodology	The methodology is the detailed set of steps and modelling required to apply the principles to actually set the tariffs, including the types of data that will be analysed and the format that must be applied, benchmarks that must be used and indices that will be used (eg. CPI). The methodology is based on the conventional economic regulation methodology that is premised on providing regulated entities an opportunity to recover prudent costs and make a reasonable return on assets using a revenue requirement methodology without providing a guarantee.
The Act	In the context of this document, refers to the Electricity Regulation 2006, (Act No. 4 of 2006).
Trading	Trading refers to purchasing and selling power between participants in the energy industry. Various forms of trading are possible depending on the market design, ranging from short-term trading to long-term power purchase agreements. Trading may include buying, selling of physical commodity to buying, and selling financial instruments and derivatives based on the physical asset. Trading may include buying, selling of physical commodity to buying, and selling financial instruments and derivatives based on the physical asset.
Unbundling	Depending on the context, refers to either physical or financial separation of regulatory activities or their associated costs.
Utility	An electric utility is a company in the electricity industry (often a public utility) that engages in electricity generation and distribution of electricity for sale, generally in a regulated market.
Weighted Average Tariff	The tariff that represents the proportion of power dispatched at the related tariff that takes account of the relative amount of power supplied by each generator and for the purposes of this paper, is the suggested proxy for a marginal price in the absence of a functioning/competitive market.

1. Introduction

1.1. Electricity Industry (EI) in South Africa is facing profound changes that require concomitant changes to the regulatory approach, as empowered by legislation. To enable these changes, the pricing methodology needs to be overhauled to align the foundation of the pricing approach to the changes in the industry. The overhaul also needs to consider the fundamental paradigm shift towards a more consumer-focused approach that balances the needs and drivers of demand to ensure rational and sustainable supply side investments and goes to the heart of the role of an economic regulator.

1.2. Implementing a more balance customer focused approach may seem profound or even counter intuitive after one and a half decades of MYPDM, however, it is an overdue correction in the role of the Regulator in stabilising the electricity industry. The Essential Services Commission (ESC), the Victoria State Regulator, observed that "Independent economic regulation is a powerful tool in policy-makers tool kit in **promoting the long terms interests of consumers**. It does so by creating incentives — rather than directives — for service providers to engage fairly with customers and to operate their businesses efficiently."

1.3. Sections 14 (1) (d) and 14 (1) (e) of the Electricity Regulation 2006,(Act No 4 of 2006) (the "Act") empowers the Energy Regulator to *make any licence subject to conditions relating to the setting and approval of prices, charges, rates and tariffs charged by licensees and the methodology to be used in the determination of rates and tariffs*. Section 15(1) of Act subsequently prescribes the principles that must govern the licence condition determined under section 14 relating to the setting or approval of prices, charges and tariffs.

1.4. However, Section 14(1) (g) also empowers the Energy Regulator to impose a condition of the licence relating to *the regulation of the revenues of licensees,* which interpretation, when read with the latter part of the section 15(1) that makes reference to *the regulation of revenues*, has resulted in the mixing of the terms of "allowed revenue" and "regulating revenue." In regulatory terms "allowed revenue" or "revenue requirement" is **not** a promise but an opportunity to earn the revenue while revenue regulation implies an expressed promise to provide the estimated revenues to a licensee.

1.5. The unbundling of the electricity supply industry and the introduction of private market participants have imposed a need to change the pricing methodology to enable greater transparency, efficiency, cost reflectivity and recognition that the services might be provided by different participants who need to have clear tariffs to compensate them for their costs. While an attempt to regulate revenues may have had merit when the supply industry was largely dominated by a single player or a single buyer, Eskom, it is impossible to make that promise to a fragmented industry.

1.6. Notwithstanding the correctness, or not, of regulating revenues, the approach has resulted in an untenable situation. Where the utility was losing sales (translating into reduced revenues), the regulator would be forced to increase prices to try to give the “promised revenues”. Unfortunately, increasing the prices results in further loss of sales, which forced price increases, resulting in a situation that is known as the “utility death spiral – discussed further in paragraph 2.8.”

1.7. The following summarises the key drivers for change, with the details provided in Section 2 below:

1.7.1. Recent draft amendments to the Electricity Pricing Policy and the Electricity Regulation Act signalled a profound departure from the regulation of prices and tariffs, including the abandonment of the revenue regulation and single buyer models, as well as unbundled tariffs across the value chain.

1.7.2. There is a clear intention from government, and also signalled in the EPP and the Act’s draft amendments, to reform electricity market structure as well as the amendment of legal framework to facilitate the same – refer to **Annexure B** for further commentary on market structure.

1.7.3. Eskom is being unbundled into three separate entities namely, generation, transmission and distribution.

1.7.4. Increased penetration of renewable energy independent power producers (IPPs), heralding:

1.7.4.1. Increased level of self-generation and embedded generation.

1.7.4.2. Greater requirement for bilateral contracts.

1.8. To address these changes and challenges in the electricity industry, the Energy Regulator is implementing the strategic initiative to develop the new Electricity Price Determination Methodology, in pursuit of the strategic objective of **improving systems and tools** to **strengthen organisational capacity**. In addition, a number of strategic initiatives will be executed to provide synergy with each other to build a more robust and agile NERSA that can adapt to the transformation being witnessed in the Electricity Industry.

1.9. NERSA embarked on a rigorous review of the Electricity Pricing Framework and seeks to implement changes to the Electricity Priced Determination Methodology. The document detailing the principles that will underpin the new approach has been consulted on, and the comparison of the MYPD4 (old principles) and the MYPDM (new principles) and the narrative of the changes can be found in **Annexure C**.

1.10. The current process is a next step aimed at seeking and detailing stakeholder input on the proposed consultation paper with a view of finalising new Electricity Price Determination Methodology by the 30 September 2022.

2. Drivers for change to the Electricity Price Determination Methodology

2.1. Globally, electricity supply industries are forced to respond to a wide range of economic, environmental, strategic, structural, organisational, technological and other challenges. These are increasingly disruptive to electricity utilities worldwide and also to the cost structure, price control methodologies, tariffs, tariff setting process and revenue stability of electricity licensees in South Africa.

2.2. Figure 2-1 below provides an indication of some of these drivers for change that have been considered in developing the business case for the overhaul of the Electricity Pricing Framework. The purpose of this review and the updated methodology is to **improve** the regulatory **tools** and **strengthen** the Regulator's **capacity** to fulfil its mandate to **stabilise prices** in an effort to reign in the current electricity crisis.

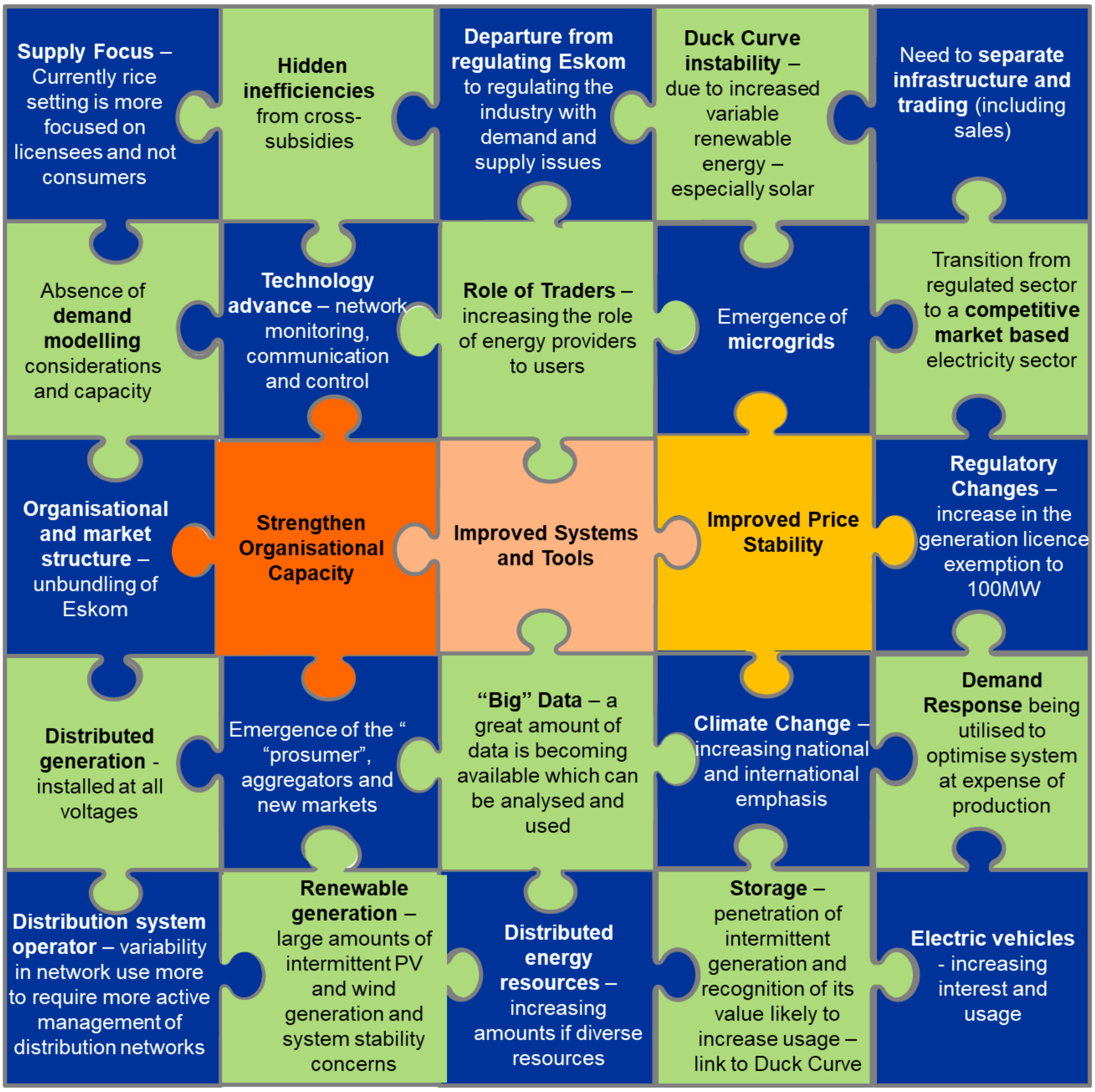

Figure 1: Key drivers for change in the SA Electricity Industry

2.3. In South Africa, these challenges are linked to increasing and sustained concerns regarding **escalating electricity prices**. Alongside electricity price concerns, poor performance by the industry particularly the quality of supply, is driving a crisis where regular load shedding and outages being the consistent feature of everyday life, with Eskom plant availability languishing at 60% for 2021/22. The electricity industry crisis is having a substantial impact on the country's economy, constraining growth and development compounding the difficulty in attracting investment. These challenging issues are driving **the need for significant reform** in the industry and regulatory approach to electricity price control.

2.4. Reform is needed to provide a more consistent and over-arching regulatory framework that can drive improved industry performance through both competition and regulatory incentives, help to control costs and prices, and encourage necessary investment throughout the value chain. Some of the highlights of these drivers, or business case, for change, are outlined below.

2.5. **Previous Stakeholders' comments on electricity pricing principles:** Stakeholders comments during the public consultation process highlighted the following:

2.5.1. Current Price Instability: All stakeholders commented on the negative impacts of the continued price instability. Most commented that foundational sections of the Multi-Year Price Determination Methodology (MYPD4) did not adequately address the intended objectives, and more specifically providing price stability. Business associations consulted, indicated that regulation of revenue, as applied to the conventional revenue-based methodology, has not delivered the intended predictability of the MYPDM over the long term. However, there were a number of postulations as to how to address the price instability, which was largely driven by the optics of the stakeholder.[1]

2.5.2. ABC (Activity based costing approach): During the consultation process all but one stakeholder indicated that the approach will increase transparency in costs determination however its implementation may require more time and increased levels of prudency verification. Other stakeholders indicated that the approach may be difficult to understand and implement – only one stakeholder indicated that it should not be applied to the natural monopoly parts of the value chain (Tx and Dx) as averaging was more fair to consumers.

2.6. **Policy shifts spurring the industry towards deregulation**: Further to these stakeholder concerns, a number of policy shifts and related regulatory signals will impact the future of price regulation. They point to the urgent need to overhaul the pricing methodology, amongst other elements of the regulatory framework,

[1] Only the incumbent and dominant player, Eskom, felt the regulation of revenue should be maintained, most stakeholders commented that stable prices and price path, using a metric other than revenue/ sales, would be better. In most other jurisdictions, regulators conventionally apply CPIX calculations to set the price path.

namely:

2.6.1. Eskom would be unbundled, structurally transforming the electricity industry

2.6.1.1. phasing out the single buyer modality, replacing it with an Independent System Operator and

2.6.1.2. potential increase in bilateral contracts.

2.6.2. the threshold for unlicensed registration of generators increased up to 100MW coupled with

2.6.2.1. bilateral contracting and eased access to the grid

2.6.2.2. stable and transparent wheeling tariffs,

2.6.3. Draft amendments to the Electricity Pricing Policy (EPP) and the Electricity Regulation Act, 2006 include:

2.6.3.1. the abandonment of regulation of revenue,

2.6.3.2. the establishment of an Independent System Operator

2.6.3.3. the design of unbundled tariffs, such as the unbundled Use of System charges envisaged in the EPP.

2.7. **Regulation must play a vital and enduring role** in industry development Regulatory price controls will be a consistent feature for for those parts of the electricity value chain, which are "natural" monopolies, such as the transmission and distribution networks[2], regulatory price controls will be a consistent feature of the regulatory landscape. Even beyond deregulation, as it is the case in other jurisdictions, ongoing regulatory oversight and supervision will be required to ensure that customer's interests are protected. The form, manner and associated regulatory may change but the need for regulatory oversight of this networked industry will always remain.

2.8. **Rising Prices, Falling Sales – Utility Death Spiral?** The MYPD methodology is based on two fundamental elements:

2.8.1. Regulating Eskom Revenues, thereby 'guaranteeing' Eskom its revenue, providing little incentive to Eskom to improve efficiencies and sales

2.8.2. Determining the average price by dividing the allowed revenue, largely determined by generator's declared costs, with the forecasted sales

2.9. **Setting cost reflective municipal tariffs**: Currently NERSA approves municipal

[2] The emergence of micro-grids and "islanding" which seem to be inevitable going forward is raising questions around distribution being seen as a natural monopoly. The need for limiting multiple wires crisscrossing each other and limiting provision of wires to one provider in an area needs to be fully explored and discussed.

tariffs based on a percentage guideline increase and municipal tariff "benchmarks". The municipal tariff guideline increase is developed based on Eskom's approved bulk price increase of electricity to municipalities and the increase in the municipalities' cost structures. This will be determined at a trading level of the electricity value chain where consumer prices will be set based on summing generation, transmission, distribution, trading and other pass through costs. Added to these costs, municipalities would also implement itemised surcharges approved by their council based on the Municipal Systems Act, 2000 (Act No.32 0f 2000), section 74, 2(f).

2.10. **Changes to the broader enabling environment**: The aforementioned overhaul of the Electricity Price Determination Methodology, will elucidate areas/regulatory processes that may need proactive interventions, such as:

2.10.1. Formalisation of the data provision in the form of rules that will govern the type of data and its format, but supported by the concomitant security protocols to ensure confidentiality and data privacy is preserved;

2.10.2. New skills sets, or at least upskilling of those who will engage with the EPDM at an operational level;

2.10.3. Changes to rules and codes that ensure stability and safety of the electricity system.

2.11. Further explanation on these drivers is attached as **Annexure D**.

Stakeholder Question 1

a) The methodology seeks to uncover all licensees' costs within the ESI, including municipalities. Stakeholders are requested to comment on the move from an approach based on approving municipal tariffs to one that sets municipal tariffs based on unbundled costs as proposed by the methodology.

3. Legal basis for the development of the methodology

3.1. The development of the methodology is a process positioned on achieving fair evaluation, efficient and effective administrative process and rationality from a marsh of information. The general nature of the powers mandated to NERSA by section 4 of the Electricity Regulation Act, 2006 shall, without related regulatory instruments, result in abstract and arbitrary conclusions.

3.2. Because the methodology is a regulatory instrument aimed at achieving what has been alluded to in clause 4.1 above, the methodology does not have the status of an Act, rule, regulation or binding effect to courts. The methodology derives its binding effect when applied to a particular set of information where it is dedicated to. In the instance of tariff approval and revenue regulation, the methodology sets out the compliance requirements and related evaluation mechanism. This set of requisites cannot be abandoned arbitrarily or not be complied with as this may the application or the decision defective.

3.3. Section 15 of the Act does not empower NERSA to develop the methodology but its anchored on the licence conditions precedent. What the Act further provides in section 15 is that, such a condition must not be prohibitive in nature or application from achieving what is in Section 15(1)(a-e) otherwise there is invalidity to its enforcement.

3.4. It should also be emphasised that, the section does not deprive NERSA the powers to exercise its powers to ensure that the objects of the Act are sustained as well. This view has found support in Judge Kollapen ratio decidendi in the Eskom matter in that, the powers of NERSA cannot be constrained by the provisions of section 15(1) if the outcome can be unreasonable and a burden to the customers and economy.

3.5. Where do we derive the powers to develop the methodology? The Act has given us the discretionary powers to issue licence conditions. Being alive to the fact that our decisions are administrative action and that they must be made through a process, a condition was issued to Eskom and Clause 6.2 of Eskom's distribution licence carries a condition referencing the usage of a methodology to determine prices, charges and tariffs. The powers to determine such condition is derived from section 14(1) I of the Act. Having issued such a condition, NERSA is therefore bound to have a methodology in place to determine prices, charges and tariffs for Eskom otherwise the decision will become unlawful and irrational.

3.6. Section 14, 15 and case law have been purposefully looked at to ensure effective and efficient administration of the approval tariffs, prices and charges. This consideration has been made to ensure that, the process is not seen as generating new powers to NERSA but a recognition of discretionary powers resident in the Act and appropriate exercise of it. The scope of the methodology is only broad in as far as process, information need, identification of the information, assessment of the information, principles to be involved and decision making on tariff, prices and charges.

4. Introduction to principles

4.1. The detailed work on the pricing principles is documented in the Consultation Paper published by NERSA on the 24th of September 2021 with the subsequently approved decision published on the NERSA website on the 12 January 2022. Principle 1 is based on the unbundling of the electricity value chain (supply side); Principle 2 deals with understanding the consumer needs and related load profiles (demand side) and Principle 3 deals with setting cost reflective consumer prices.

4.2. It is important to note that although the three principles are independent and refer to different aspects of electricity pricing, they are related and supportive of each other. Consumer prices derived using principle 3, use tariffs derived using principle 1, to produce a built-up consumer price reflecting the various load tariffs and the other tariffs/levies/surcharges for services rendered. These are allocated to the various loads by customer, as understood through principle 2 - thus reflecting the economic cost of consumption.

4.3. Legal foundation for the revisions to the Electricity Pricing Methodology:

4.3.1. **Principle 1** is about unbundling of the electricity value chain, and is aimed primarily, at giving effect to section 15 (1) (a) which requires that tariffs "*must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return*". This principle is primarily supportive of the achievement of the following objects of the Act:

4.3.1.1. achieving "the efficient, effective, sustainable and orderly development and operation of electricity supply infrastructure in South Africa";

4.3.1.2. facilitating "investment in the electricity supply industry"; and

4.3.1.3. promoting "the use of diverse energy sources and energy efficiency".

4.3.2. **Principle 2** is primarily about giving effect to section 15 (1)(c), which requires that tariffs "*must give end users proper information regarding the costs that their consumption imposes on the licensee's business*." This principle also allows the licensees to understand the role played by electricity in lives of consumers. This principle has facilitated inclusion of demand concerns in the electricity pricing framework. It is primarily supporting the following objects of the Act:

4.3.2.1. ensuring "that the interests and needs of present and future electricity customers and end users are safeguarded and met, having regard to the governance, efficiency, effectiveness and long-term sustainability of the electricity supply industry within the broader context of economic energy regulation in the Republic;

4.3.2.2. facilitating investment in the electricity industry[3]*;* and

4.3.2.3. promote competitiveness and customer and end user choice."

4.3.3. **Principle 3** addresses the legal requirements espoused in sections 15(1)(b) and (d) of the Act while primarily seeking to, where possible, deal with cross subsidies. Through Principle 3, the pricing framework seeks to ensure that the consumer prices "*provide for or prescribe incentives for continued improvement of the technical and economic efficiency with which services are to be provided;* and *avoid undue discrimination between customer categories."* This principle supports the following objects act:

4.3.3.1. achieving "the efficient, effective, sustainable and orderly development and operation of electricity supply infrastructure in South Africa";

4.3.3.2. ensuring "that the interests and needs of present and future electricity customers and end users are safeguarded and met, having regard to the governance, efficiency, effectiveness and long-term sustainability of the electricity supply industry within the broader context of economic energy regulation in the Republic";

4.3.3.3. facilitating "universal access to electricity";

4.3.3.4. promoting "the use of diverse energy sources and energy efficiency";

4.3.3.5. promoting "competitiveness and customer and end user choice"; and

4.3.3.6. facilitating "a fair balance between the interests of customers and end users, licensees, investors in the electricity supply industry and the public".

4.3.4. Techno-economic foundation for the revised pricing principles:

4.3.4.1. Principle 1 will allocate the efficient/prudent costs to produce/transmit energy and earn a reasonable return, and provide each activity in the value chain with a cost-reflective tariff;

4.3.4.2. Principle 2 seeks to understand the customers' needs in order to determine how they use electricity and the impact this has on

[3] An industry is characterised by both its suppliers and its consumers and proper understanding of customer & markets needs is essential for sustained investment in the industry. The supply industry cannot be sustainable without a corresponding sustainable demand sector.

electricity system and the subsequent economic cost of their consumption; and

4.3.4.3. Principle 3 seeks to reflect all costs associated with the delivering power to customers in the consumer prices for each load type by adding up the various tariffs attributable to the relevant activities (Principle 1) required to deliver the power to meet the specific loads (which are a function of the customer needs - Principle 2). However, there are a number of anomalies that need to be addressed with Principle 3, namely:

4.3.4.3.1. how to deal with the contractual obligations emanating from power purchase agreements (PPAs) from the past, present and future IPP bid windows because if principles of merit order dispatch are observed, certain IPPs, especially from earlier bid windows will not necessarily be dispatched;

4.3.4.3.2. how to deal with loads shifting from one period to another period as a positive behavioural change incentivised by the pricing signals; and

4.3.4.3.3. the fact that without a functioning market, the marginal price for setting generation tariffs will be a challenge and hence some form of weighted average tariff for the different types of generation plants dispatched to meet the associated loads will need to be considered.

4.4. Principle 1: Supply-Side - Unbundling Value Chain Activities with Tariffs

4.4.1. This principle involves unbundling the electricity value chain both ‘vertically’ and ‘horizontally’ into its constituent activities and costs associated therewith for each part of the electricity value chain identified and allocated accordingly and subsequently translated into the cost reflective tariffs for each activity. This principle has previously been loosely referred to as “*Activity Based Costing*”

4.4.2. Horizontal unbundling allows for the determination of normally “hidden costs” such as those associated with the provision of “ancillary services.” There are two activities that stand out in this regards, namely generation and ancillary services. Distribution, because of a number of distributors could also, in further, be analysed in the same manner.

4.4.3. Unbundling, applicable to both vertical and horizontal unbundling, involves the following activities:

4.4.3.1. Identification of different sub-activities at an appropriate level in each part of the electricity value chain. In the case of generation for instance, the appropriate level could be a generation plant level rather than a unit level;

4.4.3.2. Identification of relevant regulatory cost “buckets” of costs/cost types associated with different sub-activities and/or types of activities (at an appropriate granularity level) but not beyond power station level for generation.

4.4.3.3. Translation of these regulatory costs into individual tariffs for each unbundled items.

4.4.4. The purpose of Principle 1 is to set the unbundled tariffs for the supply side that will then be used as the cost basis for setting consumer prices with Principle 3.

4.5. **Principle 2: Demand-Side – Understanding consumer needs**

4.5.1. Principle 2 recognises that electricity consumers/customers have different the needs and that their demand profiles[4] are different, which impacts on what type of electricity generation plants need to be dispatched and when. In the case of self-dispatching power plants, some of the customer needs coincides with the production and others do not. In addition, customers have different load profiles, which may consist of various types of load in fluctuating proportions, driven by what the power is used for[5]. Different loads attract different costs to supply (informed by Principle 1) that are then translated into electricity prices with Principle 3.

4.5.2. The point of departure from the orthodox *cost-to-serve* studies to the approach being envisaged by Principle 2 is that the costs are not necessarily associated with a customer type, but with types of load. There is a greater degree of rationality and fairness in calculating the economic cost a particular load imposes on the grid as a foundation for electricity pricing. This recognises that the driver of electricity demand and the subsequent cost of consumption, is in fact the source of the load – refer to “Load” under Definitions. As discussed under section 8, this means that different customers can bring various types of load to the system, and may subsequently exhibit an accumulation of different load types at any point in time.

4.5.3. The key consideration for Principle 2 is defining the loads and their

[4] Most electricity planning does not consider demand profiling and simply looks at demand at aggregate level, hence concluding that non-dispatchable power sources can follow loads. Principle 2 is predicated on the recognition that certain load types can only be met through certain types of electricity generation options.

[5] It is common cause that the current electricity industry supply shortages are primarily linked to evening peak demand.

characteristics as they relate to the activities the end-user engages in, and the necessary predictably in terms of Quality, Price and Reliability of the power as appropriate, are namely:

4.5.3.1. constant demand – Load 1 (sometimes referred to as baseload)

4.5.3.2. semi constant demand – Load 2 (sometimes referred to as mid-merit)

4.5.3.3. short but intense demand – Load 3 (mostly referred to peak load)

4.5.3.4. ad-hoc and emergency demand – Load 4

4.5.4. Informed by the departure in paragraph 4.5.2 above, Principle 2 can be split into 2 subcomponents, namely:-

4.5.4.1. <u>The role of electricity in the consumer activities</u>: Understanding of what consumers use electricity for and how they use it. This enables NERSA to anticipate the impact of electricity prices on consumers in terms of affordability, profitability and competitiveness. This allows for a greater understanding of how these affect the sustainability of the respective consumer groups. This principle requires NERSA to fully understand the consumer decision making frameworks when it comes to their electricity consumption. The Regulator will be enabled to fully consider consumer inputs in its decision-making processes in respect of electricity price making. For NERSA to incorporate consumer inputs, however, it will require detailed consumer costs associated with energy consumption; and

4.5.4.2. <u>Consumer Load Profiles</u>: Informed by the understanding of the role of electricity, consumption can be monitored to determine consumer load profiles and the constituent loads that make up the load profile, over time. With accurate metering, load profiles can be monitored and anticipated resulting in unbundled loads - Load 1, Load 2, Load 3 and Load 4 - which are priced differently based on the underlying economic costs of the consumption, as metered and billed accordingly. The critical aspect of the application of Principle 2 is that consumers use energy for very specific activities. They also use the energy at different times of the day and for different durations. These aspects that are critical in understanding why a load profile looks the way it does and the implications for the consumer of how they manage their various load types within the load profile and how load types are priced.

4.5.5. The key theoretical principles underpinning the differential load approach are as follows:

4.5.5.1. **The economic principle of fungibility**: This allows one to measure the demand for and supply of electrons regardless of where they are in the system. This is a conventional economic concept for measuring and allocating use of interchangeable goods or services. By applying the theory of fungibility[6,7] of electricity, a specific load can be linked to the supply side with appropriate equipment to most cost-effectively supply the load.

4.5.5.2. **The technical principle of differentiated loads**. This is where different loads require different services (e.g. quantity and quality). It must be noted that different generation technologies and that different generation technologies have different associated economies of scale and costs. Furthermore, different services have different costs associated with each additional activity along the value chain e.g. transmission, system/market operation, distribution and trading etc.

4.6. Principle 3: Setting Cost-Reflective Consumer Prices

4.6.1. Principle 3 has previously been loosely captured as "*marginal pricing principle*" in recognition of how a functioning electricity market would 'discover' prices. Further analysis has refined the principle to incorporate regulatory approaches that could be adopted for the determination of consumer prices ahead of the market or in preparation of the electricity market.

4.6.2. The following guidelines should be followed when setting consumer prices. Before the market is fully functional, the Regulator will continue regulate and set cost-reflective consumer prices based on:

4.6.2.1. full recovery of all costs associated with the delivery of services to a consumer group;

4.6.2.2. generators dispatched on a "merit order"[8] dispatch;

4.6.2.3. the generation costs in the consumer prices determined on a Weighted Average Cost (WAC) basis for each load type; and

4.6.2.4. regular price assessments – which could be quarterly or monthly and reflected in arrears.

4.6.3. The approach to setting of consumer prices seeks to outline how the

[6] Fungibility is the ability of a good or asset to be interchanged with other individual goods or assets of the same type. Fungible assets simplify the exchange and trade processes, as fungibility implies equal value between the assets, such as electrons in an electricity grid, or the same grades of petrol from different sources in the same tank.

[7] It is on the principle of fungibility that wheeling is predicated.

[8] The purpose of the merit order was to enable the lowest net cost electricity to be dispatched first thus minimising overall electricity system costs to consumers.

system is planned and the market operated in order to respond to step changes in energy demand and how this translates into appropriate consumer prices. The following steps will be applicable before, during and after introduction of the electricity market:

4.6.3.1. For a given step change in energy demanded by the various types of loads identified in Principle 2, the power will be dispatched on a merit order[9] system based on the least cost generators – ie. those with the lowest tariffs from Principle 1.

4.6.3.2. The quantity of the power dispatched to meet the various loads on the system will be monitored and reported by the Independent System Operator – capturing which generator supplied what amount of power and record the duration of supply.

4.6.3.3. The different loads that come onto the system and the associated cost of power dispatched to meet various loads will effect a corresponding change in the price of electricity for that type of load and will form the basis for setting consumer prices[10] by NERSA.

4.6.4. Prior to the envisaged fully functioning electricity market coming into effect and effectively used for consumer price discovery, weighted average generation costs tariffs for each load based on the cost of the power dispatched by the Systems Operator will be used to determine customer prices.

4.6.5. Fundamental in this approach is that not only are the power plants dispatched on merit order but only those plants that are dispatched will be included in the resultant consumer prices determination. In essence,

4.6.5.1. qualifying generators with a set tariff will be dispatched; and

4.6.5.2. electricity prices will reflect the true economic cost of consumption; and

4.6.5.3. consumers will only pay for the services they will be enjoying.

4.6.6. The rationality and fairness of the intended approach are that prices signal the economic cost of consumption. In the absence of a competitive market, regulated prices seek to mimic the competitive market responses as a foundation for cost-reflective consumer prices.[11]

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[9] Merit order dispatching is a fundamental backbone for promotion of fairness in the dispatch of power especially when there is private sector participation.

[10] Discovery of consumer prices, in respect of day ahead prices, balancing prices and risk mitigation costs when the market is fully operational will be the responsibility of the Market Operator using market instruments.

[11] The economist and philosopher Adam Smith referred to the self-coordinating power of competitive markets as an 'invisible hand'. Contemporary economic regulation is less about correcting for market

5. Key Elements of the Underlying Revenue Requirement Methodology

5.1. The Revenue Requirement Methodology will continue to underpin the tariff setting mechanism as the conventional worldwide acceptable methodology for economic regulation of tariffs.

5.2. The revenue requirement (RR) is defined by the following formula:

$$\textit{Revenue Requirement} = \textit{Operating Expenses} + (\textit{Rate Base} * \textit{Rate of Return})$$

5.3. Although different jurisdictions may have different methods to estimate the revenue requirement equation, the ultimate objective of providing sufficient financial integrity for uninterrupted service remains the same.

5.4. One point must be stressed when applying the RR equation to estimate a regulated firm's revenue requirement: cost recovery is not guaranteed. To recover its costs, and earn its allowed return, a regulated firm must perform its duties. Moreover, all of the firm's costs must be "known and measurable," "prudent," and "just and reasonable," and its capital investment must be "used and useful."

5.5. The O&M expenses in RR equation are non-capitalised costs that are incurred in the provision of service. They include items such as maintenance, administration, depreciation, taxes and billing expenses, and so forth. The rate base in the equation equals the capital stock, less accumulated depreciation, plus working capital that is considered useful in providing service.

5.6. Once operating expenses and the rate base have been calculated, the rate of return must be determined. The overall rate of return for a company represents the weighted average cost of the firm's debt and equity. The cost of debt is generally straightforward to measure, as it is based on the firm's actual outstanding debt issues and estimates of the cost of new debt. The cost of equity is more difficult to estimate, as it cannot be directly observed and normally accepted approaches will be used for its determination.

5.7. The mechanics of those tariff calculations are important from the perspective of those who would make investments in regulated businesses—whether in South Africa or anywhere else.

5.8. It is useful to break the mechanics of actual tariff setting into the three sets of tariff-making "rules" shown in Figure 2.

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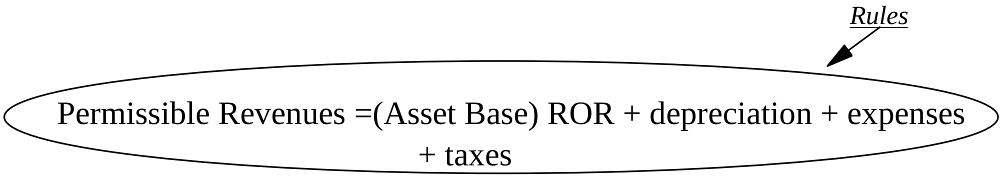
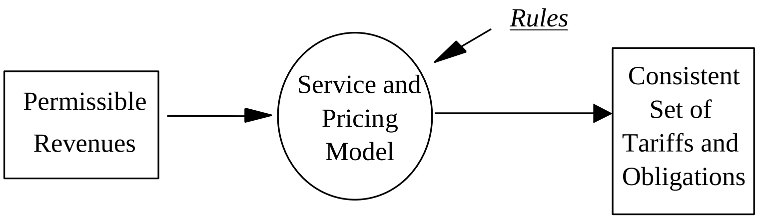
failures and more about enabling markets to work more effectively. The modern economic regulator acts as a 'visible hand' to improve economic efficiency by introducing incentives for **service providers and customers** to respectively produce and consume at levels that would have been observed in a functioning market. ESC, Victoria State, found at [What-Is-Economic-Regulation.pdf (esc.vic.gov.au)](), 27/06/2022

Figure 2 -Three Basic Sets of Rules are Needed for Tariffs

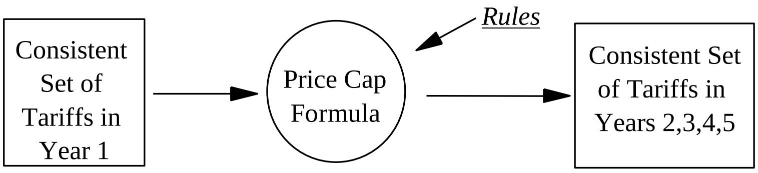
1. Rules for establishing permissible revenues (i.e. tariff level)



2. Rules for setting rates and tariffs (i.e. tariff structure)



3. Rules for altering tariffs between regulatory reviews (i.e. updating mechanism)



5.9. **Rules for Establishing Permissible Revenues**

5.9.1. The first set of rules deals with the transformation of costs (are these costs past costs or projected costs?) into a permissible level of revenues. The calculation itself can be carried out whenever requested by a licensee or the Regulator or on a set time schedule. All of the customary elements of such calculations are included, such as a fair rate of return (based on the opportunity cost of capital), an asset base, depreciation, operating expenses, and taxes.

5.9.2. The basis for calculating permissible revenues must be clearly communicated to licensees. When these rules are poorly defined or subject to excessive unpredictability, the stage is set for conflict between regulators and the regulated companies and for needless waste of resources.

5.10. **Translating costs into revenue requirement and into service specific tariffs-** The costs incurred by licensees in either generation, transmission or distribution of electricity are allowable revenue. The capacity used by licensees in generating, transmitting and distributing volume of electricity will be used in determining specific tariffs

5.11. **Rules for setting Tariffs**

5.11.1. The service and pricing model serves to create the set of standard regulated prices from the level of permissible revenues. Transforming the level of permissible revenues into a tariff structure involves a model that incorporates various things. The structure of tariffs embodies all of the elements that are considered desirable in a regulated pricing regime (e.g. fairness, efficiency, stability and transparency). Thus, the tariff structure contains, among other things, the economic signals that are intended to encourage efficient levels of usage—within the constraint represented by the need for the projected tariffs to collect the level of permissible revenues at the time those tariffs are designed.

5.11.2. Fundamental in the new tariff regime is a departure from use of sale or production in the translation of permissible revenues to use of usable capacities in the determination of all tariffs, as is the case in the determination of REIPPP tariff structures.

5.12. **Rules for Altering Tariffs**

5.12.1. The first two sets of rules apply when one is dealing with the traditional cost of service regulation, but with some alternative forms of regulation, such as price cap regulation, a third set of rules is required. These rules specify the methods used to change tariffs on a set schedule.

5.12.2. For fuel-based generation plants, a further monthly or quarterly adjustment approach will need to be included to ensure that changing fuel costs are reflected on a continuous and predictable basis.

5.13. The Revenue Requirement Methodology underpins the price setting and is the conventional methodology worldwide for economic regulation of prices.

5.14. **Key elements of methodology are discussed as follows:**

5.14.1. Regulatory Asset Base

5.14.1.1. Regulators recognise this by allowing an element within the revenue that may be collected and the associated tariffs. This is calculated by establishing the value of the assets used – called the regulatory asset base or (RAB) – and applying to this a rate of return (ROR) based on the weighted average cost of capital or WACC.RAB and ROR determination will be for each power station. Licensees whose costs are not primarily driven by the RAB will use margin to determine their profits.

5.14.1.2. The Regulatory Asset Base (RAB) must represent assets used and usable to provide regulated service by each of Eskom business operations. Regulatory assets base (RAB) will be used to determine return based on approved WACC and depreciation charges. Historical cost basis is a preferred approach for asset evaluation method when determining RAB. The information will be required per power station

5.14.1.3. The RAB of the regulated business operations must therefore only include assets necessary for the provision of regulated services based on the net depreciated value of allowable fixed assets necessary to allow the utility reasonable return to be financially viable and sustainable while preventing unreasonable price volatility and excessive sustainability.

5.14.1.4. The RAB must consist of existing Fixed Assets in use, New Investments, as well as making allowance for Net Working Capital to allow the respective operations of licensees to meet their short-term obligations.

5.14.2. Weighted Average Cost of Capital

5.14.2.1. The Weighted Average Cost of Capital **(**WACC) is the weighted average of the expected cost of equity and cost of debt. It will be used by NERSA to determine the rate that will be multiplied with RAB to grant licensees a reasonable return. The following formula will be used to determine the pre-tax real WACC:

$$WACC = [\, Ke \times g) + \left\{\frac{Ke}{1-tc} \times (1 - \ g)\right\}]$$

5.14.3. Expenses (operating and maintenance costs)

5.14.3.1. Allowable expenses relate to all expenses that are incurred in the production and supply of electricity. These costs are discussed in paragraph 5.5. A licensee will be expected to split between operating and maintenance costs. Operating costs should also include head office costs or shared costs.

5.14.3.2. Support and share of corporate costs this will entail Finance, HR, Commercial, security, Research and Development, Sustainability, Strategic and consultancy costs, Stakeholder management Board, CEO and any other related costs.

5.14.3.3. Operations, maintenance, and other site related costs include Technology Services; Environmental Compliance; Insurance; Labour; Contractors; Materials and supplies and any other information with description.

5.14.4. Primary energy costs

5.14.4.1. These costs recognise that the mix will vary between different technologies and, for example, for renewable energy using technologies such as wind or photovoltaic (PV) such costs may be low or even zero. Primary Energy costs will include fuel costs. The regulated entity will be required to report transparently the cost variances with respect to primary energy. These costs included Fuel usage (coal, oil, gas), Operational fuel, Fuel handling, Water usage and treatment and any other that can be specified.

5.14.5. Depreciation

5.14.5.1. Licensees will be allowed to include in their costs depreciation related costs for the sake of tariff determination. Annual depreciation will be calculated by deducting the Accumulated Depreciation of the previous year (year-1) from the Accumulated Depreciation the current year (year 0) using the following formula:

$D = ACy0 - ACy{-1}$

D = Depreciation and amortisation of replacement cost adjustment

$ACy0$ = MEAV*(remaining economic life year 0/total economic life)

$ACy{-1}$ = MEAV*(remaining economic life year -1/total economic life)

5.14.5.2. The economic life for the regulated Generation, Transmission and Distribution assets shall be determined by the licensees and approved by the Regulator.

5.14.6. Levies

5.14.6.1. The Government imposes certain taxes and levies that are payable by licensees that generate electricity.

5.14.6.2. The rate is determined by government, are actual payments and will be treated as allowable costs. These costs are determined by the metered generated volumes. Therefore, levies are any amount arising from an enacted legislation that the Government may require licensees to pay.

5.14.6.3. Because municipal surcharges fit the definition of the government levies and taxes, these need to be excluded from the municipal tariffs and expressly captured and reflected as pass-through costs.

5.14.7. Profit considerations

5.14.7.1. Asset based activities

5.14.7.1.1. Licensees will be allowed, a profit/ ROA based on their RAB value. RAB is a licensee's record of the net value of a company's fixed assets, from which the depreciation and return on capital components of allowed revenues are calculated. Profit calculation for assets based licensee operation, is a function of WACC and RAB. The Weighted Average Cost of Capital (WACC) is the weighted average of the expected cost of equity and cost of debt for licensees.

5.14.7.2. Non-asset based activities

5.14.7.2.1. For activities that are not asset based, for determination of the profit, a profit margin mechanism will need to be considered. Such margin setting mechanism may be based on a percentage of operating costs or benchmarks. Stakeholders are requested to comment on this approach and to propose alternative approaches.

Stakeholder Question 2

a) Stakeholders are requested to comment on the profit determination mechanism as proposed by NERSA under 6.13.7. Stakeholders are also requested to provide alternative mechanism and motivate for the proposed approach.

b) Historical cost basis is NERSA's preferred approach for asset evaluation method when determining RAB. What is the view of stakeholders on this preferred approach and provide the motivation for preferred approach?

6. Application of Principle 1 - Unbundling Value Chain Activities with tariffs

6.1. Understanding details of principle 1: Disaggregation with the value chain

6.1.1. Principle 1 deals with unbundling across the electricity value chain. The main purpose of implementing unbundling (business separation) policies is to improve competition and achieve cost efficiency.

6.1.2. Unbundling of costs at vertical and horizontal levels:

6.1.2.1. Unbundling can be either horizontal or vertical. Under these principles activities within the electricity, value chain will be recognised to allow suppliers to recover their full cost of provision of the service. The electricity value chain comprises of a series of activities. These activities are different from another and presents different costs and value drivers. There is a need for clear understanding of costs across all the activities to achieve efficiency.

6.1.2.2. Unbundling of the electricity value chain into its component activities is very common in the modern regulatory approach, which identifies specific cost drivers and then allocates costs based on the details of the utility's equipment, operation, and product mix. This approach also allows for allocation of overhead and indirect costs to related products and services. The unbundling of activities approach derives cost-reflective tariffs to give effect to the tariff principles in section 15(1) of the Act – underpinning the cost to serve.

6.1.2.3. Unbundling does not only identify the accurate cost of each service but is a decision-making tool to determine if the cost allocated is prudent and efficient. Data needs to be accurate, without correct information, it is impossible for the Regulator and utilities to make accurate decisions. This approach is a tool that can assist utilities to be more efficient and thereby be more profitable and assist regulators to make pricing decisions that reward prudence and efficiency but more importantly prices that are cost reflective.

6.1.3. Describing the data collection templates

6.1.3.1. **Generation** – this generally refers to the production of electricity at power stations (or sometimes-other locations) and all related aspects. It covers the capital cost of generation equipment (such as boilers, turbines and all associated plant) and includes depreciation and return, operating costs such as maintenance, support costs and any allocated corporate costs. The boundary for establishing generation costs is usually associated with the exit point of the electricity from the power station or generation facility.

6.1.3.2. Under generation, each power station will be required to provide general information such as commission date, installed capacity, nominal and usable capacity, power sent out, availability in a year and heat rate.

6.1.3.3. The information referred to in all five sets of data will used to set tariffs by converting using usable capacity or nominal capacity as a denominator.

6.1.3.4. **Transmission** – this part of the value chain may contain different elements depending on the structure chosen. Still, it will undoubtedly include costs associated with the construction and operation of the transmission network itself. In South Africa, transmission refers to network where the voltage is in excess of 132 kV. The transmission tariffs will form the backbone for the determining clear transmission use-of-system charges and wheeling charges that will be universally charged to give effect to section 21 (2) to (4) of the Act.

6.1.3.5. The information required is capital costs such as transformers, switchgear, lines and cables, and includes depreciation and return, operating costs such as maintenance, support costs and any allocated corporate costs. The boundary for establishing transmission costs is usually associated with the entry point for electricity from power stations to the entry (or exit) point to distribution networks.

6.1.3.6. Transmission system usage and demand data refers to units entering the transmission network (such as generation MW, international imports, international wheeling and IPPs) and units exiting the system (e.g. Eskom distribution, direct sales to customer, international export and international wheeling).

6.1.3.7. **Central** purchasing will clearly have two key functions. It will act as an independent procurement office (work currently undertaken by the IPP Office) and as a single buyer. As a single buyer, it will also have to deal with "legacy contracts"

6.1.3.8. **Independent System Operator** – the Independent System Operator is usually responsible for system reliability and safety, system security and establishing and implementing operating instructions, procedures, standards and guidelines to cover the operation of the system. There may also be a planning role. Until recently the system operator has generally formed part of transmission and in many cases still does. However, it is increasingly recognised that in certain circumstances this structure could lead to a perceived conflict of interest and hence system operation is being established as a separate organisation, sometimes under different ownership.

6.1.3.9. System operator costs are related to operation of the control room and are usually dominated by labour, Information Technology (IT) and communication costs. The cost can be broken up in the following categories;

6.1.3.9.1. Regulated Asset Base (RAB), Return and Depreciation;

6.1.3.9.2. Taxes and levies;

6.1.3.9.3. Insurance costs;

6.1.3.9.4. Operations and Maintenance and Other costs

6.1.3.9.5. Other Support costs and Transmission(Tx) share of corporate costs;

6.1.3.9.6. Ancillary Services Costs.

6.1.3.10. **Market Operator** – this activity is also often part of transmission, given the close relationship with system operation. It is generally established as a separately managed function within transmission. Its usual role is to facilitate the operation of a range of wholesale markets and linkages to trading markets (where appropriate). Costs are again likely to be dominated by labour, IT and communication costs.

6.1.3.11. Unlike the elements of the value chain examined so far, the market operator is likely to have limited assets. Nevertheless, there may be some (potentially items such as capitalised IT costs) that can be quite substantial and thus an understanding of these will be important in order to determine depreciation costs that need to be recovered. These costs will be fixed costs which is RAB for return purpose, capital expenditure, operation and maintenance and operation expenditure

6.1.3.12. **Distribution: Wires** – section 13(3) of the Act calls for the separation of the wires business from trading. Distribution wires covers the ownership and operation of distribution networks (which are defined in South Africa as those with a voltage of 132 kV and below). This part of the value chain is primarily operated by municipalities and Eskom, with a few privately operated network. The distribution wires tariffs will form the backbone for the determination of distribution use-of-system charges as well as wheeling charges that will be universally charged to give effect to section 21 (2) to (4) of the Act.

6.1.3.13. Relevant costs would be the capital cost of equipment (such as transformers, switchgear, lines and cables) including depreciation and return, operating costs such as maintenance, support costs and any allocated corporate costs. The boundary for distribution costs is usually associated with the entry point for electricity from the transmission network to the entry (or exit) point to supplying end-use customers.

6.1.3.14. **Distribution: trading** – this typically covers the buying and selling of electricity. Its main costs are those associated with aspects such as customer service, billing and vending and bad debt. The Act defines this activity as trading, which can be undertaken by Eskom, municipalities and independents traders. Within the current South African sector, Distribution: Wires and Trading have traditionally been undertaken by the Distribution Licensee, but the Act obligates NERSA to issue separate licences for both activities. Further these activities are different, present different risk profiles and require separate skills set. Lastly, the envisaged electricity market will not be possible without these market makers.

6.1.4. Purpose of Data Requests

6.1.4.1. The Energy Regulator will use the data that is been requested from licensees will be used in for the Regulator to have understanding of the cost incurred in the provision of electricity and thereby allowing licensees to recover their full cost of supply. The format in which this information is required in attached in **Annexure E.**

6.1.4.2. Stakeholder are also requested to respond to questions contained in **Annexure E** listed in each of the data collection tool for each activity within the value chain.

6.1.4.3. **Profit of SO, MO or CPA profit-** Independent System Operator's profit will be determined through an allowed margin.

6.1.5. Data intensity

6.1.5.1. The Regulator requires data from licensee to execute its mandate. For this methodology to be implemented there is a need to financial and non-financial information to be generated in a format prescribed by the Regulator as stated in section 45(1)(b) of Act "that require any person to furnish to the Regulator such information, returns or other particulars as may be necessary for the proper application of this Act". The data required need to be verified for accuracy and correctness. The data required by the Regulator is intense and NERSA has developed template to assist licensees to comply with the requirement and NERSA team will also conduct workshops to assist licensee that requires assistance in complication of the required data.

6.1.6. Data collection period

6.1.6.1. Data will be collected and submitted to NERSA once every five years (or longer) and will be reviewed on yearly basis. Data submitted by licensees will be used in costs assessment and conversion of those costs to tariffs. NERSA has developed a data collection tool that allows licensees to submit the required information in an appropriate format.

6.1.6.2. The costs information submitted by licensees will be converted into either single tariff or multiple part tariffs depending on the nature of service provided by a licensee in a manner described in section 5 of this document. Fixed costs will entail all costs that do not vary with production. In contrast variable costs will be costs that vary with production. Licensees will also be expected to indicate those costs that could be deemed to be customer-specific expenses, such as meter reading, billing, marketing or insurance costs.

6.1.6.3. At the time of completion of the workbooks, full-year figures will only be available for the previous year. Preferably, these numbers should have been audited but this will be dependent on when during the year completed workbooks need to be submitted during the year, so it may not always be possible. It will also be important to be provided with expected figures for the current year (i.e., the year during which the data is submitted). This will be a mixture of actual data for the completed part of the year and forecast for the remaining portion.

6.1.6.4. Next, a separate worksheet must be completed for each year of the MYPD period, with MYPD Year 1 being the following year after the current one and MYPD Year 2 the next and so on. The past South African practices of setting revenues over a maximum of five years is irrelevant in this case. Individual tariffs can be set for the expected life of the asset as is the case in respect of REIPPP tariffs, which are set for the duration of their PPA with the Single Buyer but allowing opportunities for reopeners when the situation changes. In the case of fuel based generation plants, reviews of fuel prices can be allowed to reflect the frequency of changes in the prices of such fuels. Because of the possible shock that such frequent reopeners may cause to the entire electricity industry, such reopeners would only be at the discretion of the regulator and must reflect a concern for an industry-wide impact of the aforementioned situation.

6.1.6.5. As with well as the cost information, licensees should submit business plans for the tariffing period which include a narrative explaining and justifying the expected costs including expected improvements in efficiency and performance. This applies to both capital and operating expenditure. In some cases, licensees may be seeking approval to recover the costs for programmes aimed at making specific improvements – for example, to support a loss reduction plan. Where this occurs, the plausible resulting benefits (i.e., reductions in technical and non-technical losses) should be fully explained.

6.1.6.6. To ensure the integrity of the pricing system, however, the overall electricity pricing system will be reviewed within period not exceeding five years.

Stakeholder question 3

a) Stakeholder are requested to comment of data intensiveness and propose solutions on how licensees can be assistance to be complaint.

b) Stakeholders are requested to comment on the proposed timeframe for licensees to submit their information.

6.2. Various tariffs within the value chain

6.2.1. Each business activity across the electricity value chain will have its own individual tariffs that are based on its fixed costs, variable costs and ancillary service costs. Consumer tariffs will be sum of Gx, Tx-system operations, Tx-market operations, ancillary service costs; Dx wires Dx trading, surcharges and or less any subsidies. In a way consumers will only pay for the costs of service, they received which is a fair and just practice. The tariffs at each business will be categorised in terms on single part, two-part or three-part tariffs. The costs that will be converted into tariffs at each business will be split in terms of variable and fixed costs. Tariff determination at Gx(Generation), Tx(Transmission) and Dx(Distribution) will be different due to a factor that drives business activities at each point of the value chain. Detail on costs and tariffs within and across the value change is attached as **Annexure F**.

7. Application of Principle 2 – Understanding Consumer Needs

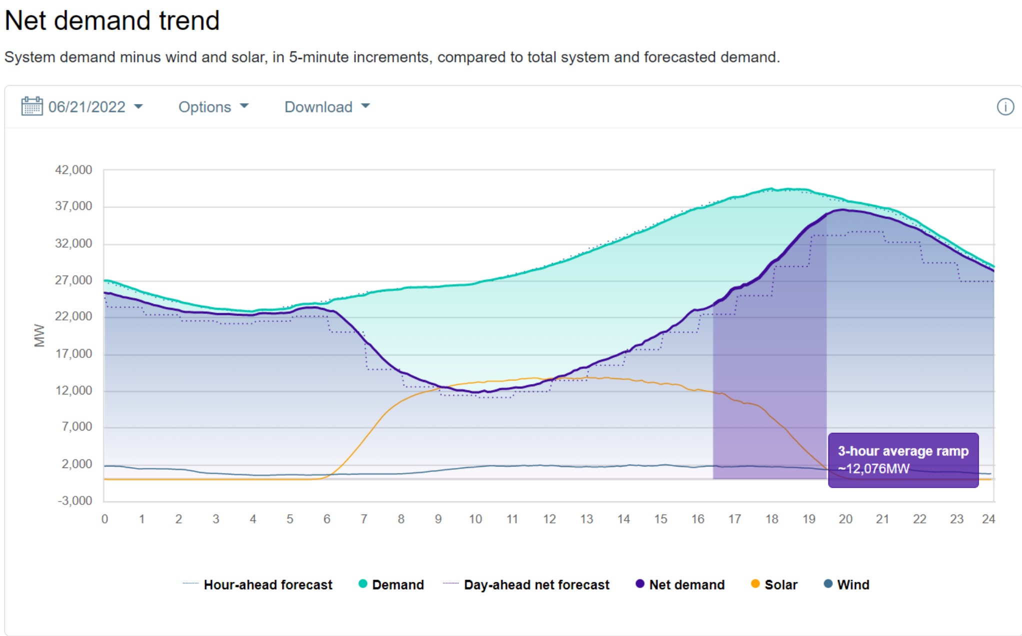
7.1. Load Types

7.1.1. It must be borne in mind that a type of load is not specific to a particular consumer, as any consumer has the potential to impose all types of load on the system at any point in time. The cumulative load over time per customer that will determine what a consumer pays for the power service they have contracted. Load is a demand side concept that has been co-opted by the supply side to describe the equipment dispatched to meet different demand profiles, thereby understanding the different loads by a consumer over time and why the profile looks the way it does – "*baseload reflects demand, not supply*" (IRENA, 2015).

7.1.2. Base load is the load that is driven by the consumption needs of the end user whereas base load capacity is the equipment operated to deliver that load and thereby meeting that demand. The same can be said for all loads. Changing the equipment to meet any load/demand (ceteris paribus) does not change the nature of the load it is not driven by the type of supply, but by the type of use consequently, we are referring to Loads 1, 2, 3 and 4.

7.1.3. An important consideration for understanding consumer loads and resultant demand is that "it is what it is". Consumers don't change their business because the supply of power changes – their business is their business. They may decide to no longer be in that business if the power is not what the need as a last recourse. Trite as this may sound, it is a fundamental recognition of the fact that consumers don't use electricity because it is supplied, but suppliers provide power because it is consumed. The load is a result of the different equipment and devices that are used for the activities the consumer is engaged in – see "Load" under Definitions. Alternative supply options may displace conventional supply during the day, for example solar power is increasingly displacing conventional supply options. The hard reality is that this does not displace the load as can be seen in Figure 3. Consumers carry on with their activities, and when the alternative supply option is no longer available, then their load still needs to be met.

Figure 3 - Example of the residual load curve (California example)



Source: https://www.caiso.com/TodaysOutlook/Pages/supply.html#section-supply-trend

7.1.4. Loads remain on the system (residual demand) in the afternoon/evening, as can be seen from the Californian “Net Demand Trend” example in Figure 3. This demand now needs to be met from other sources. This load curve clearly indicates the differences between intrinsic consumer load and the residual demand profile versus the same view from the grid supply point of view. It is important that these concepts are not mixed. Load does not change because it is met differently because load is a fundamental demand side concept and driven by consumers of power, not producers of power.

7.1.5. The methodology recognises the fact that different uses of electricity will attract the appropriate economic cost for the consumption, while different levels of consumption are characterised by different loads. Most consumers will exhibit load profiles consisting of all types of loads depending on the mix of activities they are engaged in. Energy demand can be broadly categorised into four demand profiles, for the purposes of this Consultation Paper, namely:

7.1.5.1. Load 1 - Constant power demand[12] 24/7, will likely going to be 100% grid based

[12] The various loads have terminologies that are well known but are associated with the supply of electricity. eg. baseload power plant – however baseload is a demand side concept and describes the consumption and resulting load that is imposed on the system. The equipment used to meet the base load demand was labelled baseload power supply, and consequently has become the more common usage. This misrepresentation of the load type as a supply side reference has led to the narrative that “baseload is dead” and similar misguided opinions. The reality is that regardless of the supply side response, base load will not go away because it is met by different technologies, as it relates to the

7.1.5.2. Load 2 - Day or mid-merit demand which will probably be supplied by own and embedded generation mainly through solar and wind, which will be on or off the grid. With the greater penetration of self-generation technologies, this load profile could potentially results result in negative or reduced residual demand as depicted in Figure 3 above. –

7.1.5.3. Load 3 - Variable load which will include peak demand and the load emanating from self-generating consumers returning to the grid.

7.1.5.4. Load 4 – Emergency power that is unpredictable and could include load from consumers that are using the grid as their backup system.

7.2. Know your Customer

7.2.1. The build-up of various loads over time, as required by the demands of the consumers' activities, can be monitored and, with the aid of a smart meter, measured to develop a load profile.[13]

7.2.2. The output of Principle 2 is a study of the demand side, which will be conducted in a two-step process that will examine the following towards a thorough understanding of the consumers and what they need and expect from the electricity system as introduced in 4.5.3:

7.2.3. **Role of Electricity** – Understanding the consumer: in order to understand the consumer and the expectations and requirements of electricity system, we need to collect a lot of data to understand:

7.2.3.1. What do consumers use energy for? This is not the sector they belong to or any such arbitrary categorisation that crudely lumps consumers together because of the economic sector or how much energy they use. It is fundamentally about developing a coherent understanding of how they use the energy.

7.2.3.2. The response of the system to the load from consumers will impact of the activities for which the power is used. For commercial enterprises, the impact will be largely focused on productivity and profitability, whilst households will be impacted

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nature of the consumption and the needs of the consumer and what the power is used for. For this reason, this Consultation Paper will refer to loads as Loads 1, 2, 3 and 4 which will be defined accordingly.

[13] It is possible to group consumer into categories with similar load profiles, which loosely means they may have similar costs associated with delivery of required services – this would likely be an exercise in futility as consumers will be billed for their consumption by load and therefore there will be no purpose (from a price setting perspective) to allocate costs to consumers. Suppliers may wish to do this for their own purposes but from a price setting perspective it will be superfluous.

by affordability and living standards. Either way, the quality, price and reliability of electricity will have different impacts depending on the purpose for consuming electricity in the first place.

7.2.4. **Consumer Load Profile** – understanding the consumption pattern over time (see **Annexure G** for an example of load profiles):

7.2.4.1. In order to build a load profile, data will need to be collected from consumers. For large consumers, it is not unusual for load profile data to be collected as a routine operational activity. For smaller consumers and households, metering is often much less proactive and often rudimentary – such as getting a monthly meter reading – but with no information about how the various load types cumulatively make up the meter reading. Smart meters are a good solution and can generate significant data that could be used to develop a demand profile.

7.3. Relationship between Load and Price

7.3.1. The evaluation of consumer energy needs and the associated characteristics of the consumer's use of energy and the determination of consumer load profiles are fundamental to determining cost reflective electricity prices – i.e. prices where the consumer is actually paying for the energy solution provided in a manner that reflects the economic cost of their consumption. However this is dealt with under section 8 of this document.

7.3.2. The purpose of the principle of understanding electricity consumers' needs and determining load profiles is to verify if power is affordable and/or competitive for different users. Where the affordable/competitive price is less than the cost reflective price, then the government has an accurate basis upon which to subsidise different sectors, or not. A key assumption is that electricity prices will be benchmarked against regional and international prices to determine what is an affordable or competitive price.

7.3.3. Cost-reflective prices that signal the economic cost of consumption for a particular load profile is critical to determining what level of subsidy might be necessary to address affordability/competitiveness issues and ensuring that subsidies are correctly quantified and allocated.

7.3.4. This is an important move to a more transparent and realistic pricing approach as the regulation of revenue to date has created this perception that a lower price to once customer means another has to pay more because the revenue is fixed and "guaranteed". The technical reality of employing a Type-of-Use approach, where some loads simply present a lower cost of production than others.

7.3.5. When subsidies are deemed necessary for particular consumer groups, these will be clearly identified and presented to the relevant authorities for consideration. For example, in the case of households, if a need for a subsidy has been identified based on the underlying cost-reflective price, the assessment and payments could actually be provided via the Social Welfare services. Unless clearly justified this subsidy will not be paid by other electricity users but would be paid through the budget of the appropriate ministry.

7.3.6. Similarly, for industrial consumer requiring a subsidy due to government's decision to subsidise certain sectors to promote development, such a subsidy will be provided for by the relevant industrial policy ministry.

Stakeholder question: 4

Please comment on the Role of Energy and Consumer Load Profiles:

a) Are these representative?
b) Are there others we should consider?
c) What are your specific needs that should be addressed? Please provide data/evidence of the needs you believe should be addressed.
d) Is the collection of data a risk to privacy laws? What interventions could be employed to mitigate any risk you believe exists?

Please comment on the relationship between load and price outlined above concerning the following:

a) Do you agree with cost reflective tariffs? Please substantiate your answer.
b) Do you agree with the move away from regulating revenue to regulating prices? Please substantiate your answer.
c) Do you agree with setting subsidies (where appropriate) based on cost reflective prices? Please substantiate your answer.

7.4. Data requirements

7.4.1. To perform a load analysis and develop load profiles for different uses of power, as mentioned before, will require significant amounts of data should be provided to NERSA to enable the application of the principles outlined in this Consultation Paper and which will be incorporated into the new Electricity Price Determination Methodology (EPDM). The data requirements will be, inter alia, as follows:

7.4.1.1. Peak Load-Daily,Weekly and Monthly

7.4.1.2. Electricity Consumption – 24 hours, weekly and monthly at half-an-hour or one hourly intervals

7.4.1.3. Pricing - businesses: prices being paid, competitive prices in other areas of operation – regional and international

7.4.1.4. Pricing – households: alternative energy solutions – eg. Solar or LPGas etc.

7.4.1.5. Sensitivity to power quality fluctuations – less than an hour, more than an hour but less than four hours and subsequent impacts

7.4.1.6. Competitiveness and affordability data – role of electricity in consumer activities:

7.4.1.6.1. proportion of energy costs to overall business; and

7.4.1.6.2. proportion of energy costs to overall household budget;

7.4.1.7. It would of course be better if such information is presented in a dynamic demand model, which may assist with decision making.

7.5. **Use of the data**

7.5.1. The data will be used to answer the fundamental questions raised in paragraph 4.5.3 – namely, the role of electricity on the sustainability of a business and standard of living of households

7.5.1.1. Comprehensive data collection will be essential to plot the different loads as a build-up within the profile, enabling the unbundling of the consumption into load types. For example, Load 1-steady throughout the day (24 hrs), Load 2 for the duration of the office hours (12 hours) and Load 3-peak during the morning and evening (2-4 hours) and Load 4- if relevant.

7.5.1.2. Initially, NERSA may begin with energy demand side surveys to source data, but as the penetration of smart meters gathers momentum, NERSA will be able to source data from the traders (or other players that install smart meters and choose to self-report). Formal data reporting templates will be developed as part of the implementation of the EPDM.

7.5.1.3. Concerns has been raised about the data that will be needed to implement the new Electricity Price Determination Methodology. Some would argue that somehow the provision of the data to the NERSA could threaten data privacy and related protections. It is critical to understand that the required data for the determination of the load profile will not enable NERSA (or anyone else) to identify appliances associated therewith. The data collected will merely reflect the increases and decreases in the electricity consumption patterns and not the source of those changes.

7.5.1.4. Prosumers will need to have smart meters anyway, to monitor their export of power to the grid, to allowing them an opportunity to be compensated for power sold. For those unable or unwilling to provide data, and or install a smart meter, the concept of a benchmark demand profile has been suggested.

7.6. **Load 1 Analysis**

7.6.1. Load 1 relates to consumption that is at a constant level, 24/7. Consumers with largely high-volume Load 1 profiles and minimal other loads will be reliant on competitive and reliable power as a critical cost driver to the sustainability and profitability of the business. High volume Load 1, or energy intensive users, will requires high quality, reliable and competitive electricity, as its will be a critical cost driver. Any fluctuation in quality, reliability and price will have a fundamentally impact on the sustainability of the business as power = productivity = profitability for these consumers.

7.6.2. That is not to say that small volume Load 1 consumption will not require these characteristics as a refrigerator will need reliable 24/7 power which if interrupted for long periods will result in damage to perishable frozen goods. However, the level of consumption will not be a determining cost factor in the overall load profile for a household. This will require significant data and related systems and tools to analyse the data.

7.7. **Load 2 Analysis**

7.7.1. Load 2 is anticipated to relate to consumption that is at a semi-constant level, e.g. office hours from 08:00 to 17:00. Many of these consumers will be industrial or manufacturing or commercial sector business that will need reliable power with prices competitive for the nature of the business and the load profile. The underlying parameters will be similar to the Load 1 – what power, how much and when is it required but equally important, what impact does power have on the business.

7.7.2. Where businesses are less sensitive to price, but very sensitive to reliability, the consumer profiles might indicate the willingness accept a higher economic cost. Due to the impact on productivity, for example where labour costs are much higher significant than electricity costs, then such a business may be willing to pay more for access to power that is more expensive. Retail shopping malls that install back-up generators to deal with load-shedding are an excellent example of such consumers (and their tenants) as back-up power is much more costly than grid supply but the higher value of keeping the business doors open, offsets the higher cost of electricity. This will require significant data and related systems and tools to analyse the data. Once again, the use of smart meters will be critical to monitor and allocate the various loads to the consumer load profile from the electricity consumed.

7.7.3. It is important to note that with time, with greater penetration of renewable energy, especially solar, the residual demand associated with this load could potentially be lower than even load pattern 1, resulting in supply exceeding demand, as it has happened in places like California (please see Figure 3 above). It is this oversupply that will potentially promote green hydrogen production.

7.8. Load 3 Analysis

7.8.1. Load 3 is anticipated to be consumed by consumers with short-term energy needs where consumption that is inconsistent, generally in the early morning and late evening hours from 06:00 to 08:00 and 17:00 to 21:00[14] respectively and/or seasonally changes depending on the inclement weather when the primary use of energy is for alternates between space heating/cooling. Typically, these are households preparing meals or water heating in the morning or evening.

7.8.2. Lighting before the sun rises and after sunset – i.e. mainly in the early morning and evening hours which is used to enable households and business to start the day and end the day by keeping the night-time at bay, although contributes to this load, its contribution is marginal. A significant amount of the Load 3 is anticipated to be from households and the hospitality sector; however, it is also households that have alternatives to shifting their load away (or removing their energy demand entirely) from these peak demand periods. Therefore, comprehensive household surveys will be necessary to determine the nuances of socioeconomic impacts on electricity demand.

7.9. Load 4 Analysis

7.1.1 Load 4 is anticipated to be most the variable and unpredictable, as it is essentially an emergency load that results from unexpected system failures in the system or unexpected demand surges and that if not supplied could irreversibly destabilise the electricity system and probably trigger large scale load shedding. Such load would likely, would need equipment that could respond very quickly with short notice from cold start – such as an OCGT or Pumped/Battery Storage or generators. Therefore, the pricing of the electricity used for this purpose must reflect the costs associated with equipment that would need to be used for such purposes

[14] The onset of this load will change depending on the penetration of solar and other forms of variable energy supply options.

– this service must haves priced as a form of insurance with availability charge (fixed, to compensate for the overheads) and energy charge for actual power consumed on an *ad hoc* basis.

7.1.2 Emergency power is already a feature of the South African electricity scene, as witnessed by many businesses and households with back-up diesel generation sets[15] that kick in when load shedding (or any other power failure) happens. This is expensive and generally limited to small and moderate loads where electricity loads are moderate and costs are not a large proportion of overall costs. Because most of these diesel gensets disengage when grid power is restored is testament to the cost thereof and the avoidance of consuming emergency power unless forced to do so.

7.1.3 It is also unfortunate that currently some of the affluent members of the South African society who have mostly moved to self-generation are using the grid for the supply of this load. If, for whatever reason, they have insufficient own production they get power from the grid and because of the relatively low amounts or shorter duration, some even buy the requisite power at the lowest tariff levels, for the domains that offer inclining block tariff.

7.1.4 While the situation may not be so bad at the moment, greater penetration of renewable energies, especially when large energy users shift to own variable supply and use the grid as backup, this will present major challenges for grid stability. Even more unfortunate though is that if the costs associated with this load are socialised, the poor and less fortunate will be the ones that carry a disproportionate amount of this cost.

[15] An engine–generator is the combination of an electrical generator and an engine mounted together to form a single piece of equipment. This combination is also called an engine–generator set or a gen-set. A genset is typically a combination of an engine, and an alternator. An engine converts the chemical energy of a fuel to mechanical energy. That mechanical energy is used to spin the alternator rotor, converting mechanical energy to electrical energy. In many contexts, the engine is taken for granted and the combined unit is simply called a generator.

Stakeholder question: 5

a) Do you have anything to add to the Load analysis above? Please comment on your answer.

b) Do you agree with the four loads outlined? Please comment on your answer.

c) NERSA will need significant data. Large users will often have detailed information available, but for most customers, anticipates collecting this data from the roll-out of smart meters. Do you think this is a reliable source of data? Please comment on your answer.

d) Large users are aware of the impact of their load on operations for themselves and suppliers, However, South African are generally aware of the power usage in terms of the monthly bill, but often have a very weak understanding of how their loads define their demand profile. It has been postulated that NERSA could have a portal where consumers could calculate their energy usage and subsequent loads types the impose on the system. How do we increase awareness of electricity usage? What other options are available to advocate for greater awareness?

e) For those consumers that do not have smart meters and it is uneconomic to install such meters (either for the consumer (eg. households) or the supplier) the concept of a benchmark demand profile is being considered as a proxy for the actual the loads consumed. Do you agree with this approach? Is there a better approach?

f) NERSA will prepare rules on the provision of data (much as it has for licensees) but this will be novel for consumers. What constraints do you foresee in providing data to NERSA for setting electricity prices that are fair and transparent and cost reflective?

g) Energy demand surveys have postulated as an option to obtain data. What other sources of data would be a reasonable substitute for smart meters?

8. Application of Principle 3 – Cost-Reflective Consumer Price Setting

8.1. Introduction

8.1.1. Electricity prices have a profound impact on households in terms of affordability and quality of life as well as on the competitiveness and sustainability of businesses. Determining rates to charge customers can be a contentious issue with serious social and economic consequences. An important tool in rate design includes marginal cost determination and related pricing. Basing prices on marginal costing, or a suitable and reasonable proxy, weighted average cost (WAC) pricing, in the period preceding the market, can be beneficial and should be the dedicated pursuit of NERSA, assuming these following;

8.1.1.1. Prices must signal the economic cost of consumption;

8.1.1.2. Prices must be cost reflective;

8.1.1.3. Prices must be efficient and fair;

8.1.1.4. Social costs and benefits must be considered once baseline prices have been determined.

8.1.2. The determination of fair and transparent consumer prices will not be possible without robust adherence to the merit order of dispatch of power by an Independent System Operator as a fundamental principle for operating an electrical system and an essential input for setting fair prices that signal the economic cost of consumption – regardless of whether it is in a regulated or competitive/functioning market

8.2. Approach

8.2.1. Electricity prices have a profound impact on households in terms of affordability and quality of life as well as competitiveness and reliability of business respectively. Determining rates to charge customers can be a contentious issue with serious social and economic consequences. Consumer prices will be set using the formula outlined below, noting that related concepts (such as merit order etc.) are covered in detail in Section 4.6:

Consumer price = Appropriately weighted {Load 1 WAT + Load 2 WAT + Load 3 WAT + Load 4 WAT} + Transmission network Tariff + Ancillary services charges + System/Market Operations Tariff (Management fee) + Central Purchasing Agency (CPA) tariff (Management fee)

+
including REIPPP levies – assessed quarterly
+
Distribution component
+
Trading component
+
Municipal Surcharges
+/-
Subsidies

8.3. Overview

8.3.1. In respect of the generation part of the price formation, consumer prices will be based on a weighted average tariffs derived from a merit order dispatched approach of dispatching power to meet the different loads on the system and the alignment of the respective loads to the type of service each value chain activity provides. The final price paid by the consumer will consist of all components of value chain determined under activity 1, it will be the sum of the Generation charges, Ancillary Services, Transmission charges, Distribution charges and trading charges.

8.4. Application

8.4.1. The core aspects of the formula for calculating consumer prices will now be outlined in more detail

8.4.2. Load 1 tariff + Load 2 tariff + Load 3 tariff + Load 4 tariff

8.4.2.1. The Independent System Operator (ISO) submits forecasted energy demand by 10:00 am every day for the following day, while all qualifying generators are expected to submit their planned plant output (committed availability) by 14:00 every day for the following day. The SO is expected to dispatch resources on the least cost merit order based on the power made available by all qualifying generators.

8.4.2.2. The Independent System Operator will call up power plants in merit order to meet the different loads as they come onto the system and record which generators delivered power and how much over the 24-hour period. The detail of how loads and load profiles are linked to the consumption of power and provide inputs for setting prices outlined here, are discussed in section 7. In a functioning market, the costs associated with the last plant that 'balances' the market (marginal costs) would set the marginal price for that service.

8.4.2.3. Marginal price is an important tool in consumer price determination however it is largely a market concept for discovering prices and therefore in the absence of a functioning and competitive market, a suitable and a reasonable proxy is required. Therefore, a weighted average tariff (WAT) approach, has been proposed for the period preceding the introduction of a functioning electricity market – i.e. WAT for each load based on the power actually delivered and monitored by the Independent System Operator, as calculated below:

8.4.2.3.1. The weighted average will be determined by summing up the products of a dispatched plant tariff multiplied by power dispatched from that plant for each power plant dispatched divided by the total power dispatched to meet that load.

8.4.2.3.2. The following formula seeks to represents the description above:

$$Weighted\ Average\ Tariff\ Load\ 1\ (\mathrm{WAT1}) = \frac{\sum_{i=0}^{n} T_i\ x\ X_i}{\sum_{i=0}^{n} X_i}$$

$$where\ T_i = tariff\ of\ plant\ i\ that\ has\ been\ dispatched\ to\ meet\ load\ 1$$

$$and\ X_i\ equals\ the\ power\ dispatched\ to\ meet\ load\ 1$$

8.4.2.3.3. The formula is repeated for each load type. This then becomes the Load Price that will be charged for each load within a consumer load profile. Each other activity tariff associated with servicing each load type will be summed in proportion to the amounts consumed in each load type to reach the overall billing for any particular consumer. It is important to note that for those consumers who are using smart meters, the amounts per load will be based on the actual amounts consumed in each load. For those consumers who do not have smart meters, their total consumption will be proportioned out based on a generic consumption pattern for a particular consumer group to which the consumer will be deemed to belong.

8.4.2.4. The energy component of consumers prices will recognise each load at the WAT of that load. The resultant ‘generation’ price is shared among the various customers proportionately according to the actual metered energy consumed by each customer for their particular load.

8.4.3. Transmission network Tariff + Ancillary services charges

8.4.3.1. The transmission use of system changes will be based on the transmission tariff set in Principle 1

8.4.4. System/Market Operations Tariff (Management fee)

8.4.4.1. The charges for this service will be as set in Principle 1.

8.4.5. Central Purchasing Agency (CPA) tariff (Management fee)

8.4.5.1. The charges for this service will be based on the tariff set in Principle 1.

8.4.6. All levies, including REIPPP levies – assessed quarterly

8.4.6.1. The levy will be charged as per the mechanism described in paragraphs 8.4.12.1 and 8.4.12.2.

8.4.7. Distribution component

8.4.7.1. The distribution use of system changes will be based on the transmission tariff set in Principle 1

8.4.8. Trading component

8.4.8.1. The charges for this service will be based on the tariff set in Principle 1.

8.4.9. Municipal surcharges

8.4.9.1. Municipal surcharges imposed in terms of the Constitution and Municipal Systems Act, 2000 (Act No. 32 of 2000), will be treated like taxes, hence they will be a pass through. Currently the surcharges are simply part of the Municipal tariff, but not ring-fenced and transparently itemised. (e.g. environmental tax and carbon). It will be necessary to determine whether the tax is fixed or variable – e.g. a carbon tax that goes up as more coal is used would be a variable component of the consumer price.

8.4.10. Subsidies

8.4.10.1. As discussed in paragraph 8.4.12.6, subsidies will be added or subtracted as appropriate.

8.4.11. It is clear that the pricing equation in paragraph 8.2 above is easy to deal with for one part tariff structures. Two challenges arise however for tariffs that have an energy charge and capacity charge. Dealing with the energy charge part is straightforward. The first challenge is adding up energy charges and capacity charges. It is clear that these will need to be reflected separately in the consumer bill. The second charge is how fixed charges, which may be presented as Rands/per month for each activity and sub-activity will be allocated to each consumer. The suggestion is that fixed charges be allocated, based on the relative consumption by each consumer of the each of the load.

8.4.12. As with any economic regulation, there are concerns about unintended consequences and anomalies that need to be addressed to avoid introducing price distortions that result in ill-informed allocative decision and related investments with possibility of stranded assets. Some of these considerations for ensuring the robustness and sustainability of the new Electricity Price Determination Methodology are outlined below:

8.4.12.1. **Preserving the sanctity of merit-order dispatch:** generators will only be compensated for the energy if they are dispatched. Generators can only be dispatched if they have a tariff set by the Regulator. Dealing with legacy REIPPP PPAs where take or pay PPAs guarantee compensation for self-dispatched energy despite tariffs that are 2-3 times the current Eskom average electricity price and more than 10 times the recent IPP bid prices, is going to be a challenge. In terms of the merit order dispatch rules, such plants probably never get dispatched and therefore would receive no revenue. However the guarantee in the PPA ensures that there must be compensation. Expensive self-dispatching plants cannot trump another generator if merit order applied rigorously. Therefore such contracted IPPs would need to be compensated through a levy that is paid for by all electricity users.

8.4.12.2. **Self-dispatching plants**: Solar and wind power plants are generally self-dispatching and are sometimes considered as “must-be-dispatched” plants. However, in a merit order system, it would be unfair to have a plant that should have been dispatched in terms of the merit order but is displaced by “self-dispatching” plants. An approach will need to be designed that ensures the fairness of the system and the integrity of the merit order dispatch approach. It is inappropriate to have plants that are dispatched at whatever costs.

8.4.12.3. **Regular price assessments for predictability** – Price predictability will be underpinned by quarterly price reviews based on the dispatched data provided by the Independent System Operator. The proposal is for the price to be reviewed every quarter using the information obtained in the preceding quarter – ie. Prices will be assessed and possibly adjusted quarterly, in arrears. In the first year, the review of the price will not necessarily mean the consumer prices will be adjusted quarterly. The quarterly dispatched data may be used only in the following year to make adjustments if there have been any under recoveries or over recoveries. Quarterly price determination method may then be adopted in the second year of application.

8.4.12.4. **Rewarding positive load shifting** - If a consumer shifts their load from a more expensive load period to a cheaper load period, then the prevailing WAT for that period will apply. This will serve as an incentive to consumers to use electricity optimally. (See **Annexure H** for narrative on Time-of-Use tariffs).

8.4.12.5. **Benchmark Demand Profile**: The above price setting approach will require significant penetration of smart meters, however where households cannot afford a smart meters, the concept of a benchmark household is being considered. The benchmark household will be designed using information from actual households. Once the proportions of Load 1, 2, 3 and 4 are defined, a household's actual metered consumption will then be allocated accordingly. For example, if the benchmark household was deemed to use 10% of consumption as load 1, 50% as load 2 and 40% as load 3, then and actual usage of 500 kWh would be located as 50 kWh @ load 1 price, 250 kWh at Load 2 price and 200 kWh at Load 3 price, with regard to the generation part of the bill.

8.4.12.6. **Subsidising electricity consumption**: Designing subsidy regimes will benefit from the sophisticated approach to setting consumer tariffs. In future subsidies will be determined by the difference between the cost reflective prices and what consumers can prove is the competitive or affordable price for business and households respectively. Once the subsidy level is determined, it would be dealt with as in paragraphs 7.3.5 and 7.3.6 above.

Stakeholder question: 6

a) Do you believe the concept of the benchmark demand profile is fair? Please comment on your response.

b) Do you believe separate ancillary services tariffs are reasonable? How would they be calculated? Please comment on your response.

c) Do you agree with the concept of the legacy IPP levy to pay for the self-dispatched power? Please comment on your response.

d) Should legacy IPP PPAs with a capacity charge be part of the abovementioned levy? In other words should everyone have to pay for capacity set aside for specific users?

e) How often do you think pricing reviews should be done? What is the reasonableness of monthly, quarterly, bi annually or annual price reviews and why?

Stakeholders are requested to comment on the following:

f) The consumer pricing methodology guidelines.

g) The fairness of the Time-of-Use approach.

h) The fairness of the Type-of-Use approach.

i) The linking of loads to the economic cost of consumption, as the foundation for electricity prices, is intended to send the correct signals to consumers that will enable them to make informed choices about their energy consumption. Do you agree with this approach and what other signals could be used to achieve this outcome.?

j) What other approaches could be considered to send the correct pricing signals to those whose loads require appropriate technologies to cost effectively meet their demand cost-effectively.

k) Whether the approach to mimic market forces in determining electricity prices is fair or not? Please comment on your response.

l) What other options should be considered for rewarding loads shifted to a lower price load as a positive behaviour change from the price signals?

9. Conclusion

9.1. Sections 14 and 15 of the Act, clearly mandate NERSA to set or approve tariffs for licensed activities. The Act also allows for regulation of revenues, an approach that has been used extensively in the past. Changes in the industry and distortions have forced NERSA to better comply with the prescripts of the Act. It is with this in mind that the Tariffs Determination Approach has had to move from regulating Eskom Revenues to setting electricity industry tariffs that are used to determine cost-reflective consumer prices. However, the revenue required (RR) methodology will however still be used as the basis of tariff setting.

9.2. One of the key factors in establishing a fair and equitable Electricity Pricing Methodology is access to adequate data, at a level of granularity that allows the Energy Regulator to make informed decisions. As decisions are being made on unbundling and restructuring the industry, it makes sense to put in place systems, which will allow for the costs associated with the different industry participants to be transparent and comparable. The workbooks discussed in this Consultation Paper are fundamental in the determination of unbundled cost-reflective tariffs and setting of appropriate, fair prices for customers.

9.3. Another critical success factor will be the robust adherence to the merit order of dispatch of power by the Independent System Operator as a fundamental principle for operating an electrical system and an essential input for setting fair prices that signal the economic cost of consumption – regardless of whether it is in a regulated or competitive/functioning market

9.4. The Energy Regulator will conduct a review of the Electricity Price Determination Methodology as and when required to ensure that the contents of the Methodology reflect the current regulatory circumstances. NERSA also recognises that special circumstances may arise that may necessitate changes to be effected to the Methodology. Accordingly, NERSA will continuously incorporate justifiable changes that are considered necessary to immediately capture clarity, transparency and regulatory efficiency benefits immediately.

10. The Consultation Process

10.1.1. Stakeholders are requested to comment in writing on the Consultation Paper on the Methodology for the Determination of Tariffs and Prices in the Electricity Industry. Written comments can be forwarded to mypd@nersa.org.za; hand-delivered to Kulawula House, 526 Madiba Street, Arcadia, Pretoria, or posted to PO Box 40343, Arcadia, 0083, Pretoria, South Africa. The closing date for the submission of comments is **29 July 2022** at **16:00**.

10.1.2. NERSA will collate all comments received, which will be taken into consideration when the decision is made. In addition, public hearings will be held using MS Teams; wherein interested and affected parties may make presentations.

10.1.3. The process for consultation and decision-making is outlined in the table below:

Table 1: EPDM Consultation Programme

Task Name	Start	Finish
Revision of Pricing Framework and t methodology (EPDM)	**Mon 22/04/25**	**Fri 22/09/30**
Special ELS approves publication consultation paper	Fri 22/06/24	Fri 22/06/24
Publish on website/Newspaper	Mon 22/06/27	Thu 22/06/30
Public Consultation	**Thu 22/06/30**	**Fri 22/07/29**
Closing date for comments	Fri 22/07/29	Fri 22/07/29
Public Hearings	Thu 22/08/04	Wed 22/08/10
ER Decision on the Final Methodology	**Fri 22/08/26**	**Thu 22/09/29**
Final Methodology presented to Extended ELS	Fri 22/08/26	Mon 22/09/05
Final Methodology presented to ER - scheduled ER	Thu 22/09/22	Thu 22/09/29
Successfully published	Fri 22/09/30	Fri 22/09/30

End

11. Annexures

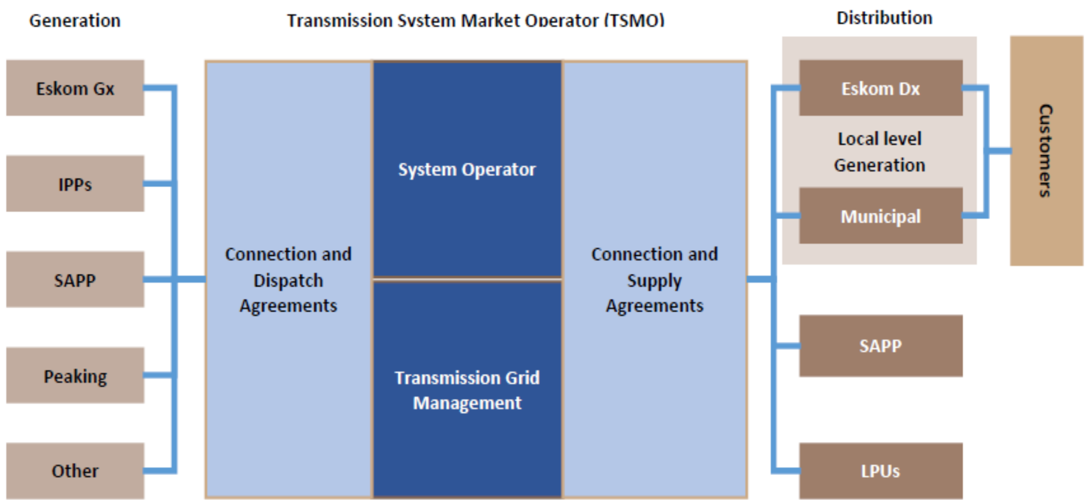
11.1. Annexure A: Evolution of the MYPD Methodology over time

	Applicable dates					Key basic MYPD issues			
Control Period	Consultation Paper published	Methodology approval	Eskom Application	Implementation - start	Implementation - end	Methodology Used	Principles applied		
							Profit compensation	Y-2-Y variance	RAB evaluation
Pre-MYPD	N/A	2002	Yearly	N/A	N/A	RR – Costs +RoR	CAPM	Yearly determination	Book
MYPD 1	2 Aug 2005	Principles: 22 Sept 2005 Updated rules: 20 Dec 2007	30 Sept 2005 30 April 2007	1 April 2006 1 April 2008	31 Mar 2008 31 Mar 2009	RR – Costs +RoR	CAPM	CPIX+	Book
MYPD 2	20 Oct 2008 12 Dec 2008	26 Mar 2009	5 May 2009 - interim 7 Oct 2009	1 July 2009 1 April 2010	31 Mar 2010 31 Mar 2013	RR – Costs +RoR	CAPM	RCA	Current
MYPD 3	14 Oct 2011	28 Feb 2012	7 Aug 2012	1 April 2013	31 Mar 2018	RR – Costs +RoR	CAPM	RCA	Current
MYPD 4	14 April 2016	19 Oct 2016	25 Aug 2017 - interim 14 Sept 2018	1 April 2018 1 April 2019	31 Mar 2019 31 Mar 2022	RR – Costs +RoR	CAPM	RCA	Current + WUC

11.2. Annexure B: Market Structure options – depends on the optics!

11.2.1. In the reformed electricity market, the transmission systems operator will have to act as an unbiased electricity market broker, to promote capital investment within the electricity demand and supply industry and to catalyse energy efficiency and sustainability. Unbundling also allows for the ISO to independently contract with independent power producers and Eskom generation without the conflict of interest, as it currently exists.

Figure 4: Eskom's view of a future electricity market[16]

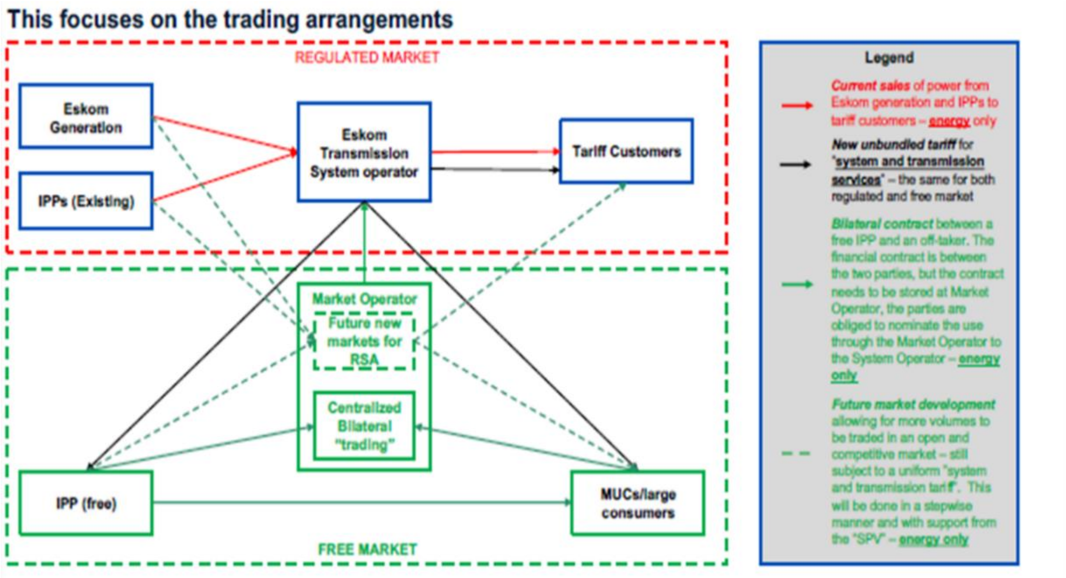


11.2.2. The market structure depicted in Figure 4 is very much seen through the Eskom lens of a domain player with significant market power, whereas alternatives may introduce increased voluntary market participation. Deregulation is anticipated to reduce Eskom's dominance by introducing competition and consumer choice. However Eskom will likely remain a powerful player in the South African region for a number of years to come.

11.2.3. As shown in Figure 5, the electricity market model can be viewed in different ways which in this instance, represents the European market model, also found in India and other Asian countries. Regulatory and legal arrangements illustrated in Figure 5, give expression to the ambitions of traders and generators who wish to bilaterally contract with end users - either directly with onsite supply or wheeled over the grid. In wholesale most of the markets power is bought through bilateral contracts and the remaining power through spot markets which acts as a clearing house for buyers and sellers.

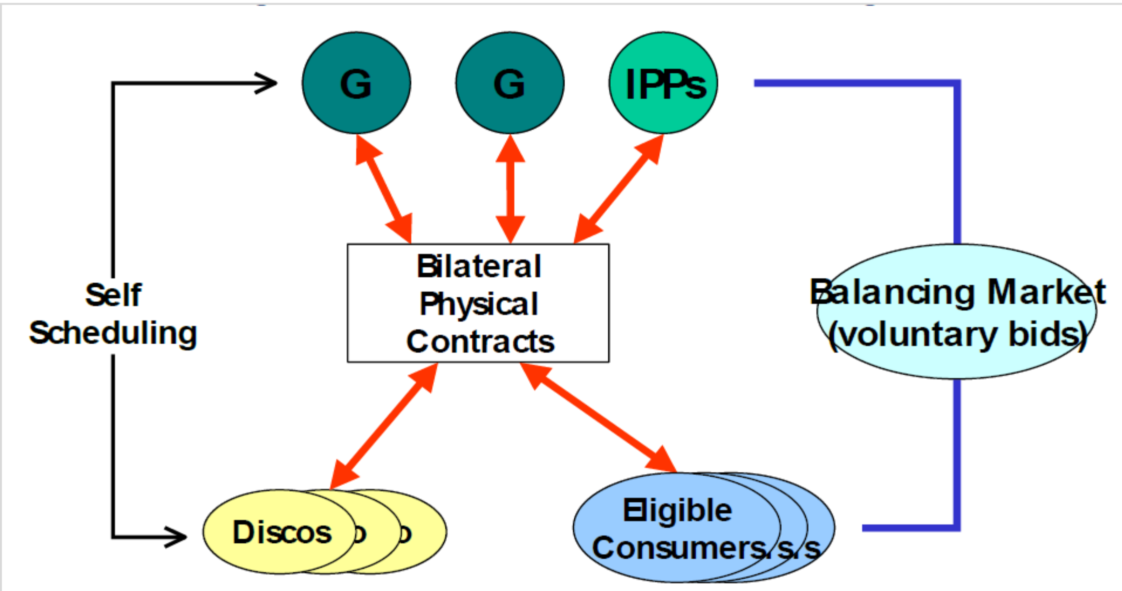
[16] Department of public enterprises: https://www.gov.za/sites/default/files/gcis_document/201910/roadmap-eskom.pdf

Figure 5: Simplified model of an alternative electricity market structure



11.2.4. In the reformed and functioning competitive market outlined in Figure 6, prices are 'discovered' according to the principle of marginal pricing, where underlying marginal cost of production achieves efficient allocation of resources, the market price should be determined by marginal cost of production.

Figure 6: Bilateral contracts Model (multi markets)



Source: CPCS

11.2.5. In functioning markets, where there are a number of competing generators, the ranking of bids will ensure that units with lower costs to serve are dispatched first to meet the load profile of the market and that the market prices are equal to the industry wide marginal costs of production to meet the load types that build-up and characterise the market load profile.

11.3. Annexure C: Compare MYPD4 and MYPDM with Principles incorporated[17]

No.	MYPD4: MYPD methodology without pricing principles	MYPD5: MYPD methodology with pricing principles
1.	The current application of the Revenue Requirement methodology guarantees licensee's revenues thereby encourage inefficient operations as it has been observed with Eskom over the years through the RCA mechanism.	The revised application of the revenue requirement methodology that includes pricing principles will encourage efficient operations by allowing pricing to be setting based on activity based costing prices, unbundling of activities with each service and marginal costing. Under this approach, the RCA will revert to its intended purpose, as an occasional reopener for risk mitigation to address exogenous shocks completely outside of Eskom, or any other service provider's, control, such as a surge in international fuel prices, significant exchange rate fluctuations etc. The regulated entities will be provided with an opportunity to recover efficient costs and make a reasonable return, but no assurance of revenue will be provided in terms of the application of the methodology.
2.	Coal costs were determined based on existing contracts and an average coal price. This has led to recognition of costs that are has not been efficiently incurred. The regulator relied on investigation conducted by other state organs to claw-back inefficient costs. Regardless, serious asymmetry of information remains. Eskom refuse to have power stations audited from an efficiency perspective and only agreed to grid code compliance. Eskom has refused to be regulated for its efficiency under this methodology.	Costs will be allowed based on acceptable industry standards or benchmarks. Transparent benchmarks are a conventional and recognised regulatory alternative to addressing information asymmetry.
3.	There is no section dealing with the shareholder equity injection	There will be a section included to deal on how the regulator will deal with shareholder equity injection.
4.	The unbundling of activities is at Gx, Tx and distribution only	The activity will be unbundled throughout the entire value chain and further unbundling will be at services provided by each activities. The outcome will be

[17] ER No 236 of 06122021, Tanzwana No. NERSA 368-350 - Approval of enhance RfD on principles to be used when determining electricity prices

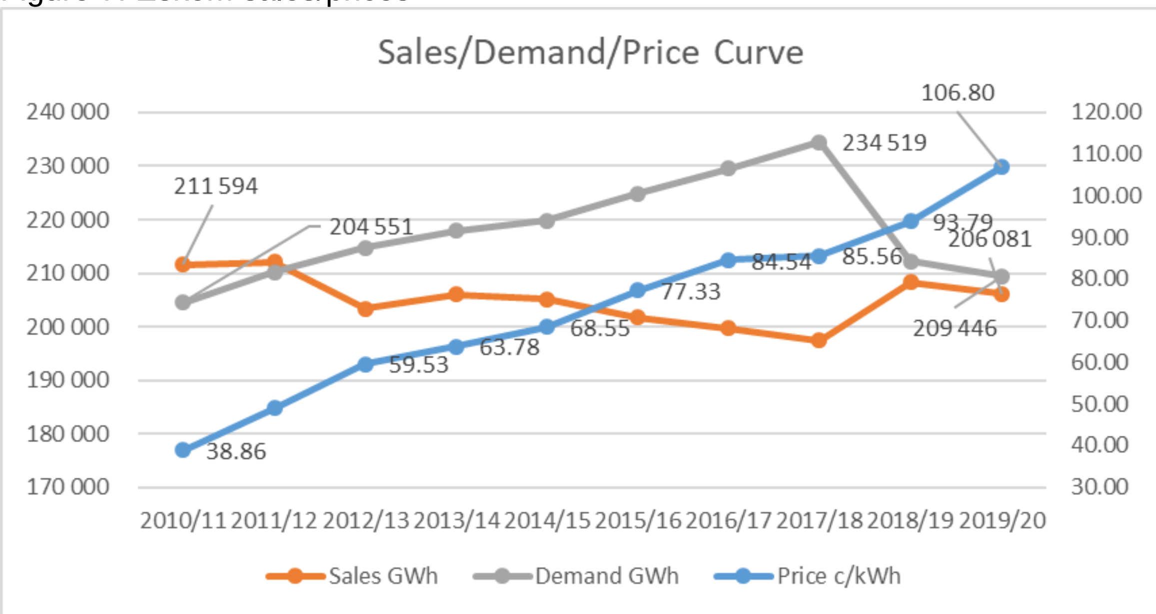
No.	MYPD4: MYPD methodology without pricing principles	MYPD5: MYPD methodology with pricing principles
		truly cost reflective tariffs – in terms of both cost to produce and cost to serve.
5.	The approach does not allow for clear and transparent wheeling as use-of- system tariffs costs are bundled, averaged and opaque.	Allows for clear and transparent wheeling and use-of-system tariffs based on conventional globally applied revenue requirement methodology
6.	There is no differentiation of costs per service provided.	Allows for clear determination of cost of each activity by service eg. Cost of generation by different generation plants and how these translate into true cost to serve and type of use tariffs;
7.	Lack of communication/signalling of appropriate costs of generation. Costs level is too aggregated; there is no breakdown of costs to the level power station.	Communicates appropriate cost of generation and communicates true IPP costs; the accurate signalling of the actual cost to serve will drive behaviours in terms of the appropriate use of electricity
8.	The MYPD4M does not enable competition rather promotes a monopolistic market were distributors buy from one wholesaler.	Creates competition amongst different technologies and amongst different market players with the determination of a trading tariff, reflective of its cost base;
9.	The MYPDM as it is does not respond to the changes happening in the electricity industry and currently lack of transparency and averaging of costs enables inefficient investments on the supply side and disinvestment on the demand side.	The MYPDM that includes the pricing principles prepares South Africa for a fully liberalised electricity industry and promotes efficient investments on the demand and supply side;
10.	There is been proliferation in the number of NPAs under the MYPD4 control period.	Potentially eliminates the need for negotiated price agreements as the tariffs will be aligned with the needs of the various types of use (and subsequent loads) from the demand side;

11.4. Annexure D: Additional commentary on Drivers for Change

11.4.1. **Transformation and unbundling of the Electricity Industry**: In the reformed electricity market, the transmission systems operator will have to act as an unbiased electricity market broker, to promote capital investment within the electricity demand and supply industry and to catalyse energy efficiency and sustainability. Unbundling also allows for the ISO to independently contract with independent power producers and Eskom generation without the conflict of interest, as it currently exists[18] – a discussion of some of the options for a future market structure can be found in Section 11.

11.4.2. With this approach means that as Eskom's declared costs have been increasing, whilst sales have been declining, triggering applications for increased revenues, the electricity prices have been increasing in unprecedented rates (see Figure 7 below). Eskom sales in 2010 were 211 594GWh and 206 572GWh in 2019/20. The wholesale price increased from 38.86c/kWh to 106.90c/kWh over the same period, an increase of 175%.

Figure 7: Eskom sales/prices



11.4.3. **Basic economic infrastructure failing economic development**: The impact of the falling sales against escalating prices does not tell the whole story. One needs to identify where the sales have been forfeited to understand the lose-lose impact for South Africa. As outlined in Table 2 below, Eskom has been losing most of its sales from critical economic

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[18] UCT GSB Power Futures Lab, https://static1.squarespace.com/static/5c1364db45776e7d434895a3/t/5cba0cf9e4966b8949b48e4c/1555696893795/Unbundling+Note_April2019.pdf

sectors, namely productive primary sectors producing the feedstock for industrial/manufacturing sectors beneficiating our natural resources. Whether these be mining companies producing minerals or agri-processing[19] companies using our agricultural resources, South Africa's greatest sources of tradable are derived from the minerals, agricultural and tourism sectors.

Table 2: Eskom sales by sector (2012 – 2021)

Electricity sales per customer category, GWh	2021	2020	2019	2018	2017	2016	2015	2014	2013	2012	(Reduction)/growth in GWh sales, %
Distributors	82 446	85 984	87 236	87 133	89 718	89 591	91 090	91 262	91 386	92 140	-10.5%
Residential	10 949	11 293	11 748	12 302	11 863	11 917	11 586	11 017	10 390	10 522	4.1%
Commercial	9 696	10 486	10 558	10 539	10 339	10 150	9 644	9 605	9 519	9 270	4.6%
Industrial	40 881	45 610	48 717	47 854	48 295	50 150	53 467	54 658	51 675	58 632	-30.3%
Mining	26 991	28 703	28 972	30 235	30 559	30 629	29 988	30 667	31 611	32 617	-17.2%
Agricultural	5 461	5 770	5 796	5 711	5 405	5 733	5 401	5 191	5 193	5 139	6.3%
Rail	1 931	2 600	2 831	3 148	2 849	2 852	3 098	3 125	2 996	3 270	-40.9%
International	13 497	15 189	12 461	15 268	15 093	13 465	12 000	12 378	13 791	13 195	2.3%
TOTAL	**191 852**	**205 635**	**208 319**	**212 190**	**214 121**	**214 487**	**216 274**	**217 903**	**216 561**	**224 785**	**-14.7%**

11.4.4. **Weak price signals drive poor consumer choices**: Different demand profiles require different supply options, which come from different types of generators, ranging from baseload plants, through variable energy sources to various energy storage technologies. Different generation technologies have different costs, not because of inefficiency but because of their design. For example, plants with Plants with high spinning reserve capacity present a very different cost profile to other plants they play a unique role in stabilising the system and require an appropriate pricing approach. Emergency or back-up power for instance, cannot be priced the same way as the normal run-of mill power generation.

11.4.5. **Issues driving Electricity Industry transformation**: In the context of these fundamental issues transforming the Electricity Industry and related shortcomings in a revenue based MYPD methodology, and changing environment, the rationale for this impending overhaul, is drawn from a number of issues that need correcting, including inter alia:

[19] Agri-processing industry is a subset of manufacturing that processes raw materials and intermediate products derived from the agricultural sector.

11.4.5.1. the incompatibility of revenue regulation to the current regulatory environment and a transition to a transparent cost reflective approach;

11.4.5.2. minimising the impact of declining sales on consumers and correctly transferring the sales risk back to the producers;

11.4.5.3. minimising the impact of poor performance on consumers while correcting locating the incentive to improve efficiency with the producers;

11.4.5.4. misalignment between PPAs and the dispatch rules by using market related mechanisms to correct such misalignment;

11.4.5.5. unbundling of the Electricity Industry and calls to facilitate market access;

11.4.5.6. need to facilitate bilateral contracts within clear and equitable market rules that limit abuse of natural monopoly power;

11.4.5.7. development of fair and robust rules that replace the role of Eskom's system operator and Eskom being a single buyer; and Requirement for predictable clear wheeling tariffs.

11.5. Annexure E: Detailed Workbook Structures

11.5.1. Generation

11.5.1.1. There are two generation workbooks. One is intended for use with any generator (including IPPs), whilst the other is Eskom specific. Nevertheless, the information requested is the same in each case. Licensees will be required to submit the information in a prescribe format and any other relevant information.

11.5.1.2. The information requested is at the individual power station level – not at the entity level, for example, total Eskom Generation where the data would be far too aggregated to provide comprehensive insights into the cost base and how it is changing, nor at the generator set level which is considered to be overly burdensome for licensees to provide and may provoke complex analytical issues, although the latter conclusion will be subject to review if necessary.

11.5.1.3. This annexure details format and brief explanation of the various cost categories that should be provided for all regulated entities.

11.5.2. Generation power information

11.5.2.1. The main purpose of requesting this data is to determine a Capacity (MW) that will then be used as a denominator in tariff determination.

Table 3: General Power Station Information

General Power Station information – for each power station
Years commissioned (first to last units), other age-related information
Total installed capacity MW
Total nominal capacity MW
Peak Output MW
Power sent out, GWh (net) Planned Actual
Capacity Utilisation (%) for the previous and current years – originally planned and actual
Availability in year (%) for the previous and current years – originally planned and actual
Heat Rate (MJ/kWh) – other efficiency factors for inclusion in a performance incentive scheme may also be requested. This is being given further consideration and could form part of the stakeholder consultation process

Stakeholder question 1

> Stakeholders are requested to comment on generation PowerStation information as detailed in table 2 above. Total nominal capacity will be used as a denominator in determining the tariff.
>
> a) Is the information sufficient to understand general power station information of each power station?
>
> b) Is the use of nominal capacity as a denominator appropriate in tariff determination?

11.5.3. **Regulatory Asset Base, return and Depreciation**

11.5.3.1. Regulator recognise fixed costs (RAB) to be used in tariff determination. This is calculated by establishing the value of the assets used –regulatory asset base(RAB) – and applying to this a rate of return (ROR) based on the weighted average cost of capital or WACC. The information should be provided for each power station as shown in **Table 3** for each financial year.

Table 4: Regulatory Asset Base (RAB) information

Regulatory Asset Base (RAB) information – for each power station
Value of the RAB at the beginning of the year (R mill)
Value of the RAB at the end of the year (R mill)
Capital expenditure (Capex) in year included in RAB (R mill)
Capital expenditure (Capex) in year not included in RAB (R mill) – if any
Allowed ROR/WACC assumed (%)
Allowed ROR/WACC assumed (R mill)
Depreciation (R mill)

Stakeholder question 2

> Stakeholders are requested on the content of RAB information required from licensees, as shown in Table 3. NERSA is of the view that an evaluation method other than historical costs should be avoided.
>
> a) Will the information be sufficient for NERSA to understand costs related to RAB for tariff determination? If not, what other information could be included?
>
> b) Should a licensee be granted freedom to choose its preferred approach, and what is the most appropriate evaluation approach?

11.5.4. **Primary energy**

11.5.4.1. Table 5 below shows the cost breakdown that should be provided for each power station and for each required year. This information is classified as variable costs and will be included collected and used in tariff determination.

Table 5: Primary Energy Costs

Primary Energy Costs (R mill) – for each power station	
Fuel usage (coal, oil, gas)	Start-up fuel
	Operational fuel
Fuel handling	
Water usage and treatment	
Other (specify and provide breakdown of material items)	

Stakeholder question: 3

Stakeholders are requested to comment on the details and the format of information regarding primary energy required from licensees and the fact that this information is required for each power station.

11.5.5. **Operations and maintenance and other site related costs**

11.5.5.1. This category focuses on operations and maintenance and other site related costs. Table 6 shows the cost breakdown that should be provided for each power station and for each required year. These are variable costs that will assessed and included in the tariff determination.

Table 6: Operations and maintenance and other site related costs – for each power station

Operations and maintenance and other site related costs (R mill) – for each power station	
Operations and maintenance costs - net of capitalisation and other income	Labour
	Contractors
	Materials and supplies
	Other (specify and provide breakdown of material items)
Technology Services	
Environmental Compliance	
Insurance	
Other on-site support (specify and provide breakdown of material items)	

Stakeholder question: 4

Licensees are requested to comment on the format and details contained in table 5 above on relating to operation and maintenance. a) Is the information required on from licensee sufficient and appropriate to have full underrating of the costs and for tariff setting purpose?

11.5.6. **Other support and share of corporate costs**

11.5.6.1. This category of cost is other support and share of corporate costs. **Table 7** below shows the cost breakdown that should be provided for each power station and for each required year.

Table 7: ***Other support and share of corporate costs***

Other support and share of corporate costs – for each power station
Finance
HR
Commercial
Security
Stakeholder management
Board and CEO
Research and Development
Sustainability
Strategic and consultancy costs
Other (Specify and provide breakdown of material items)

Stakeholder question: 5

NERSA requires shared cooperated costs information to understand licensees' operations. a) Stakeholders are requested to comment on details and information relating to the other support and shared costs as detailed in table 6 above. b) Is the information required from licensees sufficient and appropriate for tariff setting purpose? Please provide any other additional information that may be necessary.

11.5.7. **Independent** Transmission System Operator

11.5.7.1. This is a non-financial information required from the transmission operator. The information will be used as a denominator in tariff determination.

Table 8: where appropriate this should be shown as actual/forecast and estimated after adjustment for load shedding / load curtailment / load reduction.

Transmission system - usage and demand data	
Units entering the transmission system	**Units exiting the system**
Eskom Generation (MWh)	Eskom Distribution (MWh)
IPPs - see breakdown (MWh)	Direct sales customers (MWh)
International imports (MWh)	International exports (MWh)
International wheeled units (MWh)	International wheeled units (MWh)
Total (MWh)	**Total (MWh)**
Peak Demand (MVA)	
Time and date of system maximum demand	

Table 9: Required transmission system usage and demand data

Transmission system - usage and demand data	
Units entering the transmission system	**Units exiting the system**
Eskom Generation (MWh)	Eskom Distribution (MWh)
IPPs - see breakdown (MWh)	Direct sales customers (MWh)
International imports (MWh)	International exports (MWh)
International wheeled units (MWh)	International wheeled units (MWh)
Total (MWh)	**Total (MWh)**
Peak Demand (MVA)	
Time and date of system maximum demand	

Table 10: Transmission system

Transmission system - usage and demand data	
Transmission Losses	
Losses (MWh)	Losses percentage (of units entering the system) - (%)

Table 11: IPP information

IPP Information – each IPP
Name and location
Transmission or distribution connected
Connection voltage
Date commissioned
Total installed capacity MW
Total nominal capacity MW

Purchaser of output		
For the previous, current and appropriate MYPD years	Actual or expected output (MWhs)	
	Purchase cost (if selling to the ITSMO) - not including ancillary services (R mill)	
Provides paid-for ancillary services?		
Purchase costs for ancillary services (if any) (R mill)		

Stakeholder question: 6

a) Based on the above information requirement, do you foresee any risk of the information requested being unavailable or insufficient or not currently being collected in this form or to this detail?
b) Should the IPP information be part of the TSO or should it be captured with Eskom Generation information?
c) How should the fixed costs be allocated to the different customer group, should they be shared equally or be based on customer's level consumed capacity?
d) Transmission costs are largely fixed in that they are not linked to what is produced. How can the charges associated with these fixed costs be allocated, (e.g. R/MVA, R/MW, and R/km)?

11.5.8. **Transmission Network Operator**

11.5.8.1. The costs associated with Transmission infrastructure should be separated along the zones and voltage levels as defined in Table 10 above. The components to be costed relate to:

11.5.8.1.1. Transmission lines

11.5.8.1.2. Transmission substations

11.5.8.2. The zones define the distances between the majority of generation facilities and the different load centres. This is still applicable in the medium term as the majority of generation is still concentrated in Mpumalanga, Limpopo and Cape Town.

11.5.8.3. In the long term however this picture will change as more RE plants are added to the energy mix and generation is more distributed across the country. Categories along the voltage level may become more appropriate then.

11.5.8.4. With reference to lines "wires" , there should be a typical cost associated with a transmission line at a particular voltage level and a particular length. Benchmarks of typical costs at different zones will be done to ensure efficiency of these costs.

11.5.8.5. With regards to transmission substation costs, the additional cost associated with stepping down of voltages to be indicated as such in order for the cost at each voltage level can be attained. Benchmarks of typical costs at different zones will be done to ensure efficiency of these costs.

Table 12: Transmission network operator – demand zone and voltage level disaggregation

Network Operator costs disaggregation by demand zone and voltage level. Transmission Loss Factors are also required for each.	
Less than 300 km	765kV
	533kV DC (monopolar)
	400kV
	275kV
	220kV
	132kV
Between 300 and 600 km	765kV
	533kV DC (monopolar)
	400kV
	275kV
	220kV
	132kV
Between 600 and 900 km	765kV
	533kV DC (monopolar)
	400kV
	275kV
	220kV
	132kV
Over 900 km	765kV
	533kV DC (monopolar)
	400kV
	275kV
	220kV
	132kV
Other	

11.5.8.6. The following sections provide a detailed explanation of the various cost categories and other information that should be provided for the transmission network operator in total and split zonally, and across voltage levels for each of the required years, as previously explained. The cost can be broken up in the following categories;

11.5.8.6.1. Regulated Asset Base (RAB), Return and Depreciation

11.5.8.6.2. Taxes and Levies

11.5.8.6.3. Insurance costs

11.5.8.6.4. Operations and Maintenance and Other costs

11.5.8.6.5. Other Support costs and Tx share of corporate costs

11.5.8.6.6. Ancillary Services Costs

Table 13: Transmission network operator – RAB information

Regulatory Asset Base (RAB) information – Transmission Network Operator: Disaggregated by zone and voltage
Value of the RAB at the beginning of the year (R mill)
Value of the RAB at the end of the year (R mill)
Capital expenditure (Capex) in year included in RAB (R mill)
Capital expenditure (Capex) in year not included in RAB (R mill) – if any
Allowed ROR/WACC assumed (%)
Allowed ROR/WACC assumed (R mill)
Depreciation (R mill)

Stakeholder question: 7

Stakeholder Questions

a) What is the most appropriate way of valuing asset value?

b) How can the efficiency of capital investment be taken into account?

c) Is there value in categorising the Tx infrastructure according to zones as well as voltage levels, is it practical or desirable?

d) How should the fixed cost be allocated to the different customer group, should they be shared equally or be based on customer's level consumed capacity?

e) Transmission costs are largely fixed in that they are not link to what is produced. How can the charges associated with these fixed costs be allocated, (e.g. R/MVA, R/MW, R/km)?

Table 14: Transmission network operator –and operations and maintenance other costs information.

Operations and maintenance and other costs (R mill)	
Operations and maintenance costs - net of capitalisation and other income	Labour
	Contractors
	Materials and supplies
	Other (specify and provide breakdown of material items)
Insurance	
Taxes and levies	

Stakeholder question: 9

a) How can the efficiency of operation and maintenance cost be taken into account.

11.5.9. **Other support and share of corporate costs**

11.5.10. Table 15 below shows the cost breakdown that should be provided for both the transmission network operator as a whole and also disaggregated across zones and voltages for each required year.

Table 15 : Transmission network operator – other support and share of corporate costs information

Other support and share of corporate costs
Finance
HR
Commercial
Security
Stakeholder management
Board and CEO
Research and Development
Sustainability
Strategic and consultancy costs
Other (Specify and provide breakdown of material items)

11.5.11. Expenditure to provide ancillary services

11.5.11.1. Finally, for the transmission network operator, capital and operating expenditure in respect of issues that may alternatively have been resolved by procuring ancillary services from generation and demand should be identified again for both the transmission network operator as a whole and also disaggregated across zones and voltages for each required year. The cost associated with ancillary services must be separated along the lines of the type of ancillary services as defined in the Grid Codes as well as all other relevant internal System Operator guideline documents. The ancillary service outlined in the data request template includes the following;

11.5.11.1.1. Black start and islanding

11.5.11.1.2. Instantaneous reserve

11.5.11.1.3. Regulation reserve

11.5.11.1.4. Ten-minute reserve

11.5.11.1.5. Emergency reserve

11.5.11.1.6. Supplemental reserve

11.5.11.1.7. Reactive power / Voltage control

11.5.11.1.8. Constrained generation

11.5.11.1.9. Control area services

Stakeholder question: 10

a) Can ancillary services be apportioned to a particular consumer group? b) If yes above, how should ancillary services be charged to different customer groups? Should these cost be socialised to the entire customer base? Which customer group creates the need for ancillary services? c) Does the list above covering all currently deployed ancillary services? d) Is it likely that there may be additional types of ancillary services that are not included in the list above that would need to be catered for in the future?

11.5.12. **Independent Transmission System and Market Operator (ITSMO)**

The sections below examine the various parts of both the internal and external costs.

11.5.12.1. Internal ITSMO Costs – Depreciation and Margin

11.5.12.1.1. Unlike the elements of the value chain examined so far, the ITSMO is likely to have limited assets. Nevertheless, there may be some (potentially items such as capitalised IT costs) that can be quite substantial. Thus an understanding of these will be important in order to determine depreciation costs that need to be recovered. Hence, the items shown in Table 16 should be provided for both the Independent System Operator and Market Operator separately for each relevant year.

Table 16: ITSMO – RAB information

Regulatory Asset Base (RAB) information – ITSMO: Disaggregated between system and market operator
Value of the RAB at the beginning of the year (R mill)
Value of the RAB at the end of the year (R mill)
Capital expenditure (Capex) in year included in RAB (R mill)
Capital expenditure (Capex) in year not included in RAB (R mill) – if any
Depreciation (R mill)

11.5.12.1.2. The system and market operators are important facilitators of the electricity industry and it is vital that the activities that they undertake must be unbiased. They also have a fairly limited need for capital investment which can probably be met through loans rather than equity. In such circumstances it is questionable whether there is a need for these functions to be profit making and it may be more appropriate for the activity to be on a non-profit making basis (taking into account of the need to service any loans that may have been entered into).

Table 17: ITSMO – Allowed margin: system and market operator

Allowed Margin information – Disaggregated between system and market operator
Allowed margin assumed (%)
Allowed margin assumed (R mill)

Stakeholder question: 11

Should the System and Market operator be allowed a profit/margin?

11.5.12.1.3. The next category is operations and maintenance and other costs. Figure 8-15 and Table 18 show the cost breakdown that should be provided for the ITSMO, separated between the system and market operators, and for some of the functions within them for each required year.

Table 18: ITSMO – operations and maintenance and other costs: system and market operator

Operations and maintenance and other costs (R mill)	
Operations and maintenance costs	Labour
	Contractors
	IT
	Other (specify and provide breakdown of material items)
Insurance	
Taxes and levies	

11.5.12.2. Internal ITSMO Costs – Operations and maintenance and other costs

11.5.12.2.1. Table 19: ITSMO – Further breakdown of operating and maintenance and other costs: system and market operator.

Table 20: Further breakdown of operating and maintenance and other costs

Further breakdown of operating and maintenance and other costs (R mill)			
Independent System Operator		Market Operator	
System Operations	Labour Contractors IT Costs Other Costs	Trading Platform	Labour Contractors IT Costs Other Costs
Transmission Planning	Labour Contractors IT Costs Other Costs	Procurement/ Sales	Labour Contractors IT Costs Other Costs
Code and Practice Management	Labour Contractors IT Costs Other Costs	Other	Labour Contractors IT Costs Other Costs
Other	Labour Contractors IT Costs Other Costs		

11.5.12.3. Internal ITSMO Costs – Other support and share of corporate costs

11.5.12.4. The next category is other support and share of corporate costs. Table 21 shows the cost breakdown that should be provided for the ITSMO separated between the system and market operators for each required year.

Table 21: ITSMO – other support and share of corporate costs information

Other support and share of corporate costs
Finance
HR
Commercial
Security
Stakeholder management
Board and CEO
Research and Development
Sustainability
Strategic and consultancy costs
Other (Specify and provide breakdown of material items)

11.5.12.5. External ITSMO Costs - Purchasing of electricity and related services

11.5.12.5.1. The external ITSMO costs are those that result from the purchasing of electricity and related services. As there is an ongoing consultation process regarding the Electricity Regulation Amendment Bill and uncertainty about the enduring market design and transitional steps ahead of its complete implementation, it is not possible at this stage to wholly define which cost categories are applicable to the Independent System Operator and Market Operator (and, indeed, the central purchasing agency). As a result, the data collection process is being designed to be as flexible as possible to deal with as many of the alternative outcomes as possible.

11.5.12.5.2. Table 22 shows the cost categories for data collection for both the Independent System Operator and Market Operator, as appropriate. The regulatory treatment for these costs will be dependent on the extent to which they may have been subject to scrutiny at a different part of the value chain, the need to avoid any double counting in allowable costs, and possible incentive schemes to encourage overall system efficiency. These costs will be unbundled as separate costs from transmission and they require their own separate tariffs.

Table 22: ITSMO – external cost information

External ITSMO Costs - Purchasing of electricity and related services (R mi categories	
Electricity purchased for resale	Eskom
	Legacy IPPs
	Other IPPs
	International
Balancing costs	Eskom
	IPPs
	International
Congestion costs	Eskom
	IPPs
	International
	Other Costs
Hedging and financial instrument costs (if any)	
Purchasing of Ancillary Services	Eskom
	IPPs
	International
	Other (including battery and other storag demand response)

Table 23 shows the further breakdown in ancillary cost purchases, according to each individual service, that will also be needed.

Table 23: Breakdown of Ancillary Services

Further breakdown of Ancillary Services Cost (R mill)				
Black start and islanding	Eskom	IPPs	International	Other (including battery and other storage, and demand response)
Instantaneous Reserve	Eskom	IPPs	International	Other (including battery and other storage, and demand response)
Regulation Reserve	Eskom	IPPs	International	Other (including battery and other storage, and demand response)
Ten-minute Reserve	Eskom	IPPs	International	Other (including battery and other storage, and demand response)
Emergency Reserve	Eskom	IPPs	International	Other (including battery and other storage, and demand response)
Supplemental Reserve	Eskom	IPPs	International	Other (including battery and other storage, and demand response)
Reactive power/Voltage control	Eskom	IPPs	International	Other (including battery and other storage, and demand response)
Constrained Generation	Eskom	IPPs	International	Other (including battery and other storage, and demand response)
Control area services	Eskom	IPPs	International	Other (including battery and other storage, and demand response)
Other	Eskom	IPPs	International	Other (including battery and other storage, and demand response)

Stakeholder question: 12

a) Based on the above information requirement, do you foresee any risk of the information requested being unavailable or insufficient or not currently being collected in this form or to this detail? b) What costs is a Market Operator likely to have? Is it your view that the future Electricity Industry structure will have a Market Operator separated from the Independent System Operator?

11.5.13. Central Purchasing Agency (CPA)

11.5.13.1. As with the previous elements of the value chain, detailed cost information is required for the CPA to assess the efficiency and prudency of the costs and to support the assessment and approval of the charges necessary to meet those costs. The CPA costs, as with the ITSMO and for the same reasons, are separated between internal costs and those resulting from the procurement of electricity and related services. The sections below examine the various parts of both the internal and external costs.

11.5.14. Internal CPA Costs – Depreciation and Margin

11.5.14.1. Similarly, to the ITSMO, the CPA is likely to have limited assets. Nevertheless, there may be some (potentially items such as capitalised IT costs) which may be quite substantial and thus an understanding of these is important in order to determine depreciation costs that need to be recovered. Hence, the items shown in Table 24 should be provided for both the Independent System Operator and Market Operator separately for each relevant year.

Table 24: CPA – RAB information

Regulatory Asset Base (RAB) information - CPA
Value of the RAB at the beginning of the year (R mill)
Value of the RAB at the end of the year (R mill)
Capital expenditure (Capex) in year included in RAB (R mill)
Capital expenditure (Capex) in year not included in RAB (R mill) – if any
Depreciation (R mill)

Table 25: CPA – Allowed margin: system and market operator

Allowed Margin information – CPA
Allowed margin assumed (%)
Allowed margin assumed (R mill)

11.5.15.**Internal CPA Costs – Operations and maintenance and** other costs

11.5.15.1. The next category is operations and maintenance and other costs, including any planning resources, should the CPA have a planning division within it. Figure 8-22 shows the cost breakdown that should be provided for the CPA for each required year.

Table 26:CPA – operations and maintenance and other costs

Operations and maintenance and other costs (R mill)	
Operations and maintenance costs	Labour
	Contractors
	IT
	Other (specify and provide breakdown of material items)
Insurance	
Taxes and levies	

11.5.16.**Internal CPA Costs – Other support and share of** corporate costs

11.5.16.1. The next category is other support and share of corporate costs. Table 27 shows the cost breakdown that should be provided for the CPA for each required year.

Table 27: CPA – other support and share of corporate costs information

Other support and share of corporate costs
Finance
HR
Commercial
Security
Stakeholder management
Board and CEO
Research and Development
Sustainability
Strategic and consultancy costs
Other (Specify and provide breakdown of material items)

Table 28: External CPA Cost

External CPA Costs - Purchasing of electricity and related services (R mill): Cost categories	
Electricity purchased for resale	Eskom
	Legacy IPP's
	Other IPP's
	International
Purchasing of Ancillary Services	Eskom
	IPP's
	International
	Other (including battery and other storage, and demand response)

11.5.16.2. Table 29 shows the further breakdown in ancillary cost purchases, according to each individual service, that will also be needed.

Table 29: CPA – external cost information, further breakdown

Further breakdown of Ancillary Services Cost (R mill)				
Black start and islanding	Eskom	IPPs	International	Other (including battery and other storage, and demand response)
Instantaneous Reserve	Eskom	IPPs	International	Other (including battery and other storage, and demand response)
Regulation Reserve	Eskom	IPPs	International	Other (including battery and other storage, and demand response)
Ten-minute Reserve	Eskom	IPPs	International	Other (including battery and other storage, and demand response)
Emergency Reserve	Eskom	IPPs	International	Other (including battery and other storage, and demand response)
Supplemental Reserve	Eskom	IPPs	International	Other (including battery and other storage, and demand response)

Further breakdown of Ancillary Services Cost (R mill)				
Reactive power/Voltage control	Eskom	IPPs	International	Other (including battery and other storage, and demand response)
Constrained Generation	Eskom	IPPs	International	Other (including battery and other storage, and demand response)
Control area services	Eskom	IPPs	International	Other (including battery and other storage, and demand response)
Other	Eskom	IPPs	International	Other (including battery and other storage, and demand response)

Stakeholder question: 13

Stakeholder Questions

a) Based on the above information requirement, do you foresee any risk of the information requested being unavailable or insufficient or not currently being collected in this form or to this detail?

b) Are there other ancillary services that would be required in the near future that are not listed above?

11.5.17. Distribution – Wires

11.5.17.1. At the distribution level, there is clearly a need, as instructed by section 13(3) of Act to separate infrastructure from trading. At the municipal level, there has also been a third and important aspect, driven section 229 of SA Constitution that allowing, municipalities to levy surcharges on services provided in their areas. Clearly, these must be dealt with differently and above board.

11.5.17.2. A workbook has been designed for the collection of data about what is referred to here as "distribution wires" activities. This means the activities of planning, installing and operating distribution networks (defined as most 132 kV and lower voltage systems used to distribute electricity to end-use customers and sometimes to other licensees). The provider of “distribution – wire” activities is often called the distribution network operator. At present, these network costs are amalgamated with those of the trading activities, both within Eskom Distribution and the electricity functions of the municipalities.

Stakeholder question: 14

a) Should municipal distribution network charges that are different from Eskom network tariffs be allowed? b) What other options for designing network tariffs should be considered by NERSA? *c)* Stakeholders are requested to comment on the proposed approach to recovering the cost of distribution network services from traders.

Table 30: Distribution network operator –further costs breakdowns

Distribution Network Operator Further Cost Breakdowns	
Cost by voltage level – split as shown	***Cost by customer category***
132kV ≥ 66kV & 132kV 500V & < 66kV < 500V	For each category split into periods (daily, seasonal etc - as appropriate). This is expected to range from one to six according to category.
Distribution Losses	
Planned or actual total losses (%)	
Distribution Loss Factors	
Technical loss factors for the following voltage levels – at 132kV, from 66kV to 132kV, from 500V to 66kV, and below 500V	Non-technical losses – proportion for each customer category

Stakeholder question: 15

Stakeholders are requested to comment on how the energy losses in the distribution system should be determined?

11.5.18.Regulatory Asset Base, return and Depreciation

11.5.18.1. Access to the distribution network will be allowed in order to facilitate the trading of energy. This will be subject to NERSA approval to sell and signing the distribution network service provider's agreement.

Stakeholder question: 16

Stakeholders are requested to comment on the principles to be considered for the treatment of existing wheeling arrangements.

Table 31: Distribution network operator – RAB information

Regulatory Asset Base (RAB) information – Distribution (wires) disaggregated between voltages and customer categories
Value of the RAB at the beginning of the year (R mill)
Value of the RAB at the end of the year (R mill)
Capital expenditure (Capex) in year included in RAB (R mill)
Capital expenditure (Capex) in year not included in RAB (R mill) – if any
Allowed ROR/WACC assumed (%)
Allowed ROR/WACC assumed (R mill)
Depreciation (R mill)

Stakeholder question: 17

a) Should licensees be given freedom to choose a method of valuing RAB or should NERSA prescribe an approach? b) Should a prescribed approach be preferred; which approach is the most practical for implementation in South Africa.

11.5.19. Operations and maintenance and other costs

11.5.19.1. Table 32 shows the cost breakdown for operations and maintenance and other costs that should be provided for both the distribution network operator as a whole and also disaggregated across voltages and customer categories for each required year.

Table 32: Distribution network operator – operations and maintenance and other costs information

Operations and maintenance and other costs (R mill) disaggregated by voltage level and customer category	
Operations and maintenance costs - net of capitalisation and other income	Labour
	Contractors
	Materials and supplies
	Other (specify and provide breakdown of material items)
Metering costs	Labour
	Contractors
	Other (specify and provide breakdown of material items)
Customer service costs	Labour
	Contractors
	Other (specify and provide breakdown of material items)
Insurance costs	
Taxes and Levies	

Stakeholder question: 18

Stakeholders are requested to comment on the appropriateness of the cost of operations and maintenance of the distribution networks.

11.5.20. Other support and share of corporate costs

11.5.20.1. Table 33 shows the cost breakdown for other support and shared corporate costs that should be provided for both the distribution network operator as a whole and also disaggregated across voltages and customer categories for each required year.

Other support and share of corporate costs (R mill)
Finance
HR
Commercial
Security
Stakeholder management
Board and CEO
Research and Development
Sustainability
Strategic and consultancy costs
Other (Specify and provide breakdown of material items)

Table 33: Distribution network operator – other support and share of corporate costs information

Stakeholder question: 19

Do you believe that the operating cost categories for other support and share of the corporate division listed above are adequate?

11.5.21. Distribution Trading

11.5.21.1. It is important that the information provided in respect of trading activities is of sufficient granularity so that these can be properly assessed and, where appropriate, benchmarked. To achieve this trading costs must be disaggregated into the appropriate number of cost categories (and where there are separate time periods within them into those time periods) as indicated in Table 34 below.

Table 34: Trading – Cost breakdown by customer category

Further cost breakdowns	
Cost by customer category	
Category 1	
Periods (daily, seasonal etc - as appropriate for category - add more periods if necessary)	1
	2
	3
	4
	5
	6
Add required number of customer categories	

Stakeholder Question: 20

a) Stakeholders are requested to advise if the required information in respect of the trading activities sufficient to carry the required analysis;

b) Stakeholders are requested to clearly identify the costs related to trading activities and separate those costs from the distribution activities.

11.5.22. Depreciation and Margin

11.5.22.1. Some elements of the electricity value chain have substantial assets and the allowable profit or margin permitted by regulation tends to be determined by this i.e., it is calculated based on the WACC and the RAB. However other elements of the chain have a much more limited need for such assets. Trading falls into the latter category. Nevertheless, there may be some capital items (potential items are capitalised IT costs and, in some cases, some metering costs) which may be quite substantial and thus an understanding of these is important in order to determine any depreciation costs that need to be recovered. The items shown in Table 35 should be provided for trading for each relevant year.

Regulatory Asset Base (RAB) information – Trading: Disaggregated by customer category
Value of the RAB at the beginning of the year (R mill)
Value of the RAB at the end of the year (R mill)
Capital expenditure (Capex) in year included in RAB (R mill)
Capital expenditure (Capex) in year not included in RAB (R mill) – if any
Depreciation (R mill)

Table 35: Trading – RAB information

Stakeholder Question: 21

a) Should NERSA set the trading margin or leave it to the market to decide? Or should it set the tariff only if there is no competition?

b) What would be the denominator to translate the costs into a tariff in order to come up with the margin?

Allowed Margin information – Trading: Disaggregated by customer category
Allowed margin assumed (%)
Allowed margin assumed (R mill)

Table 36: Trading – Allowed margin

Stakeholder Question: 22

a) Since that trading is not asset based but rather knowledge based, can the financial assets (i.e. IT systems, meters, inventory, bad debts) be used to determine the margin?

b) How should the profit associated with trading be determined?

c) Should traders be owning the infrastructure they are trading on?

d) Should licensees be given freedom to choose a method of valuing RAB or should NERSA prescribe an approach?

e) Should a prescribed approach be preferred, which approach is the most practical for implementation in South Africa?

11.5.23. Operations and maintenance and other costs

11.5.23.1. The next category is operations and maintenance and other costs. Table 37 below shows the cost breakdown that should be provided for both the trader as a whole and also disaggregated across customer categories for each required year.

Operations and maintenance and other costs (R mill) disaggregated by customer category	
Metering costs	Labour
	Contractors
	Other (specify and provide breakdown of material items)
Billing and vending costs	Labour
	Contractors
	Other (specify and provide

	breakdown of material items)
Other customer service costs	Labour
	Contractors
	Other (specify and provide breakdown of material items)
Marketing costs	
Bad Debts	
Insurance costs	
Taxes and Levies	

Table 37: Trading – operations and maintenance and other costs

Stakeholder Question: 23

Since trading is not asset based but rather knowledge based; a) Should the financial assets (i.e. IT systems, meters, inventory, bad debts) be used to determine the margin? b) How should the profit associated with trading be determined? c) What will be an allowable cost if costs associated with trading are allowed (i.e. bad debts)? d) Is it a good incentive for paying customers to be penalised for the rest of the non-paying customers?

11.5.24. Other support and share of corporate costs

11.5.24.1. Table 38 below shows the other support and share of corporate costs breakdown that should be provided for both the trader as a whole and also disaggregated across customer categories for each required year.

Other support and share of corporate costs (R mill)
Finance
HR
Commercial
Security
Stakeholder management
Board and CEO

Research and Development
Sustainability
Strategic and consultancy costs
Other (Specify and provide breakdown of material items)

Table 38: Trading – other support and share of corporate costs

Stakeholder Question: 24

a) What are the unique costs related to trading? For example, hedging and (forward prices) long-term prices with generators. Should the cost of hedging be recognised?

11.6. Annexure F: Various tariffs within the value chain

11.6.1. Each business activity across the electricity value chain will have its own individual tariffs that are based on its fixed costs, variable costs and ancillary service costs. Consumer tariffs will be sum of Gx, Tx-system operations, Tx-market operations, ancillary service costs; Dx wires Dx trading, surcharges and or less any subsidies. In a way, consumers will only pay for the costs of service they received, which is a fair and just practice. The tariffs at each business will be categorised in terms of single-part, two-part or three-part tariffs. The costs that will be converted into tariffs at each business will be split in terms of variable and fixed costs. Tariff determination at Gx, Tx and Dx will be different due to factors that drive business activities at each point of the value chain.

11.6.2. Transmission costs will include ancillary service costs that enables transmission of electric power from generators to consumers to maintain reliable operations of the interconnected transmission system. However there is a need to validated which part of the ancillary costs can be socialised. Users of electricity shall pay for all Ancillary Services provided by the traders during each billing period.

11.6.3. Fixed and Variable costs

11.6.3.1. **Fixed costs:** include equipment, land, financing, project management, grid connections, construction of the power plant (CAPEX) and salaries. These costs are generally regarded as 'sunk costs' because once the plant is erected and fixed costs are incurred, they do not change with the level of production. In addition, fixed charges relating to the network connection will be apportioned based on the user's consumption or a determined ratio because those who use more electricity should not pay the same rate as those who use less

.

11.6.3.2. **Variable costs** are costs made of fuel cost, operation and maintenance expenses and carbon dioxide emission charges or levies. Variable costs only play a role when it is necessary to decide whether to use an existing plant to produce electricity or not. Fixed costs are irrelevant to this production decision because they are incurred regardless of the level of production.

Stakeholder question: 25

Based on the split of costs between variable, fixed and classification, stakeholders are requested to comment on the following:

a) Provide your own views on NERSA's list of the classification of the costs into fixed and variable.
b) How to split of fixed costs or allocation of fixed costs to customers based on consumption?
c) Under transmission costs comment on which portion of an ancillary service cost can be socialised (out of pocket costs) and which portion can be carried by customers

11.6.4. Generation tariff determination

11.6.4.1. Generator pricing structures must reflect the generator is cost of supply or alternatively any approved PPA. Generator pricing structure can consist of the following; Capacity, energy and ancillary service charges. Generator pricing structures must not hinder efficient and least cost dispatch of the generating units. The tariff will be either a single part, two part or three-part tariff.

11.6.4.2. In South African large number of customers are mostly served by generating facilities that are often located in isolated areas, far from the point customers who consume electricity. These generating facilities are largely costs driven for them to be operational. The economics of running a power station is entail fixed and variable costs. The determination of fixed costs is mostly relatively straightforward whereas the variable cost of power generation will depends on the amount of electricity produced.

11.6.5. Various tariffs within the value chain

11.6.5.1. The single part tariff is a fixed rate per unit of energy consumed. It is the easiest tariff to compute. Over both the fixed costs as well as the variable (energy) cost at a certain (normative) generation level. A two-part tariff is a form of price whereby consumers are charged for both fixed cost and consumption which relate to variable costs. Therefore, the two-part tariff will be based on fixed cost and variable costs divided by the MWh produced. The single rate will be based on fixed costs and MWh produced whereas the two-part tariff will be fixed costs plus variable cost and MWh produced. This implies that there will be only a two-tariff structure at generation, which is single and two-part tariff structure.

11.6.5.2. The electricity power industry entails the Generation, Transmission, Distribution and Trading of electric power to the public and industry. The electricity energy value chain includes all activities necessary for the production, distribution and consumption of electrical energy. In general terms, energy generators at various generation points, sell the produced electricity to transmission, transmission sell to distribution and in turn, distributors sell to consumers. Such consumers are classified and categorised according to their consumption levels.

11.6.5.3. The Generation part of the value chain is considered the starting point of the buying and selling (trading) of electricity within the Electricity Supply Industry (ESI). At this point, electricity is produced and a Generation Tariff[20] will be set based on costs incurred at Generation and become a determinant factor in determining the Transmission Prices, as Transmission will be buying from Generation.

11.6.5.4. Following are formulae to determine and allocate costs using various tariff structure at Gx, Tx and Dx:

11.6.5.4.1. A single part tariff is a fixed rate per unit of energy consumed.It is the easiest tariff to compute. Over the fixed cost and variable (energy) costs at a certain (normative) generation level. A two-part tariff is a form of price whereby consumers are charged for both the fixed costs and consumption, which relate to variable costs. Therefore, the two-part tariff will be based on fixed cost and variable costs divided by the capacity. In generation, single rate will be based on fixed costs and generation capacity and two-part tariff will be fixed costs plus variable costs divided capacity installed/ nominal capacity. This implies that at generation there will only be a two-tariff and single part tariff structure.

11.6.5.4.2. The electricity power industry entails the Generation, Transmission, Distribution and Trading of electric power to the public and industry. The electricity energy value chain includes all activities necessary for the

[20] $Generation\ Tariff = \frac{Total\ Generation\ Costs}{Operating\ Capacity}$

production, distribution and consumption of electrical energy.

11.6.5.4.3. The following formulae will be used to determine and allocate costs using various tariff structure at Gx, Tx and Dx:

$$Gx\ single\ part\ traiff: \frac{\Sigma\ Fixed\ and\ Variable\ costs}{\Sigma KWh\ in\ capacity}$$

$$Gx\ Two\ part\ tariff: a)\frac{R}{KWh} = \frac{\Sigma\ variable\ costs}{\Sigma\ KWh\ Produced}\ and\ b) R/KVA = \frac{\Sigma\ Fixed\ costs}{\Sigma\ Installed\ capacity}$$

$$Transmission\ system\ ops\ (single\ tariff\ R/kVA/KM) = \frac{\Sigma\ Total\ costs(fixed + Variable)}{KVA/\Sigma KMlines}$$

11.6.5.4.4. This formula is in respect of distance based transmission charges but if the consideration is for a single unitary transmission tariff, then the denominator will only be KVA

$$Transmissiosn\ Market\ ops\ R/KVA = \frac{\Sigma\ Total\ cost(fixed + variable)}{\Sigma\ KVA}$$

$$Distribution\ wires\ R/KVA = \frac{\Sigma\ Total\ costs(fixed + variable)}{\Sigma_{\mathrm{k}} KVA}$$

$$Distribution\ trading\ single\ tarif: R/KWh = \frac{\Sigma_{\mathrm{k}} Total\ costs(fix + variable + cutomer\ servising\ costs)}{\Sigma KWh\ Sold}$$

$$Distribution\ trading\ two\ part\ tarif: \frac{R(\ Variable\ costs)}{KWh} + \frac{R(fixed\ costs)}{total\ number\ of\ customers}$$

$$Part\ a: R/KWh := \frac{\Sigma_{\mathrm{k}} Total\ costs\ variable}{\Sigma KWh\ consumed}$$

$$Part\ b: R/customer := \frac{\Sigma\ fixed + customer\ servicing\ costs}{\Sigma\ total\ number\ of\ customer}$$

$$Distribution\ trading\ three\ part\ tarif =$$

$$\frac{R(variable\ costs)}{KWh} + \frac{R(fixed\ costs)}{KVA} + \frac{R(customer\ servicing\ costs)}{customer}$$

$$Part\ a: R/KWh := \frac{\Sigma\ Total\ costs\ variable}{\Sigma KWh\ consumed}$$

$$Part\ b: \frac{\frac{R}{KWh}}{}annum := \frac{\Sigma\ Total\ fixed\ costs}{\Sigma KVA\ cinstalled}$$

$$Part\ c: R/customers := \frac{\Sigma\ \ customer\ servicing\ costs}{\Sigma\ total\ number\ of\ customers\ enjoying\ the\ service}$$

11.6.6. The value of rates to be charged can be elaborated as follows:

11.6.6.1. **Energy payments:** The purchaser shall pay energy charges for electricity sold and purchased by the buyer for the period under review. This is the variable part of a two-part tariff or, in the case of a single-tariff structure, it represents the tariff.

11.6.6.2. **Start-up payments:** Traders shall ensure that start-up costs are included in tariff determination for the seller to recover its full costs of supply. It depends on the number of start-ups; therefore, it could potentially be customer-specific if the frequency of start-up is due to certain customer requests/operations. In essence, this cost can either be socialised or charged to specific customer groups. Therefore, this should be included in the fixed part of a two-part tariff.

11.6.6.3. **Ancillary service payments:** The purchaser will be required to pay for the ancillary service costs incurred by the trader. This is part of the fixed charge – socialised as part of the transmission charge.

11.6.6.4. **Use of system charges:** The buyer will be required to reimburse the seller for the use of system charges in terms of distribution and/or transmission agreement. The actual charges should be non-discriminatory and should be based entirely on published transmission and distribution tariffs.

11.6.6.5. **Carbon tax:** Generators will recover carbon tax charges as determined by the National Treasury. These are variable costs linked to a specific generator.

11.6.6.6. **Metering costs:** The trader will ensure costs for appointing a metering certifier, and the user shall be liable for meter bridging or improper performance of the meter cased. This could either be a customer-specific cost or linked to the variable part of the trader's tariff.

11.6.6.7. Tariffs will be set in a multi-year fashion and varied only once based on an agreed formula, with the exception being for those generators that are fuel-based, whose variable part of the tariff could be varied more frequently, even as frequent as monthly.

11.6.6.8. **Standby costs:** If the system operator has requested a particular generator to be on standby (cold or warm start), that generator, as in the case with a generator providing ancillary services, has to have its fixed costs reimbursed, and associated costs will be included in the fixed charges associated with systems operation and be socialised. However, there must be a clear process that will identify the need and the selection of those providing the service.

11.6.6.9. Tariffs will be reviewed quarterly in arrears. A station dispatched in the quarter would have been metered, and the system operator would have identified costs.

Stakeholder question: 26

a) How should NERSA deal with cold-reserved plants and ancillary service costs?

b) How should NERSA work out the tariff when a plant is on call reserve?

c) There are plants that have interlinked costs such as cost of recharging in the storage facilities. How should NERSA deal with such costs?

d) In the Gx, Tx and Dx tariffing how should NERSA deal with wheeling charges.

e) Transmission is composed of system and market operation. How should NERSA set a transmission tariff to achieve a single-transmission tariff?

f) Stakeholders are requested to comment on the tariff strictures listed above for each business activities within the value chain.

g) Please comment on the fairness and justification of allocating capacity costs/charges to consumers based on their demand and provide an alternative.

h) How do we allocate the energy costs to customers based on a R/day per consumer?

i) How can transmission costs be allocated in a manner that is fair?

j) Should NERSA set the trading tariffs, explain why?

k) NERSA's view is to review tariffs every quarter. What is the period to review the licensees' tariffs? In addition, explain the rationale for the proposed time frame.

11.6.6.10. The generation tariff consists of single part tariffs which ensures that all costs (fixed and variable) are recovered through R/kWh. This option creates a volumetric problem whereby declining volumes lead to generators being unable to recoup their fixed costs. The second option is a two-part tariff, which recover variable costs through R/kWh and fixed costs through R/KVA. This option ensure that fixed costs are recovered even though volumes are declining.

11.6.6.11. Transmission costs will be recovered through a single tariff structure, which entails R/kWh/KM and R/KVA/KM for the Independent System

Operator and Market Operator, respectively, to recover their full cost of supply.

11.6.6.12. At the distribution, the tariff structure will encompass Dx for wires business and Dx for trading. For the distribution wires, the tariff will be a single-part tariff, which is R/KVA per KM, or R/kWh per KM to ensure that the Dx wires business recovers its costs of rendering the business.

11.6.6.13. Trading has the following tariff structure options:

11.6.6.13.1. A single-tariff structure, which is made-up of R/kWh relating to variable, fixed costs and customer servicing costs.

11.6.6.13.2. A two-part tariff structure is a tariff structure whereby the fixed costs and customer servicing costs are recovered through R/customer per month and variable costs, which are recovered through R/kWh.

11.6.6.13.3. In the three-part tariff, structure variable costs will be recovered in R/kWh, fixed costs will be recovered through R/KVA, and customer-servicing costs will be recovered through R/customer per month.

11.6.6.14. This implies that a tariff at the trading level will be a sum total of Gx tariffs, Tx tariff, Gx tariff wire, surcharges and subsidies where applicable. Surcharges are a function of municipalities and The National Treasury as per section 256 of the Constitution and Municipal Systems Act, (Act No. 32 of 2000).

Stakeholder question: 26

Stakeholders are asked to consider the aforementioned tariff options and respond to the following questions accordingly:

a) Transmission tariffs that reflect both the capacity and the distance are being considered. Do you agree with the transmission tariffs that reflect both aspects?

b) Are transmission zones an appropriate mechanism, considering that today energy is injected into the grid from across South Africa?

c) Distribution tariffs that reflect both the capacity and the distance are being considered. Do you agree with the transmission tariffs that reflect both aspects?

d) Should municipalities have exclusive right to trade in demarcated municipal boundaries?

11.6.6.15. According to ACER (2019), Costs Recovery is the core objective of setting Tariffs. In this regard, 'Efficiency' mainly relates to cost-reflectivity and the economic signals sent to the network users for optimal use of the network. Other principles, such as non-discrimination, transparency, non-distortion, simplicity, stability, predictability and sustainability, are usually also pursued. The transmission tariff structure should reflect the structure of transmission costs. According to the pursued principles, the most suitable tariff basis (capacity, energy and/or lump sum) and targeted user groups should be determined to compose the tariff structure.

11.6.6.16. Electric Power Transmission is the bulk movement of electrical energy from a generating site, such as a power plant, to an electrical substation. The interconnected lines, which facilitate this movement, are known as a transmission network. At this point, [21] the transmission cost, which includes costs of operating the system, market operation and Central Purchasing Agency (CPA). Therefore, the tariff Structure will be limited to a single Transmission Tariff, which covers all allowed costs of the TSO.

[21] $Transmission\ Cost = \frac{Total\ Costs\ Incurred}{MVA/Line\ Kilometres}$

11.6.6.17. Electric Power Distribution is the final stage in the electricity delivery activity. It entails carrying of electricity from the transmission system to individual consumers. Power is carried in distribution networks through wires on either poles or underground. The trading and costs associated with these activities should be reflected in the tariffs. Accordingly, Distribution Costs shall be segmented into the following:

11.6.7. Purchase costs

11.6.7.1. These are pass-through costs as charged by generators and the transmission network service provider(s) and if applicable, a distribution service provider. These costs consist of the following elements:

11.6.7.1.1. Energy

11.6.7.1.2. Transmission services

11.6.7.1.3. Distribution services

11.6.8. Distribution costs

11.6.8.1. Distribution charges are intended to recover the costs of network operation and maintenance, as well as past investments made in the distribution network. The following are costs allowed for distribution that are the basis for Consumer Tariffs Determination:

11.6.8.1.1. Cost on Capital Employees

11.6.8.1.2. Depreciation

11.6.8.1.3. Return on assets

11.6.8.1.4. Operations and Maintenance

11.6.8.1.5. Allowable Technical and Non-Technical Losses

11.6.8.1.6. Overhead costs

11.6.8.1.7. Shared costs

11.6.9. Trading costs

11.6.9.1. Allowed costs

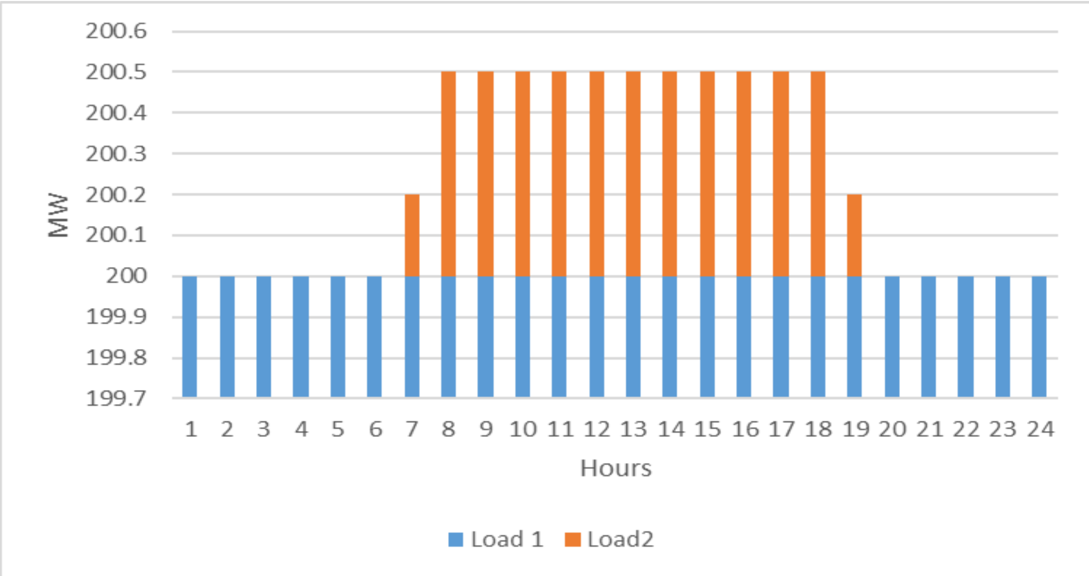
11.6.9.2. Trading margin

11.7. Annexure G: Load profiling in practise

11.7.1. Most consumers will have various aspects that characterise their load, from steady state load and in some cases virtually unpredictable variability, as outlined in the load profiles outlined below, where Load 1 would typically be referred to as baseload, Load 2 as mid-merit load and Load 3 as peak load). These are outlined in Section 7.1. The following examples use realistic information from research, however, they are indicative for purposes of comparing of different load profiles and the associated load build-up.

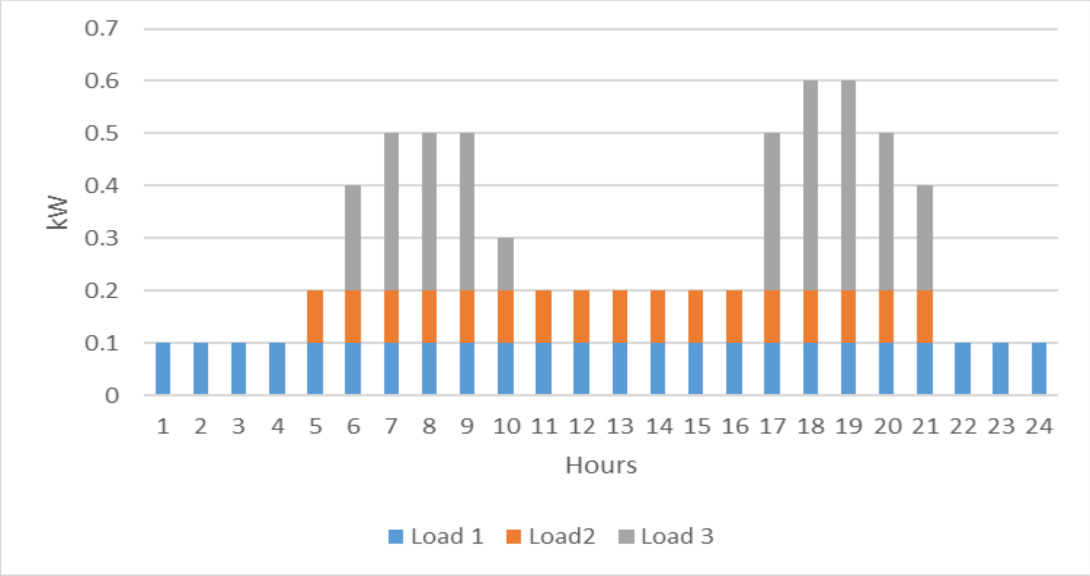
11.7.2. Figure 8 depicts the load profile of an indicative industrial consumer with 200 MW of steady state 24/7 load (e.g. production processes) and 0.5 MW of medium duration variable demand (e.g. 08:00 to 17:00 office hours).

Figure 8: Indicative Industrial consumer load profile



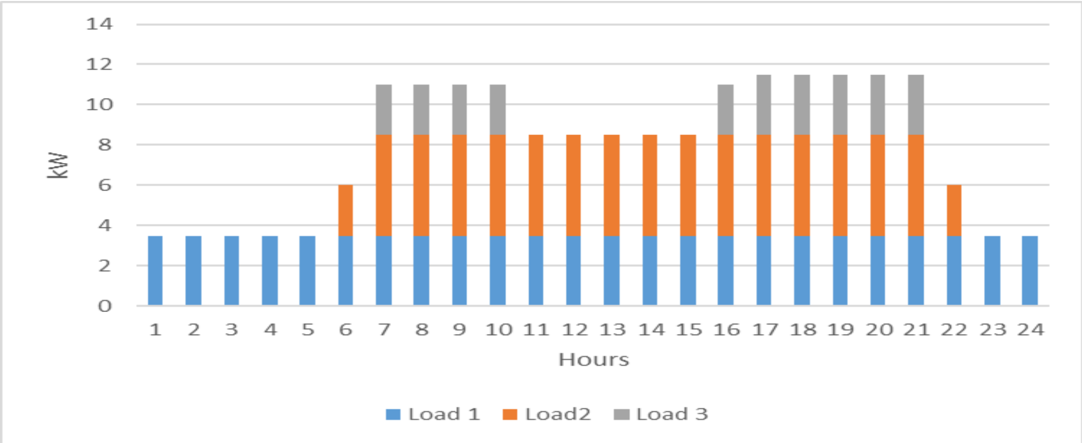
11.7.3. Figure 9 depicts the load profile of an indicative residential consumer with 0.1 kW of steady state 24/7 load (eg. refrigerator), 0.1 kW of medium duration variable demand (eg. air conditioner, pool pump and lighting etc.) and 0.4 kW of short duration variable load (morning and evening with food preparation, increased geyser heating and spatial heating).

Figure 9: Indicative residential consumer load profile



11.7.4. Figure 10 depicts the load profile of a hotel with 4 kW of steady state 24/7 load (eg. HVAC, refrigeration and lighting), 4 kW of medium duration variable demand (eg. day time hours, entertainment areas and lifts) and 2 kW of short duration variable load (morning and evening with food preparation, increased lifts).

Figure 10: Indicative Hotel consumer load profile



11.7.5. The purpose of these indicative load profiles is to illustrate how different types of consumers exhibit different types of load profiles over time and, at any point could include a combination of load types ranging from steady state to highly variable short-duration loads.

11.8. Annexure H: Targeted Time of Use Tariffs

11.8.1. The current energy prices are based on the time-of-use (TOU) approach, which seeks to send signals to customers to shift their consumption to certain periods of the day where the demand for electricity is low. The current ratio for peak to off-peak consumption is 1:8, which means it is eight times more expensive to consume electricity during winter peak periods as opposed to low season off-peak periods as depicted below – regardless of what the cost to serve might be, it does not cost more to generate electricity from the same plant in summer or winter.

11.8.2. Predictable steady state demand associated with Load 1 will be exposed to the same TOU rates as customers mainly using Load 3 during periods of peak demand and system constraints. Eskom has acknowledged that the TOU rates are not based on cost reflectivity but seeks to send signals to customers to shift their load – which could be justified from Eskom's perspective to reduce system constraints but would be considered irrational if the load cannot be sensibly shifted.

11.8.3. This affects households as much as industrial customers where 24/7 constant demand is priced higher during peak periods, but the load cannot be shifted. For examplee one cannot simply switch off a freezer during peak hours to reduce costs in the same way a smelter of chrome-ore cannot be switched off during peak hours to avoid peak charges, especially where equipment is designed to run in a steady state and unnecessary and frequent disruptions can cause damage.

11.8.4. The sophisticated use of Time of Use prices as a hybrid to address possible anomalies is being considered. For example the issue of positive behavioural change when a Load 3 consumer moves their load from a typical Load 3 period to a period when the market is balance at Load 2 (midday) or even Load 1 (midnight) – refer to paragraph 8.4.12.4 above.