



**Eskom Holdings SOC Ltd
Response to**

*NERSA'S CONSULTATION PAPER TO DETERMINE A NEW
PRICE DETERMINATION METHODOLOGY*

Published 24 September 2021

**Submission to NERSA
22 October 2021**

CONTENTS

EXECUTIVE SUMMARY	3
1. INTRODUCTION AND OVERVIEW	8
1.1 The Extended Framework.....	12
1.2 The Case for Incremental Change	14
1.3 Consultation and Project Timeline	17
2. OVERVIEW OF THE MYPD FRAMEWORK AND NERSA'S PROPOSED REVISIONS	20
2.1 Allowed Revenue and Cost of Service	20
2.2 Mapping Total Allowed Revenue to End Use Tariffs.....	25
2.3 Migration to Activity Based Costing.....	27
2.4 The Case for Overhauling the MYPD Methodology.....	28
2.5 The tariff design process.....	38
3. RESPONSE TO QUESTIONS ASKED OF STAKEHOLDERS	43
3.1 Industry Transformation	43
3.2 Activity Based Costing	44
3.3 Demand Analysis	47
3.4 Generation Costs	49
3.5 Transmission, System & Market Operation Costs	56
3.6 Distribution Equipment Costs.....	63
3.7 Trading Costs	68
3.8 Retailing Costs	69
3.9 Type of Service Costing – Differentiated Load Profiles	70
3.10 Time of Use Pricing.....	70
3.11 Indexing for Year-On-Year Price/Tariff Increases.....	72
4. PROPOSED WAY FORWARD.....	74

EXECUTIVE SUMMARY

i. First step towards the development of new price determination methodology

Eskom hereby provides initial comments on the National Energy Regulator of South Africa (NERSA) Consultation Paper to Determine a New Price Determination Methodology. It is confirmed that this consultation is the first step towards the process to develop a new price determination methodology. It is not a proposed methodology. It is rather interpreted as a request to determine whether certain data requests are possible, provide some idea on outcomes wished to be achieved and includes a mixture of policy and operational matters. There seems to be a significant change from the prevailing revenue, cost, price and tariff determination processes that have been approved by NERSA. Understanding the consultation paper in the context of the objectives, purpose and applicability of legislative and regulatory framework of the country is challenging. Eskom is committed to participating in any review process within the required regulatory framework.

ii. Restructuring of the industry is being led by the DMRE

It will not be possible to address any industry restructuring matters as part of this consultation process. The relevant policy Government Department, the Department of Mineral Resources and Energy (DMRE) has indicated that a process is underway to address industry changes. Any changes to tariff related matters, such as on market related matters will only follow any policy decisions that will be made when considering the changes in the industry.

iii. Any methodology must be aligned to the policy, legislative and regulatory framework

NERSA is guided by the relevant policy, legislation, regulatory rules, codes and guidelines. The NERSA regulatory framework currently includes licences, codes, methodologies and rules. These have all been approved by NERSA Board and have followed the appropriate consultation and governance processes. It would thus be necessary to ensure alignment with all existing NERSA legal instruments before the outcome of this consultation paper is employed for the development of a draft methodology for further consultation. In addition, it would be incumbent on NERSA to ensure alignment with the hierarchy of the legal framework to avoid confusion and possibly resulting in negative impacts on the industry.

iv. Incremental changes rather than big bang changes are viable

What can be inferred from the consultation paper, and if the actual methodology follows in a similar manner, is that a big bang change could be expected. The key focus seems to be an apparent correction (albeit based on incorrect and misinformed assumptions) of industrial tariffs. It is evident that other customer groupings are not sufficiently considered. A case in point being the residential sector. The apparent objective seems to be that all customers need to objectively be charged tariffs that are allocated to them. Indications are that cross subsidies will be done away with. This will undoubtedly contribute to some adverse experiences, the consequences of which have not been clearly articulated. The regulatory environment is complex and thus a phased approach is best suited so as to ensure an optimal outcome. It is essential to determine the economic impact on various customer groupings.

It is unfortunate that relatively limited reference to the current MYPD Methodology is made. Rather than mapping specific elements of the MYPD Methodology to observed performance and specific objectives and principles sourced from legislation and policy, NERSA has simply asserted that the entire pricing approach is flawed and needs to be replaced. Quite simply, the problem that NERSA wishes to address is not clearly articulated and the case has not yet been made to replace the MYPD Methodology in its entirety. It is Eskom's contention, and is common knowledge that failure by NERSA to implement the current methodology in full and consistently has contributed to many of the challenges facing Eskom.

v. Meaningful consultation processes are essential

Even for an incremental change to the pricing methodology one would expect a comprehensive plan for stakeholder consultation at various stages of the review.

vi. The determination of a revenue requirement is essential

It has been clearly clarified that a need exists for the determination of a revenue requirement. This concept can also be referred to as establishing the efficient costs and a fair return. It has also been established that the sales forecast, as determined by NERSA, will also need to be considered. This is a common approach used by many regulators across the world. Without knowing an expected revenue flows makes it impossible to forecast financials and cash flows

which are the cornerstone for engagements with key stakeholders including the management, the board, auditors, lenders, rating agencies, labour and government.

vii. Transitional Mechanisms are essential

It is essential to ensure that an appropriate transitional mechanism is included if any radical changes in the determination of the appropriate pricing mechanism for electricity is implemented after stakeholders have responded to this consultation paper. The NERSA has made decisions through the current MYPD and RCA process that impacts the recovery of efficient costs in future financial years. In addition, the South African court decisions would need to be addressed. These would be binding on NERSA to allow for recovery in subsequent financial years.

viii. Separation of costs from tariffs

There is a clear indication of the separation of costs from tariffs. It has been illustrated that these are two very different concepts and cannot be merged and used as proxies. This again is a world-wide phenomenon and has been utilised by regulators of the electricity industry. In addition, all efficient costs would need to be considered. Assumptions cannot be made on particular generating technologies supplying particular customers.

ix. Application of required sequential processes

It is submitted that many of the ideas and concepts that this consultation wishes to implement are wrongly placed. This results in impossible requirements for the whole industry. It is proposed that the existing framework, appropriately applied could provide the envisaged outcomes. Eskom has provided clear guidance on the existing processes that can easily be utilised to allow for further progress. The sequential process which is already applied is:-

- First, the determination of the efficient costs and a fair return
- Second, determination of the cost to serve
- Thirdly, tariff design

It needs to be cautioned that each of these three steps are complex and require various considerations, especially in accordance with already existing policy, legislation and regulatory rules and codes.

x. Migrating towards cost reflectivity should be considered

Recognition needs to be given to Eskom's revenue not being at a level where efficient costs and a fair return are recovered. This obviously implies that whatever the methodology is, if what is being referred to as objective costs, are recovered they will be significantly higher than presently. This will also contribute to the adverse effects of a big bang approach. The continual migration towards cost reflectivity will allow this level of flexibility.

xi. Timeous Decision-making is challenging, not methodologies

Eskom humbly submits that further significant progress can easily be made if timeous decisions within the current methodologies are made after due process is followed. NERSA already has powerful frameworks in place that could be applied to address many relevant and viable concepts that are alluded to in the consultation paper. It again needs to be cautioned that all decisions have impacts that need to be considered. A big bang approach is not supported. An incremental approach is proposed. This also implies that timeous decision making is required. It goes without saying that due processes need to be followed.

xii. Eskom has reviewed NERSA's rejection decision of MYPD 5 application

A court process has been initiated to allow for NERSA to make a revenue decision effective from 1 April 2022 using the prevailing methodology.

xiii. Eskom has submitted a proposal for restructuring of Eskom retail tariffs

In an incremental fashion, Eskom has made proposals for certain elements of Eskom's retail tariffs to be restructured. This submission was made during August 2020. NERSA has already consulted with stakeholders on Eskom's application. It is now for NERSA to make a decision on this application. This will allow for the journey toward cost reflectivity, at a tariff level, to be continued.

xiv. Continuation of journey towards cost reflectivity within legal framework will benefit all

It is proposed that NERSA continue with the journey towards cost reflectivity at a revenue and a tariff level. An incremental approach be adopted. The existing frameworks provide sufficient opportunity for the realisation of many objectives espoused in this consultation paper to be achieved. Further analysis on the existing methodologies and frameworks will need to be critically evaluated to determine if identified objectives can still be met. The impact of changes on consumers would need to be carefully considered. In addition, direction should be taken from the policy changes regarding any industry restructuring.

xv. Eskom submits that three principles are not appropriate for regulating the electricity industry

It is submitted that the three principles that this consultation is based on namely activity based costing; type of use tariffs and marginal pricing – are not appropriate to meet the NERSA mandate of ensuring that licensees recover efficient costs and a fair return. These are not regulatory approaches at all.

1. INTRODUCTION AND OVERVIEW

Eskom hereby provides initial comments on the National Energy Regulator of South Africa (NERSA) *Consultation Paper to Determine a New Price Determination Methodology* (hereafter referred to as the "Consultation Paper"). It is confirmed that this consultation is the first step towards the process to develop a new price determination methodology. It is not a proposed methodology. It is rather interpreted as a request to determine whether certain data requests are possible, provide some idea on outcomes wished to be achieved and includes a mixture of policy and operational matters.

It is also noted that this consultation paper seems to be a significant change from the prevailing revenue, cost, price and tariff determination processes that have been approved by NERSA. It is therefore pertinent to understand the very limited timeframes for the consultation process. It is appreciated that stakeholder consultation workshops have subsequently been arranged. However, the engagements held at the workshop has heightened the level of challenges faced in understanding the consultation paper in the context of the objectives, purpose and applicability of legislative and regulatory framework of the country.

Eskom has been challenged by the confusing nature of this consultation paper. It seems to address a mixture of playing fields including a market, which does not exist. It will not be possible to address any industry restructuring matters as part of this consultation process. The relevant policy Government Department, the Department of Mineral Resources and Energy (DMRE) has indicated that a process is underway to address industry changes. Any tariff related matters, e.g. on market related matters can only follow from any policy decisions that will be made when considering any changes in the industry.

All entities, including utilities can only respond to requests made within the legislative framework. There can only be a single legislative framework at a time. The prevailing legislative framework will need to be respected. Any prospective changes cannot be assumed when consulting on a process to determine a pricing methodology. It is important to ensure alignment with the legislative and regulatory framework to avoid any confusion and mixed messages and actions.

Eskom is well aware of the challenges inherent to the design and administration of a price determination methodology and the many complex factors needing to be assessed in the

determination of allowed revenue and tariffs. Even a short-list of factors to be determined is daunting – requiring an assessment of the level of prudently incurred costs; the ideal level of maintenance to be carried out; the allocation of financial risk; the quality and reliability of service best suited to the wide range of customer preferences; and how all of these factors are to be treated in an uncertain and sometime volatile commercial environment.

Likewise, the importance of the price setting methodology cannot be overstated. Within the context of the Multi-Year Price Determination (MYPD) Methodology the many complex rules of which it is comprised and the manner in which it is administered, ultimately affects the quality and level of services Eskom is able to provide to its customers and Eskom's long term financial sustainability – both of which have a measurable impact on South Africa's economic performance and the well-being of its citizens. With this in mind, Eskom supports the ongoing improvement of the regulatory methodology under which regulated revenues and tariffs are set. Eskom has acknowledged that learnings and experiences from the application of the methodologies need to contribute to their review. It is in this vein that Eskom submitted proposals on the review of the MYPD methodology, for NERSA consideration, during May 2020.

That said, Eskom is concerned that the assessment of NERSA's Strategic Plan is considered to have provided the basis of a "thorough stakeholder consultation process" highlighting the "failings of the current MYPD Methodology" and providing "evidence and guidance on the need to overhaul it" (S.1.5).

Moreover, in highlighting stakeholders' concerns that "certain sections of the Methodology did not adequately address some of the intended objectives, namely to provide price stability" and then going well beyond this in asserting that a "thorough assessment suggests that it is the entire pricing approach that is flawed and needs to be replaced" (S.4.1) indicates that the matter may have been determined prior to the start of the formal process of consultation.

The lack of meaningful consultation is more concerning given the underlying premise on which such findings seem to have been based. For example, it is disingenuous for NERSA to imply that the intended objective of the MYPD Methodology is to provide "price stability" (S.4.1). The objectives of the MYPD Methodology as set out in the Energy Regulator's Reason for Decision (presented below for ease of reference) are far more nuanced than implied in the Consultation Paper.

“The following are the objectives of the MYPD Methodology

- a) to ensure Eskom's sustainability as a business and limit the risk of excess or inadequate returns while providing incentives for new investment;*
- b) to ensure reasonable tariff stability and smoothed changes over time consistent with socio-economic objectives of the Government;*
- c) to appropriately allocate commercial risk between Eskom and its customers;*
- d) to provide efficiency incentives without leading to unintended consequences of regulation on performance;*
- e) to provide a systematic basis for revenue/tariff setting; and*
- f) to ensure consistency between price control periods.”*

Defining 'stable prices' "as a function of predictability, affordability, and competitiveness" as found in the Consultation Paper only adds to our concerns. It is doubtful that this definition could be viewed as falling from common usage, nor is it found in the economic literature. This gives cause to question whether it has been created specifically to support a predetermined outcome.

The importance of this matter is elevated by statements attributed to business associations arguing that the current revenue-based approach "has not delivered the intended predictability of the MYPD over the long term" (S.4.1). This theme is mirrored in a statement attributed to the Energy Intensive Users Group (EIUG) in which the following factors were cited as creating uncertainty in the price path:¹

- the timing of the liquidation of the 2018/19 RCA ruling;*
- the outcome of Eskom's legal review of Nersa's treatment, in the MYPD4 allowable-revenue determination, of government's R69-billion injection into the utility;*
- the tariff impact of the High Court's decision to refer Nersa's MYPD3 determination for years two to four back to the regulator, owing to a deviation from the MYPD methodology;*

¹ <https://www.polity.org.za/article/large-power-consumers-call-for-overhaul-of-tariff-setting-methodology-2020-06-11>

- *the upcoming RCA applications for MYPD4 years one and two, which Eskom is likely to submit soon; and*
- *Eskom's strategic objective to increase tariffs as part of efforts to improve its financial position.(attributed to EIUG, Polity)*

In reference to the RCA in the first point above - had NERSA based its initial revenue decisions on reasonable forecasts of allowed costs and sales there would have been no need for Eskom to apply to the courts for relief. Similarly, had NERSA not deviated from the MYPD Methodology in an illogical and unreasonable manner, the uncertainty falling from the High Court's order for NERSA to reconsider its revenue decision would not have occurred.

With such examples in mind, the lack of predictability and stability of the price path is more accurately attributed to the **administration** of the MYPD Methodology – rather than the Methodology itself.

A final passage from the article cited above highlights perhaps the most critical aspect of the review at hand:

“The high degree of price uncertainty makes capital and operational planning very difficult and deters investment in South Africa, thus hurting the economy. We urge Nersa to implement inflation-linked tariff increases for the next five years in order to provide pricing certainty and allow Eskom and industry to plan within these parameters.” (Attributed to EIUG, Polity)

Equally, having to operate in an environment in which prices do not cover the cost of supply makes Eskom's capital and operating planning difficult as well - deterring efficient investment and hurting the economy. If tariff increases are linked to inflation for the next five years as suggested by the industry group (rather than Eskom's prudent cost of supply) both Eskom and industry may have to plan on a future marked by sub-optimal maintenance of electricity infrastructure and reduced levels of system reliability that this entails, and continually have to rely on Government support through the tax payer.

1.1 The Extended Framework

1.1.1 NERSA Mandate vs Government Mandate

It is the role of government to determine policy including the structure of the Electricity Supply Industry. This is done through the Electricity Regulation Act (ERA). NERSA, in the consultation paper, makes certain presumptions about the industry structure. It is understood that this is not within NERSA's mandate. NERSA is required to act within the legislative framework of the governing legislation. The presumptions are not aligned to the current Electricity Regulation Act (ERA). It is known that the DMRE will imminently be publishing an amendment of the ERA as well as reviewing the Electricity Pricing Policy (EPP). It would thus be correct for NERSA and all other stakeholders to ensure that order is followed in ensuring that the mandated policy Government Department undertakes its own legislative processes to address any legislative changes.

A more robust understanding of the objectives and principles which are to guide the development of the pricing methodology falls from what can be thought of as a regulatory scheme of governance established by way of legislation – guided by Government Policy and implemented by way of various rules, codes of practice and guidelines. This integrated scheme of governance (ideally) provides the foundations of a predictable and stable regulatory environment predicated on the structural integrity, the system as a whole and the administration of the individual elements of which it is comprised.

In a similar vein, NERSA (section 3.6) refers to an “extended framework” in the determination of regulated revenue and tariffs based on the Tariff Principles presented in section 15(1) of the Electricity Regulation Act as shown below.

“(1) A license condition determined under section 14 relating to setting or approval of prices, charges and tariffs and the regulation of revenues -

(a) must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return;

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

(c) must give end users proper information regarding the costs that their consumption imposes on the licensee's business;

(d) must avoid undue discrimination between customer categories; and

(e) may permit the cross-subsidy of tariffs to certain classes of customers.”

1.1.2 Consultation paper seen to be non-compliant with NERSA's governing legislation (ERA)

Section 7 of the ERA provides the activities that require licensing. System Operator and Market operations are not separate licensable activities under the current legislation. Sect 14(2) of the ERA refers to the methodology to be used for the determination of rates and tariffs which must be imposed by licensees.

Sect 15(1)(a) provides that a licence condition determined under Sect 14 relating to the setting or approval of prices, charges and tariffs and the regulation of revenues must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return. Clarity is sought from NERSA on how it will regulate a non-licensed entity and how a price is determined for non-licensed entities.

Provisions of the Electricity Pricing Policy (EPP) are further cited in the Consultation Paper speaking to cost recovery and the revenue requirement. Importantly, Policy Position 1 of the EPP provides that:

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

This is further supported in section 2.2 of the EPP in which:

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

Compared to these clearly articulated principles found in legislation and government policy, we find the mooted principles that define NERSA's proposed methodology for price determination as arbitrary, and either redundant to existing provisions of legislation, codes and guidelines, or incompatible with those provisions.

1.2 The Case for Incremental Change

The technical complexity underlying the regulatory pricing regime and the codes, guidelines, and rules of which it is comprised favours incremental change over the complete overhaul called for in the Consultation Paper. To see why this is the case consider that the determination of allowed revenue and tariffs takes place within an extended framework comprised of Guidelines, Codes and Rules, which given the extent of NERSA's proposed revisions to the pricing methodology would in turn likely require revision as well, which are not addressed at all in the Consultation Paper. Elements of the extended framework that have a high likelihood of needing revision to align to a new pricing methodology include:

- Cost of Supply Framework for Licensed Electricity Distributors in South Africa
- South African Grid Code and the South African Distribution Code
- Minimum Information Requirements for Tariff Applications (MIRTA)
- Regulatory Reporting Manual (RRM)
- Prudency Guidelines
- Small-Scale Embedded Generation (SSEG) tariffs
- Eskom Retail Tariff and Structural Adjustment Methodology (ERTSA)
- The Distribution Tariff code

All licensees are bound by the requirements of the Codes and these would have to be revised first before any NERSA approved methodology is published and should not be in a cost determination methodology.

The Distribution Codes states the following:

- 4.1.1 Tariffs should recover current regulated revenue requirement but may reflect future cost drivers in their structure to provide clear pricing signals to the customer, that promote economic efficiency.*
- 4.1.5 Cost pooling (aggregation and averaging of costs) is required due to practical reasons.*
- 4.2.1.4 Tariff charges (including energy costs) will not be based on customer specific assets or services, but aggregated and averaged based on justifiable pooled costs.*
- 4.2.1.5 The components that make up a tariff structure will be aggregated and averaged to a lesser or greater degree depending on the tariff category being served.*
- 7.1 Tariff structures should reflect cost drivers as far as possible. Where tariffs structures do not reflect costs, there is risk associated with mismatching of costs, tariff conversions and changes in volume forecast. The distributor/service provider shall be allowed to mitigate this risk, through appropriate tariff or claw-back mechanisms (for both under or over recovery of revenue) within the revenue requirement.*
- 7.2 The tariff charges (rates) shall be calculated based on the approved revenue requirement, volume forecast for demand and energy and customer numbers. At the end of each revenue review period, the NERSA may audit and verify the tariff charges (rates) calculations and results.*

This Consultation Paper is in contradiction with the existing Distribution Tariff Code. These include concepts introduced in this Consultation Paper that have never been encountered previously, anywhere in the world, such as type of use tariffs.

The NERSA regulatory framework currently includes licences, codes, methodologies and rules. These have all been approved by NERSA Board and have followed the appropriate consultation and governance processes. Thus it would be necessary to ensure alignment with all existing NERSA legal instruments before the outcome of this consultation paper is employed for the development of a draft methodology for further consultation. In addition, it would be incumbent on NERSA to ensure alignment with the hierarchy of the legal framework to avoid confusion and possibly resulting in negative impacts on the industry.

The extended framework also needs to address legislation that speaks to the administration of the pricing decision (i.e. in addition to the ERA and NERA) inclusive of:

- The Municipal Finance Management Act
- Public Finance Management Act
- Local Government (Municipal Systems) Act (2000) ("Systems Act")
- Municipal Fiscal Powers and Functions Act (2007) ("MFPFA")

It is quite conceivable that certain provisions of legislation may limit the scope of mooted revisions to the pricing methodology unless amended. This aspect of the review by itself will require significant attention in implementation.

1.2.1 Conflict with other legislative mandates

The South African Bureau of Standards (SABS) is mandated by the Standards Act to issue Standards for the country. It is the only body that may issue standards for the country and all entities in South Africa are required to adhere to those standards. SABS has issued a metering standard. The data required in the Consultation Paper is likely not provided for in the metering standard therefore there is no obligation on service providers to collect the information. It is thus incumbent upon NERSA to ensure alignment with such existing legal requirements. This is the only way to ensure order in the development of any new methodology that it is envisaged that this Consultation Paper will result in, once the responses have been received from stakeholders.

1.2.2 Building from current methodologies

Perhaps the most troubling aspect of the review process to date is the relatively limited reference to the current MYPD Methodology and no new/alternate methodology is actually being proposed. Rather than mapping specific elements of the MYPD Methodology to observed performance and specific objectives and principles sourced from legislation and policy – NERSA has simply asserted, as in Section 4.1, that a "thorough assessment" suggests that the entire pricing approach is flawed and needs to be replaced. Quite simply – the case has not yet been made to replace the MYPD Methodology in its entirety. At a very broad level of thinking, a more practical approach would be to:

- identify those elements of the current methodology warranting review;
- develop and design alternatives;
- identify the administrative processes needing to be carried out to effect change;
- undertake cost benefit analysis (qualitative or quantitative) of the options available; and
- develop and implement project plan.

Even for an incremental change to the pricing methodology one would expect a comprehensive plan for stakeholder consultation at various stages of the review. This would include:

- Publication of an issues paper, with a proper alternate methodology motivating the reasons for change and matters to be addressed;
- Stakeholder workshops held covering technical matters;
- Written comments called for at each major stage of the review;
- Publish for comment draft revisions to the pricing methodology
- Incorporate comments in revised draft and publish for final round of consultation;
- Public hearing on final draft determination.
- Decision and Reason for Decision, and publication of pricing methodology

1.3 Consultation and Project Timeline

The project timeline presented in the Consultation Paper (S. 12) covering some 37 days is far too limited given the scope of the review and the significance of its outcome. It is understood that this is only the first step towards the development of a new pricing methodology. It is evident that significant amount of development work and alignment with existing policy, legislation, regulatory rules, licence conditions, codes and guidelines needs to be undertaken prior to the finalisation of a new methodology. Local and global benchmarks indicate that significant regulatory reviews of this magnitude require months of analysis and consultation leading up to a draft determination, which is then typically put through a final round of stakeholder consultation prior to publication of a final determination.

To put this into perspective one can compare the extremely short timeframe in which the current review of pricing methodology is to be carried out in less than two months to previous reviews of the MYPD Methodology ranging from seven to twenty months, and related guidelines to augment the price determination process (i.e. Prudency Assessment and RRM) of seventeen to twenty months.

Table 1: Consultation Timelines – Selected Regulatory Determinations

NERSA - Review of MYPD Methodology (2011-2012)	NERSA Review of MYPD Methodology (2016)	Guidelines for Prudency Assessment (2017-2018)	Development of Regulatory Reporting Manuals (2007-2008)
Consultation Paper published 14 October, 2011	Consultation Paper published 15 April 2016 for comment.	Discussion Document published for comment 18 th December 2017	Review of global best practice 24 th April through 30 th May 2007.
Second consultation paper published 4th Sept. 2012	Public hearing 2 June 2016	Extension for comments to 31 st Jan. 2018	Workshops with key stakeholders July - November 2007.
Public hearing held 1st November 2012	Draft decision published 8 September 2016	Public hearing held on 1st March 2018.	Draft RRM published 19 th October 2007.
	2 nd public hearing 30 th September 2016		Stakeholder workshop 23 rd November 2007
Approved 29 th November 2012 Published November 2012	Approved 30 th October 2016 Published November 2016	Approved 29 th August 2018. Published August 2018.	Approved 31 st July 2008 Effective 1 Sept. 2008.
Elapsed time * <u>14 months</u>	Elapsed time* <u>7 months</u>	Elapsed time* <u>20 months</u>	Elapsed time* <u>17 months</u>

* Consultation Paper to Final Determination.

Moreover, the scope of this review appears to extend to matters of policy which – while of significant importance to the industry do not fall under NERSA's mandate to change. With this in mind, we propose that NERSA considers revising the scope of the review so as to allow for two complimentary processes of consultation, viz:

- a) Review of the MYPD Methodology and related regulatory instruments within the narrow bounds to which NERSA has decision making powers.

- b) Once the DMRE has provided direction on policy matters, a process focusing on the closely related issues of future market and industry structures and the regulatory frameworks that need to adjust to this changing environment, could be considered.

2. OVERVIEW OF THE MYPD FRAMEWORK AND NERSA'S PROPOSED REVISIONS

Before directly addressing Eskom's issues on the proposals contained in the Consultation Paper it may help to form a common understanding of the prevailing MYPD Methodology and the extended framework in which it sits.

2.1 Allowed Revenue and Cost of Service

From the title of NERSA's document it already appears that what is being consulted on is not about a revision to the revenue methodology but rather a revision to the pricing methodology thus in reality more about changes to the ERTSA than to the MYPD Methodology.

It has been clearly clarified that a need exists for the determination of a revenue requirement. This concept can also be referred to as establishing the efficient costs and a fair return. It has also been established that the sales forecast, as determined by NERSA, will also need to be considered. This is a common approach used by many regulators across the world. Without knowing an expected revenue flows makes it impossible to forecast financials and cash flows which are the cornerstone for engagements with key stakeholders including the management, the board, auditors, lenders, rating agencies, labour and government.

The NERSA consultation paper (to borrow from professor Anton Eberhard's presentation at the NERSA workshop of 18 October 2021) seems to have diagnosed one of the problems as being the regulatory determination of revenue, which (NERSA assumes) then results in loss of sales volume, which (NERSA assumes) then results in clearing account adjustments to recover lost sales), thus 'chasing your tail' as NERSA puts it. This is however not correct.

Firstly, regarding the assumed loss of sales volumes, NERSA seems to assume that it is / was mainly a function of increasing prices. A number of studies by credible independent specialist economists have however shown that the main or dominant drivers of electricity sales volume reduction has **NOT** been Eskom's electricity price but instead has been a function of lack of GDP growth, divestment and de-industrialisation in SA over the last decade, commodity cycles, policy uncertainty etc. Indeed, when Eskom's prices were increasing at 25% per year (thus, around 19% above inflation) prior to FY 2012/13 the annual electricity demand was still growing at 2.7% (FY 2010/11) and 0.2% (FY 2011/12). However in the subsequent years of MYPD3 when Eskom's tariffs were increasing at around 8% per year (thus, around 2% above

inflation) the sales volumes were decreasing at between 0.2% and 0.9% per year. Indeed, for FY 2017/18 when NERSA allowed a nominal price increase of below 2% (thus, a real price decrease of around 4%) the sales volumes decreased by 0.9%, and for FY 2018/19 when NERSA allowed a nominal price increase of below 6% (in line with inflation thus a nil real increase) the sales volumes decreased by 1.8%.

This of course does not address the situation of municipal prices, which are much higher than Eskom's based on NERSA's annual municipal tariff adjustment process. If there has been any effect of price elasticity of demand it is likely to have been in response to the much higher municipal prices, which however has been set by NERSA.

Secondly, the clearing account adjustments which then followed was not to 'recover lost sales'. Indeed, if such lower volumes had been correctly forecasted or anticipated by Eskom and NERSA there would have been no clearing account adjustments. The adjustments emanated purely because the sales volumes forecasts (as made in 2012 for the five-year MYPD3 cycle) did not correctly anticipate the volume outcome. As such recovery of the fixed cost was based on a higher sales volume thus resulting in a lower rate per kWh for fixed cost. Therefore the clearing account adjustments were NOT to 'recover lost sales' but purely to recover the under-recovered fixed cost. During every clearing account process Eskom has submitted various papers to explain this. It was also the subject of most of Eskom's applications to the High Court for a judicial review of a NERSA RCA decision, and the High Court confirmed this and found in Eskom's favour on that matter.

Therefore it seems the entire diagnosis and departure point of NERSA concern with setting of revenue is misplaced and without foundation.

Furthermore, the basis of the world-wide approach in sound economic regulatory approach of setting revenue according to the 'cost of service' model is not a 'unique solution' adopted for some reason by regulators – the approach is founded on basic fundamental corporate finance principles. In fact there can be no other approach in order to achieve long term financial sustainability which is a key and critical basis for attracting the needed capital (debt and equity) in the first place so as to enable the investment in the expensive assets which is characteristic of this asset-intensive electricity industry.

Therefore, the cost elements or cost 'building blocks' must be recovered through revenue in order to be financially sustainable in the long term and to attract the capital in the first place to enable the product to be provided. Thus, the role of revenue is to recover those legitimate and inherent cost elements. There can be no means of assurance that the cost elements are recovered other than that the revenue must be equal to the sum of the main cost elements of fuel cost (primary energy), operating and maintenance cost, depreciation and cost of capital. If 'revenue' as a concept does not feature in the regulatory methodology there can be no means of measuring or assuring that the cost elements are recovered.

There is sometimes the idea that the various other common economic regulation approaches such as 'price cap' is not based on revenue. This is however not correct – even for a 'price cap' approach the initial reference price must and is set with regard to the same four conventional main cost elements or 'building blocks' of fuel cost (primary energy), operating and maintenance cost, depreciation and cost of capital.

Setting of revenue is not the main driver of Eskom's sales volumes and does not result in 'chasing your tail'. Nor does retrospective clearing account adjustments for changes in sales volume constitute 'recovering of lost sales' – it is merely a mechanism to recover under-recovered fixed cost, which is one of the four 'cost building blocks' and is required to be recovered for long term financial sustainability and thus critical to enable capital to be attracted to the entire electricity industry.

As described in Section 1 of the MYPD Methodology,² it:

*“was developed for the regulation of Eskom's required revenues. It forms the basis on which the National Energy Regulator (NERSA) will evaluate the price adjustment applications received from Eskom. ,,,,,, “ **It is a cost-of-service-based methodology with incentives for cost savings and efficient and prudent procurement and overall operations by the licensee (Eskom).**” (Emphasis added)*

² NERSA, Multi-Year Price Determination (MYPD) Methodology 2016.

As a cost-of-service approach to setting Eskom’s allowed revenue the MYPD Methodology has as its central focus the revenue required to recover the prudent and efficient cost of supply. This revenue requirement is formalised in the MYPD Methodology in terms the ‘Allowable Revenue Formula’ which is illustrated below in a highly abridged format.

Table 2: Build-up of Allowed Revenue

Total cost of service	Return on Assets	<p>Under provisions of the MYPD Methodology:</p> <ul style="list-style-type: none"> ➤ Allowed Revenue is built up from forward looking estimates of qualifying costs as described in the MYPD Methodology; and is ➤ Assessed for prudence following NERSA’s Guidelines for Prudence Assessment. ➤ Revenue and cost adjustment mechanisms reconcile variances in forecast to actual values of inputs to the revenue requirement on an <i>ex-post</i> basis.
	Depreciation	
	Operating expenses	
	Primary Energy	
	IPPs	
	International Trade	
	IDM	
	Research & Development	
	Service Quality Incentives	
	Levies and Taxes	

Average unit price is then calculated such that at deemed forecast sales volumes the revenue allowance is just obtained in expectation. Importantly – this average unit cost is primarily employed in calculating the percentage adjustment to individual elements of a given tariff class, it is not used as intimated in the Consultation Paper to derive tariffs. The structure of tariffs is determined under a separate process divorced from revenue determination – which might be carried out at different or roughly parallel timelines (refer to Eskom 2020 retail tariff plan submitted to NERSA which sets out how the tariffs would be derived). The importance of this administrative feature of the pricing approach is discussed below.

2.1.1 Transitional Mechanisms are essential

It is essential to ensure that an appropriate transitional mechanism is included if any radical changes in the determination of the appropriate pricing mechanism for electricity is implemented after stakeholders have responded to this consultation paper. NERSA has made decisions through the current MYPD and RCA process that impacts the recovery of efficient costs in future financial years as far as Eskom is concerned. These are the RCA

implementation (liquidation) decisions already made. In addition, it is envisaged that further RCA balance and implementation decisions will still be made for subsequent years. These balances could be in favour of the consumer or in favour of the Eskom. It is essential that appropriate transitional mechanisms are put in place to ensure continuity.

In addition, the South African court decisions already made, review applications already made and appeal applications already made need to be accommodated in any transitional mechanism. These court decisions cannot be ignored. It is likely that the courts would direct NERSA to make further decisions for previous financial years. These would be binding on NERSA to allow for recovery in subsequent financial years.

2.1.2 Applicability of scope of consultation paper includes all utilities

The three versions of the MYPD methodologies approved by NERSA since 2006, have traditionally applied only to Eskom. This consultation paper infers that the applicability of the new pricing methodology will be applicable to all utilities. It is understood that significant development of processes, systems and infrastructure would be required for implementation, once the responses from this consultation paper is used for the basis of the development of a new pricing methodology. It is understood that many municipalities are still in the development process of responding to the existing requirements for the price determination of electricity and have come a far way in supporting NERSA's requirements for cost of supply studies. A change in the methodology related to cost-recovery and tariffs would effectively take municipal licensees back in the process to the detriment of the industry. It can be assumed that significant time would be needed to allow for the testing and implementation across all utilities. NERSA's mandate in ensuring a non-discriminatory approach is paramount. It is envisaged that it would take several years after the development of a methodology to actually implement such a methodology. It is thus appropriate that incremental changes be considered.

2.1.3 Big bang changes have been proposed

For the purpose of understanding the apparent objectives of this consultation paper, the impossible; the inappropriate and the violation of policy, legislation, regulatory rules and codes are excused. Thus, what can be inferred is that if the actual methodology follows in a similar manner, a big bang change could be expected. The key focus seems to be an apparent correction (albeit based on incorrect and misinformed assumptions) of industrial tariffs. It is

evident that other customer groupings are not sufficiently considered. A case in point being the residential sector. The apparent objective seems to be that all customers need to objectively be charged tariffs that are allocated to them. Indications are that cross subsidies will be done away with. This will undoubtedly contribute to some experiences of a big bang change.

2.1.4 Migrating towards cost reflectivity is not considered

Recognition is not given to Eskom's revenue not being at a level where efficient costs and a fair return are recovered. This obviously implies that whatever the methodology, if what being referred to as objective costs, are recovered they will be significantly higher than presently. This will also contribute to the big bang approach.

2.2 Mapping Total Allowed Revenue to End Use Tariffs

While it is true that averaging is applied in the determination of Allowed Revenue – it is crucially important to recognise that the 'pricing approach' does not end there.

At the risk of over-simplification ³– the MYPD Methodology requires that the costs of Generation and Transmission are to be passed through to Distribution and collected in the form of end use charges and tariffs. It is here that the principles of cost reflectivity and causation at the level of the end user come into far greater focus.

2.2.1 Transmission charges

The Transmission Tariff Code (Version 10) as approved by NERSA provides for the recovery of approved costs associated with owning, maintaining and operating a transmission system (TS) by way of transmission tariffs. Following principles of cost disaggregation, allowable costs to be recovered from TS users are comprised of:

- Network charges
- Losses charges
- Reliability services charges
- Connection charges

³ The treatment of Special Pricing Agreements and imports and exports is not incorporated in this simplified view as is not viewed as material to the point being made.

Network charges and losses charges are recovered from transmission customers on the basis of Notified Maximum Demand (KVA). Reliability charges are recovered on the basis of energy usage scaled to just recover ancillary services costs. The connection charge is based on the cost of assets used for the benefit of the connecting customer.

2.2.2 Distribution Tariffs

In a broadly similar manner, the Distribution Code sets out objectives and principles for pricing and tariff structures for distribution network and retail services. There are well over forty stated objectives and principles provided in the Code. For the sake of brevity we highlight Section 7(1) that speaks to the use of cost drivers in the design of cost reflective tariff structures and the mitigation of risks by way of under and over recovery mechanisms.

"Tariff structures should reflect cost drivers as far as possible. Where tariffs structures do not reflect costs, there is risk associated with mismatching of costs, tariff conversions and changes in volume forecast. The distributor/service provider shall be allowed to mitigate this risk, through appropriate tariff or claw-back mechanisms (for both under or over recovery of revenue) within the revenue requirement.

With Section 7(5) speaking to tariff complexity and the need for a level of aggregation.

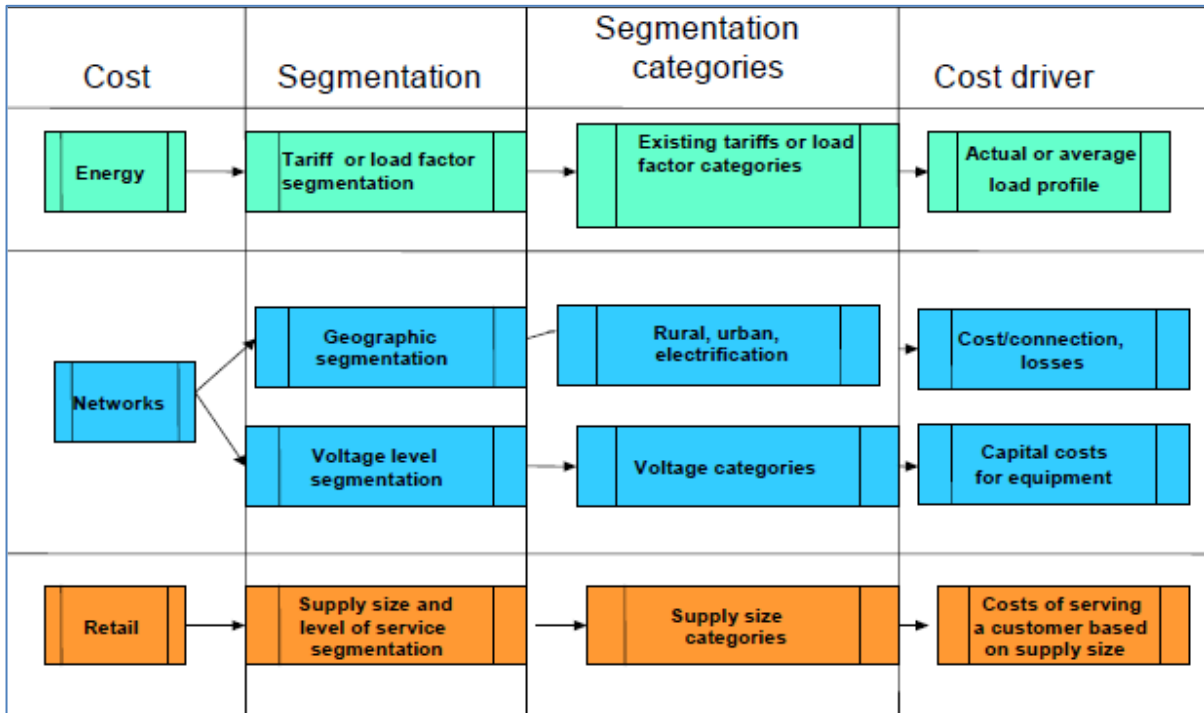
"The tariff structure ultimately used will depend on customer needs, meter capability, billing functionality and logistics, and limitations on tariff complexity. This will cause aggregation of various cost components and cost drivers in the tariff applied.

And that

“,,, electricity supply costs must be unbundled into Energy purchases; Network costs (transmission purchases distribution costs) and Retail / service components.”

The process as illustrated in Distribution Code is shown below.

Diagram 1: Design of Tariff Structure



Source: Distribution Tariff Code, Diagram 2

- Costs are disaggregated at the level of licensed activities.
- Costs are segmented by services provided and customer characteristics.
- Causality based cost drivers are identified that align to segmented costs.

2.3 Migration to Activity Based Costing

Even this modest summary of key elements of the pricing regime gives cause to question the basis on which NERSA has concluded that

“there is a need to migrate ,, from the revenue-based approach to an activity-based costing approach, where different activities are disaggregated along the value chain.” (S.2.3).

The characteristics aimed for in NERSA's proposed migration to an “activity-based costing approach” of disaggregation, segmentation and cost causality are arguably currently in place as provided for in relevant sections of the Grid Code, in Eskom's MYPD application and in the way Eskom's tariffs are designed.

It is important to note that confusion has been created by the use of the ABC concept. It is generally used as a financial concept and has limited use for regulation. It is dependent on which level of activity is being inferred in this consultation document. If the activity being referred to is the electricity value chain, of mainly generation, transmission, distribution and maybe a level of activity below that, then this information is already requested by NERSA in other regulatory instrument (such as the RRM). The more fundamental question is how this information will allow for the development of a new pricing methodology.

Additionally, the use of Activity Based Costing principles is covered in some detail in the Regulatory Reporting Manual (RRM) which sets out the approach to be applied in allocating costs as part of the MYPD Methodology as described below:⁴

"The allocation (assignment and attribution) of costs should ensure that separation and no cross-subsidisation occurs between regulated and non-regulated lines of business and between regulated businesses themselves, products or services. The cost of each activity should be distributed among the business units based on direct assignment when possible, and based on cost drivers when not".

More generally speaking, it is surprising that so little attention has been given to the RRM having in mind the concern over asymmetry of information and the ability to verify the prudence of costs referred to in the Consultation Paper. In fact, the RRM sets out in considerable detail the way in which costs are to be reported for the separate licensed activities.⁵

2.4 The Case for Overhauling the MYPD Methodology

Section 1.5 of the Consultation Paper speaks to the circumstances in which the Review has been initiated whereby:

⁴ Op cit, Section 2.2

⁵ NERSA, *Regulatory Reporting Manual Volume 1: General Regulatory Reporting Procedures and Administrative Matters Version 2*. Government Gazette, 21 October 2016

“a thorough stakeholder consultation process highlighted the failings of the current MYPD methodology and provided evidence and guidance on the need to overhaul it.”

And that

“The enemy in the current electricity pricing approach is the “averaging”, which results in inefficiencies, cross subsidies and socialisation of costs, which is central in revenue determination. The proposal is (sic) effectively aims to eliminate all these.”

But there are two points we wish to highlight here:

- a) Taken at face value, concern over the failings of the pricing methodology as represented in Section 1.5 of the Consultation Paper seem to centre around issues most closely associated with the structure of charges and tariffs – rather than the methodology employed in the determination of allowed revenue (efficient costs + return). It follows that the focus of this review is better placed on the review and potential revision of elements of the Grid Code addressing the structure of charges and tariffs.
- b) The aggregation of costs in the build-up of the revenue allowance found in the MYPD Methodology is also a characteristic of pricing methodologies NERSA applies in the determination of petroleum pipeline tariffs and allowed charges pertaining to storage and loading facilities. However, we are not aware of those methodologies having been found by NERSA to be entirely flawed and in need of replacement.

The aggregation of costs is also found in the regulatory approaches of the Regulating Committee for ACSA and ATNS in setting Airport Company South Africa's permitted charges, and the Ports Regulator of South Africa in pricing regulated ports services, and is ubiquitous when looking at cost of service regulatory regimes globally.

In stark contrast, the Consultation Paper does not offer any real-world examples in which NERSA's proposed pricing methodology has been applied. Subjecting the electricity supply industry to untested and untried regulatory “methods” can only work against the predictability and stability of the regulator regime.

With the above in mind, it seems only reasonable that NERSA carry out a study that examines and reports on the experience of other jurisdictions that have applied the types of pricing mechanisms alluded to in the Consultation Paper. This would offer important information on:

- circumstances in which the pricing methodology was applied;
- observed strengths and weaknesses of the approach;
- implementation and administration of the approach;
- unintended consequences; and
- modifications that may have been carried out after initial implementation.

2.4.1 Assumptions on sales volumes have a role to play

“NERSA concern on sales volume variance is misplaced” (Prof Eberhard – NERSA Consultation workshop, 18 October 2021). Eskom has demonstrated on many occasions that neither Eskom nor Municipalities have control over sales volumes and both rely on customer information to develop such a forecast. Eskom undertakes a detailed process to determine the projected sales. NERSA also undertakes its independent process to project sales.

Regarding declining sales, analysis indicates that to the degree that customers are opting for self-generation, it is not because of too high Eskom prices but mainly because of inadequate and unreliable supply – which ironically would inevitably result from chronically sub-cost-reflective tariffs, as also Professors David Newbery and Anton Eberhard stated in their report to government. Prof Anton Eberhard's further research confirmed that this is empirically observed in most if not all countries where electricity tariffs are artificially suppressed to chronic sub-cost-reflective levels, and that in addition the consequence is then that consumers in such countries, in effect, experience higher cost of electricity than even the cost-reflective grid price, given that they have no option but to self-generate at extreme costs (per the World Bank).

If prices are 'too high' to some consumers it will not be Eskom consumers (for which it is becoming more and more acknowledged that the prices are extremely low by any credible benchmark reference) but municipal customers, many of whom pay much higher tariffs to their municipalities, which tariffs are approved by NERSA annually.

It is obviously inconceivable that the MYPD methodology or NERSA or Eskom or government could 'set' actual sales volumes. This is obviously an outcome of a myriad of economic factors such as GDP growth, investor confidence, commodity cycles, disinvestment, de-industrialization, etc. Hence the MYPD methodology in line with any globally accepted sound economic regulatory practice, is not silent on sales volumes but factors it into the revenue and tariff equation as an essentially uncontrollable (to the utility) variable.

The tariff needs to be restructured to ensure that cost reflectivity at a tariff level is migrated towards to mitigate volume risk. This is in the hands of NERSA to address through allowing and encouraging the restructuring of tariffs so as to enable recovery of the fixed costs through appropriate fixed charges from all customers that are grid-tied, who will still rely on the grid for back-up.

NERSA is empowered to make key decisions for the determination of infrastructure investment in the electricity industry. NERSA concurs that at least 65% to 70% of Eskom's efficient costs are fixed costs. The basis of these fixed costs are based on approvals made by NERSA. With regards to Transmission and Distribution infrastructure, Eskom implements in accordance with the NERSA Grid Code and Distribution Code requirements. Generation requirements are determined by the Integrated Resource Plan (IRP). It is assumed that NERSA, as any stakeholder, provided input into the finalisation of the IRP. When the Minister of DMRE makes a determination in terms of the IRP, NERSA is required to evaluate the requirement of particular generating capacity before concurring on the Minister's determination. After concurrence from NERSA, the DMRE Minister determines the procurement process to be followed. Once the procurement process has been finalised, NERSA is required to license entities that will provide the generating capacities. Included in the licensing process is the financial viability. Thus it is submitted that NERSA has ensured that when a revenue application is made, the majority of the basis of the costs (fixed costs) have withstood the rigour of various NERSA analysis processes. When a revenue application is made, it is based on the previous approvals already made by NERSA.

NERSA, in its revenue determination, also determines the sales volume to be assumed. NERSA undertakes an independent analysis to make this determination. In making this determination, NERSA evaluates the price elasticity impacts.

As sales volumes increase or decrease, there would be a concomitant increase or decrease in variable costs, but not necessarily fixed costs. The key variable costs for the electricity industry are related to primary energy costs. Primary energy cost variances due to lower sales have been included in each of the primary energy cost elements in the RCA balance computation. Fixed costs include interest and debt repayments which are included in the returns and depreciation building blocks of the allowed revenue for regulatory purposes.

The RCA mechanism that corrects for electricity demand under/over estimation is not mechanism to 'restore' sales volume and revenue to the estimated level, but rather is a mechanism to correct for such under/over-recovery of fixed cost caused by variances between estimated demand and actual demand, which it achieves by adjusting estimated sales volumes to align to what actually happened, and recalculates what price would have been on that basis, and thus revenue shortfall to be recovered through RCA. It has to be recognised, like NERSA, Eskom does not have control over such volume variances, whether higher or lower, as this is dependent on many factors outside of Eskom's control such as economic climate, commodity prices, civil unrest and, COVID.

NERSA makes a decision based on sales volume that NERSA determined to be reasonable, according to its analysis. If the revised (lower) volumes had been deemed to be reflective of what could be achieved for each of the financial years, there would have been two different outcomes. The first is that the resultant price (in c/kwh) would have been higher – because the allowed revenue would have been recovered over a smaller volume of sales. The reason for the higher price is due to the recovery of the fixed cost elements. The variable cost elements are netted off as part of the operating costs. Thus consumers are being allowed a subsidy in the first instance, since it was assumed that the fixed costs would be recovered over a larger sales volume. The variance is then recovered many years later, when NERSA allows for the recovery of the RCA balance. The opposite would also be true if volumes increased, resulting in lower price adjustments.

It has been demonstrated that a 1% increase or decrease in volume (which presently equated to approximately 2 TWh) does not result in a significant change in price of electricity. It is thus surmised that when NERSA has to implement its mandate in accordance with the Electricity Regulation Act, with regards to allowing a licensee to recover efficient costs and a fair return, the focus should be on analysis of efficient costs and a fair return.

Therefore if NERSA wants to place all volume risk on the utility (including municipal distributors), the only way the utility can mitigate this risk is to ensure that tariff charges that recover fixed costs are not volumetric. This will impact low load factor customers the most. The likely outcome would be a substantial increase in prices. Eskom has been trying to migrate towards most cost reflectivity at a tariff level. An option to consider is for customers (especially larger customers) to take accountability for the forecasts they provide and if volume risk is fully placed on the utility, then this risk would have to be passed onto the customers that provide such information.

2.4.2 Average price is determined by NERSA for communication purposes

For communication purposes, NERSA determines an average price of electricity in c/kWh. This average price is never charged to any electricity consumers. It only used to increase tariff in accordance with NERSA's own ERTSA methodology.

2.4.3 Tariff development and its relationship with cost

The approval of costs and the design of tariffs are two separate and sequential processes. The two are interchangeably used in the NERSA consultation document. Tariffs do not determine the costs; they recover the allowable costs and cannot provide more revenue than that approved by NERSA (in a regulated environment).

Tariff design is based on, and starts with a revenue determination, thereafter a cost-to-serve (cost-of-supply) allocation of allowed functionalised costs and finally a restructure or introduce new tariffs to reflect updated cost and cost drivers. In the absence of an update or restructure of tariffs, tariff category increases are used for year-on-year adjustments. Municipalities have to develop an interim revenue requirement in order to conduct a cost to supply study.

Tariffs are therefore not designed based on the average price announced by NERSA, they are an outcome of the regulated cost plus return decision. This decision on regulated cost is a justification of prudent costs and allowable return. Only once the cost plus return decision is known, the revenue and approved volumes are used in a cost-to-serve exercise to allocate these allowed costs and from this tariffs are designed. The cost-to-serve is not a cost justification process, it is a cost allocation process for the purposes of determining end-use retail tariffs.

The Eskom submission to NERSA for the approval of tariff structural changes or new tariffs, is a separate process from the annual tariff adjustment process. This follows that the approval of changes in tariff structures or new tariffs is required before they are adjusted to reflect a new financial year's price level. Further, the NERSA regulation, ERTSA directs the determination of year-on-year tariff category increases requiring that annual increase submissions are exclusive of changes to tariff structures and limits the approval to a change in tariff rate levels through average price increases.

The steps to determine and design tariffs are well documented internationally as a sequential process.

- The first determines the required level of annual revenue, typically known as the revenue requirement. This determination is crucial in understanding what the holistic, efficient costs including a fair return would be required by the utilities. This is also aligned to NERSA requirements in meeting its mandated role of allowing an efficient licensee to recover its efficient costs and a fair return. There are ample opportunities for NERSA to analyse, benchmark and thereby determine what this should be. It also follows that it is a matter of how NERSA undertakes its role within a defined, internationally recognised set of rules.
- The second phase which is the cost to serve - apportions the revenue requirement using functionalised divisional costs among justifiable and segmented customer categories, using cost drivers such as customer-related costs, demand-related costs and energy-related costs cost to serve
- The third phase where the tariffs or rates, are designed (structures and level) in order to collect the allocated cost from each customer category. This process takes into account, guided by national policy, the Codes and NERSA rules, sophistication of customer needs, metering, affordability, impact of changing from the existing tariffs, revenue risk (departing from the cost driver) and fairness.

2.4.4 Tariffs cannot determine costs

Tariffs methodologies described in the NERSA consultation document, presupposes that tariffs and tariff structures are used to determine costs (price and cost are confusingly used interchangeably). For example, there is discussion on how generation costs should be disaggregated into how they serve different customer categories. Generation costs are costs

based on their assets and operating costs and not based on a customer's profile. How these are then charged to customer is a tariff exercise, and this cannot be based as proposed by NERSA on the type of use.

Tariffs cannot be designed based on individual customer usage, unless such tariffs are unique to a customer under a market based approach. Even then, this would significantly increase the number of tariffs and would require NERSA to approve such individualised tariffs for each and every customer as required by Law. This in turn would mean that all other tariffs would have to be adjusted to come back to the revenue requirement. A change to one tariff or tariff category, means an equal and opposite change to another tariff category.

It is for this reason costs are generally pooled into homogenous and identifiable cost categories when doing a cost-to-serve exercise (after the cost have been approved). Any results from this exercise leading to tariff changes always mean someone will pay more and someone will pay less.

More detail is provided on these processes below.

2.4.5 The NERSA Cost to supply framework

On 29 October 2015, the NERSA approved a Cost of Supply (COS) framework to be used as a guideline by all Licensed Electricity Distributors for conducting COS studies and licensees that had the ability could expand on the framework to a level that met their specific needs.

The aim of the NERSA COS framework was to satisfy the requirements of the Policy Position 23 of the Electricity Pricing Policy (EPP) of 19 December 2008 that requires Distributors to conduct a Cost of supply study at least every 5 years using a NERSA approved standard to reflect changing costs and customer behaviour.

The COS framework provides the NERSA standard for Licensed Electricity Distributors allocate costs with the goal of rate setting informed by an embedded cost approach that:

- Recognises a revenue requirement as the level of costs to be used in the cost allocation. The revenue level is to satisfy the EPP Policy Position 1 that for a level that covers the full cost of production including a reasonable risk adjusted margin or return on appropriate asset values. In the absence of a revenue requirement as is the case for municipalities,

an interim revenue requirement that is the sum of all costs anticipated in the application is to be used as a basis for the cost of supply study.

- Requires Licensees to arrange costs along major operating functions of a licensee to facilitate a determination of customer groups contribution to the costs. This process referred to as cost functionalisation separates and arranges costs along production/generation, transmission, distribution or customer-related functions.
- After the cost functionalisation Licensees need to ensure that the arranged costs are further disaggregate into sub-groups in a manner that clarifies the relationship as a measurable cost-defining characteristic of rendering the service; the cost classification. Consequently, this break-down or classification differentiates fixed from variable costs, demand-driven, usage or energy and customer / retailing-related costs.
- The cost allocation is the final process of the framework providing unit costs for use in rate determination or in the development or update of tariffs. The classified costs inform the cost allocation to customer groups separately for energy, transmission, distribution networks and retail using cost drivers. The NERSA cost allocation methodology is shaped to allow for a transparent view of the electricity value-chain by ensuring:
 - Energy consumed is a cost driver to allocate energy costs as it varies energy costs by time of use and incorporates the cost of network losses associated with consumption.
 - Customer demand is a cost driver to allocate network costs as network costs are influenced by the demand level. The costs classified under network costs are network capital costs, the operations and maintenance cost of networks, demand purchase cost (if applicable) and the wires component of the purchase cost (if applicable). The use of the average and excess methodology to allocate network costs is advised since it allows for the allocation of network costs following that if a customer group uses a specific network asset, the customer group is included in the allocation of the cost of the asset group.

2.4.6 Cost to serve

This process starts with the approved cost plus return (revenue) and then costs are allocated as follows:

- Classified costs are allocated to customer categories

- based on applicable cost drivers
- using an appropriate cost allocation method
- to produce unit costs per customer category/cost type

Cost justification is done by Eskom through the NERSA rules and approval process, where Eskom motivates revenue to cover return, depreciation, and operating cost, and NERSA decides on the amount to be approved through the allowable cost recovery process. The approved revenue requirement and volumes are the values used in the cost-to-serve study exercise.

The tariff design uses cost units from the cost-to-serve study. The cost-to-serve study is an embedded cost-of-supply study allocating the Eskom allowable revenues from an MYPD decision related to Eskom's standard tariffs by customer categories that are segmented by supply voltage and location density.

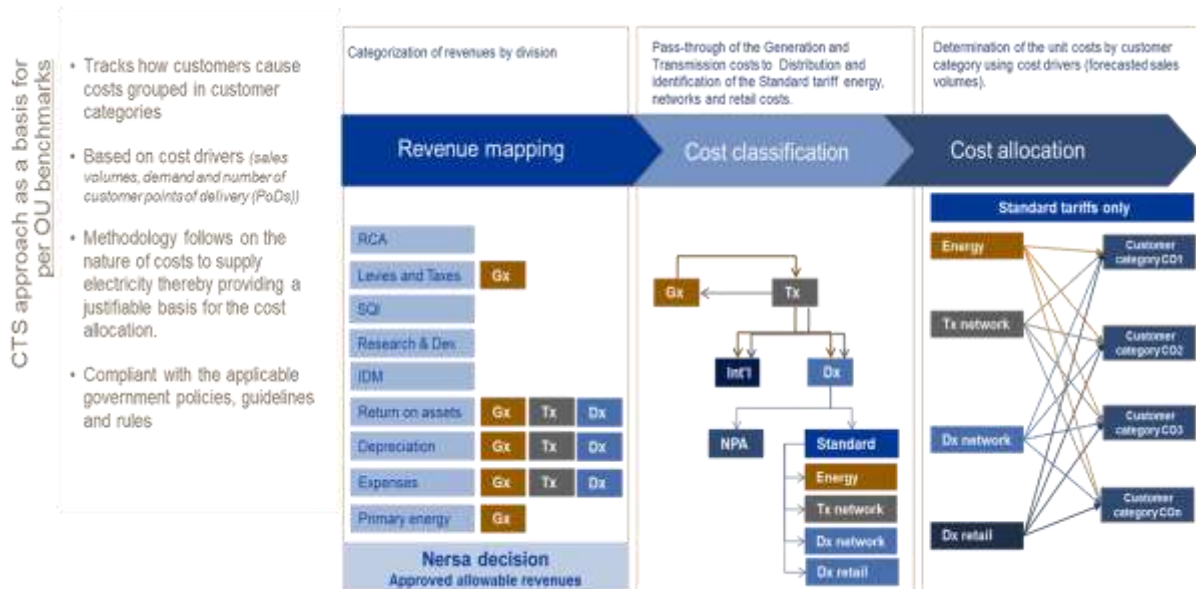
The cost-to-serve study cost allocation is guided by a cost causation principle; that is, it tracks how each customer category contributes to the costs to supply electricity based on its consumption and demand. The cost drivers used in the cost allocation are the volumes used in the NERSA MYPD decision for the costing year, that is, the sales in kilowatt-hours, the demand (utilised capacity, maximum demand, and chargeable demand), and the number of customer points of delivery (PODs).

The cost-reflective unit costs from the cost-to-serve study are then converted to measurable units to reflect cost drivers.

The following are the most common cost drivers in the electricity business:

- R/customer/month or R/customer/day charge - typically for customer service and administration costs.
- R/kVA - typically for network or capacity based costs.
- c/kWh - typically for energy costs, return and taxes.
- c/kvarh - reactive energy costs.
- R/Amp - to recover energy or network costs.
- Energy loss factors for energy loss costs.

Figure 1: Illustration of Cost to Serve study



2.5 The tariff design process

The type of price components put together in a tariff package is the tariff structure. The ideal tariff structure would therefore follow the cost structure. A cost-reflective tariff structure has all cost components reflected separately and charged according to the appropriate cost driver per appropriate rate unit. Eskom supports the unbundling of costs in the design process as far as practically possible to determine the charges used to recover those costs and ultimately form the tariff structure.

Tariffs are designed to provide current and future price signals that are forward looking, but still designed to recover current approved revenues. Rates must satisfy numerous objectives, some of which may be in competition with others. Generally and universally accepted and still relevant today are the following pricing principles set out in Professor James Bonbright book Principles of Public Utility Rates, summarised as follows:

- Sufficiency: Rates should be designed to yield revenues sufficient to recover utility costs.
- Efficiency: Rates should provide efficient price signals and discourage wasteful usage.
- Fairness: Rates should be designed so that costs are fairly apportioned among different customers, and "undue discrimination" in rate relationships is avoided.

- d) Customer acceptability: Rates should be relatively stable, predictable, simple, and easily understandable.

The type of price components put together in a tariff package is the tariff structure. It is supported by the ideal tariff structure would be unbundled to follow the cost structure. However, tariff design is not just about reflecting costs, it is also about reflecting price signals that drive consumption behaviour to optimise system and cost efficiency

A cost reflective unbundled tariff structure has all cost components (energy, networks and retail costs) reflected separately, and charges are raised using the most appropriate tariff charge type needs to be established. The tariff structure to be used may be dependent on:

- Revenue and volume risk (departing from the cost driver)
- What pricing signals need to provided
- Sophistication of customer needs
- Metering – can it be measured?
- Affordability – do subsidies need to be accommodated
- Impact of changing from the existing tariffs.
- Cannot be discriminatory

Tariff structure challenges include:

The most cost-reflective tariff will reflect in its structure and level, the cost drivers/categories as accurately as possible, but this tariff structure is complex.

- A tariff may be cost-reflective on average, per customer class or even per customer and the more averaging the less cost-reflective to a particular customer, but the simpler the tariff becomes.
- It is not possible to have total cost reflectivity per customer as this would significantly increase the number of tariffs and therefore similar or homogeneous costs are always pooled
- Meter capability, billing functionality, logistics and customer response force aggregation when reflecting the various cost components and cost drivers in a tariff.

A cost reflective tariff structure to recover electricity costs will typically contain:

- Energy charges – including a signal to reflect time and seasonal variance to reflect system constraints (not type of use) and in future a generation capacity related charge to reflect the cost of providing standby capacity
- Transmission network and ancillary service charges
- The Distribution network charges
- Retail (service and administration) charges
- Differentiation to take into account:
 - Geographic location
 - The voltage of the supply.
 - The electrical (technical) losses.
 - Reactive energy support.
 - The density of the network to which customers are connected.
 - The load factor/profile.
 - The size of the supply and the services being provided to the customer.

Eskom currently has largely unbundled tariff structures for most customer categories and the extent of unbundling depends on the customer category. Eskom in its 2020 retail tariff plan submission provided NERSA with extensive detail on further unbundling based on a new cost-to-serve study and how the proposed tariffs and tariff structures would be derived. The Distribution Tariff Code in provides a useful explanation on tariff design principles, which are aligned to the EPP. It is noted that in the Consultation paper that no consideration was given to this process.

A point to be noted as well, is that Eskom already has NERSA approved wheeling tariffs and based on a non-discriminatory approach, these tariffs are applicable to all users of the grid, whether supplied by Eskom or by a third party. These tariffs are our unbundled network use-of-system charges.

2.5.1 Impact on consumers to be considered before tariff adjustments are made

As part of any changes in tariffs, it is essential to first determine the impact of any changes before making the final decision. The revenue (efficient cost and reasonable return) will be recovered through various tariffs. When changes are made to tariffs there is a likelihood that customer groupings will be impacted. It is likely that certain customers would be positively impacted and certain customers would be negatively impacted. This also points to the merits of phasing-in of any changes. Any sudden change will likely to have severe impacts that could result in changes that will require particular attention. A big bang approach will likely to have catastrophic impact.

In addition, cross subsidies are an essential element of managing the impact on vulnerable sectors, such as poor residential customers. The cross subsidisation, as a policy decision, has been included in the EPP. The first element in this section, that seem to be lacking in this consultation paper, is the need to undertake impact assessments before making any decisions. From what could be inferred in this consultation paper is that residential customers are likely to see an overnight increase of between 30% to 50%. The second element, is that indications are that the consultation paper indicates that cross subsidies are not necessary. Cross subsidies is a policy position included in the EPP. The removal of cross subsidies are likely to further contribute to impact on the residential sector. Eskom's developmental role and that of other utilities is not addressed in the Consultation paper.

There are always a balancing of conflicting priorities to be considered. Choices have to be made between the winners and losers meaning that whenever tariffs are changed someone will pay more and someone will pay less. Most concerning is that the Consultation Paper on the concept of "type of use" implies that industrial customers receive the allocation of the lowest cost electricity generation and that all other customers will pay for variability. This would have a significant negative impact on traction, agriculture, residential, commercial and most importantly Eskom's municipal tariffs. It is not clear in the Consultation Paper how the concept of marginal pricing will flow through into tariffs and ensure adequate recovery of costs.

In conclusion to this section, we wish to highlight the following passage taken from NERSA's Guidelines for the Determination of Municipal Tariffs which we commend;

“In the absence of competition, regulators may select from a range of methodologies to regulate the industry. All these options have various advantages and disadvantages. Regardless of the method of regulation or price formation, it is essential that an efficient and prudent licensee should be able to generate sufficient revenues that will allow it to operate as a viable concern, now and in the future. Moreover, it is important that the regulated business is able to attract reasonably priced finance in order to maintain, refurbish and grow its infrastructure and provide services at a reasonable cost. As a result, tariffs must be set at a level that will not only ensure that the utility generates sufficient revenues to cover the full costs (including a reasonable margin or return), but will also allow the utility to obtain reasonably priced funding”.⁶

⁶ NERSA, Reason for Decision, Determination of the Municipal Tariff Guideline and the Revision of Municipal Tariff Benchmarks for the 2021/22 Financial Year. (S.3.3)

3. RESPONSE TO QUESTIONS ASKED OF STAKEHOLDERS

3.1 Industry Transformation

Stakeholder Question 1:

- a) Stakeholders are requested to comment on the transformation of the Electricity Industry and its implications from the stakeholder's perspective, especially:
- a. what is driving change; and
 - b. their expectations from the transformation.
- b) What are your views on electricity market structure, and what would be the alternative structure?
- c) The reasonableness of calculating average price based on the forecast sales.
- d) The fairness of allowing licensees to claw back lost sales through increased tariffs for consumers.
- e) What alternative approaches to determine prices should be considered, that:
- a. are not dependent on licensee forecasted sales; and
 - b. make the licensee carry the sales risk and not consumers

Market structure (a and b)

While any pricing methodology must be fully aligned to the overarching regulatory scheme of governance its resides in – and it is our view that the issues of market structure canvassed in the Consultation Paper are well outside of NERSA's mandate, and we see no purpose to speculating about future outcomes or alternatives within the context of this review of pricing methodologies.

Of course, should the ERA be amended in the near future, any implications for pricing falling from such amendments would need to be incorporated in the review of pricing methodologies. This would result in reason to favour incremental and properly thought out review of the pricing methodology. Such process would allow for prioritisation of issues that could be feasibly addressed in a reasonable amount of time, while allowing for more substantial revision to take place if/after mooted legislative and policy changes are effected.

Average price, forecast sales, and claw back (c and d)

On the “reasonableness of calculating average price based on the forecast sales” we first wish to point out that the calculation of average unit price serves is a construct employed to

administer tariff adjustments under the ERTSA, and does not determine tariff levels or the structure in which tariffs are applied.

Importantly, the 'average price' referred to is in fact the average unit cost falling from Allowed Revenue and forecast sales volumes applying to Standard Tariffs as determined by NERSA. Furthermore, the Distribution Code (S.7.2) states that "tariff charges (rates) shall be calculated based on the approved revenue requirement, volume forecast for demand and energy and customer numbers."

Rather than speculating on the "fairness of allowing licensees" claw back under recovered revenue we point to a short list of relevant elements that should be considered

“,,, (the)setting or approval of prices, charges and tariffs and the regulation of revenues -

(a) must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return; (ERA S.15(1))

And as provided for in the Distribution Code:

“Tariff structures should reflect cost drivers as far as possible. Where tariffs structures do not reflect costs, there is risk associated with mismatching of costs, tariff conversions and changes in volume forecast. The distributor/service provider shall be allowed to mitigate this risk, through appropriate tariff or claw-back mechanisms (for both under or over recovery of revenue) within the revenue requirement. (Distribution Code S.7.1)

Moreover, similar claw back provisions are found in other sectors that NERSA has regulatory oversight of and are commonly observed in international practice.

3.2 Activity Based Costing

Stakeholder Question 2:

Stakeholders are requested to comment on the following:

- a) Use of activity-based costing for regulatory price setting.*
- b) The implementation of the ABC approach in the SA Electricity Industry within:
 - a. the current electricity industry structure; and*
 - b. a future disaggregated Electricity Industry.**

Use of ABC for regulatory price setting (a)

Consistent with Section 1.5.1 of the Consultation Paper, Activity Based Costing is based on the two fundamental principles of cost separation (i.e. disaggregation of directly attributable costs) and cost allocation i.e. assignment of common costs). To be noted is that this level of cost disaggregation has been a feature of the MYPD since its inception in 2006.

The application of these principles to regulatory application is most often observed in relation to the allocation of costs between regulated and non-regulated activities of the business, and in allocating corporate overheads across various business units. This calls up two points warranting comment.

First, non-regulated activities and corporate costs represent a relatively small proportion of Eskom's total cost to serve, and fine tuning this allocation across the licensed activities – while having merit – is hardly cause for an entire re-work of the MYPD Methodology.

More importantly, costing principles are covered in some detail in the RRM:⁷ The RRM requires that the fully allocated cost (FAC) approach be employed in development of cost separation (i.e. disaggregation of directly attributable costs) and allocation (indirect, or common costs) methodologies.

- Direct assignment of costs among licensed activities is preferred where practical to avoid cross- subsidisation.
- Common costs are allocated on the basis of cost causality, with observable 'cost drivers' identified having the aim of providing objectivity and transparency to the allocation of costs.

Regulated and non-regulated activities

Eskom is structured in a manner well aligned to the regulatory environment that it works within. Importantly - licensed business activities carried out by Eskom are fully ring-fenced from non-regulated business activities so as to avoid cross-subsidisation.

- The overwhelming proportion of *non-regulated business activities* associated with Eskom Holdings are placed within legally separated (i.e. standalone) subsidiaries as defined

⁷ Op cit, Section 2.2

under the Companies Act. There is no material cost sharing between Eskom's regulated licensed business activities and the activities of subsidiaries. Moreover, there is strong separation of regulated and non-regulated business activities, with transactions carried out on a commercially based arm's length basis.

Shared services/corporate overheads

Where possible, expenses directly relating to shared services are charged directly (i.e. internal/ interdivisional charges) to the division / business unit receiving the service using specific cost allocators (e.g. headcount, number of purchase orders etc.) and are commonly referred to as 'direct overheads'. Those costs that cannot be directly charged – i.e. what is deemed 'indirect overheads' is allocated / assessed using a suitable allocator.

The allocation of shared services / corporate overheads is continuously being refined to ensure that where possible these costs are assessed using the most appropriate allocators.

As part of the RRM process, Eskom has developed an initial Cost Allocation Model as prescribed in those guidelines.

"The allocation (assignment and attribution) of costs should ensure that separation and no cross-subsidisation occurs between regulated and non-regulated lines of business and between regulated businesses themselves, products or services. The cost of each activity should be distributed among the business units based on direct assignment when possible, and based on cost drivers when not".

Efforts to refine the Cost Allocation Manual and provide more details on how costs are allocated have not come to fruition, as it has been dependent on NERSA clarifying a number of 'grey areas' contained in the RRM Manuals. Eskom as part of its half-yearly and yearly Regulatory Financial Report (RFR) submissions has continuously raised these issues and NERSA has also alluded to the fact that the RRM manuals would be reviewed in order to cater for the learnings that have resulted over the years since the inception of the RRM.

It is therefore of concern that the coverage and requirements of the RRM have not been recognised or compared to the approaches proposed in the Consultation Paper. Moreover, Section 5.1 of the Consultation Paper describes the proposed application of Activity Based Costing (ABC) as the:

“migration from the revenue-based approach to an activity-based costing approach to derive cost reflective tariffs to give effect to the tariff principles in section 15(1) of the ERA” by disaggregation of “generation (Gx), transmission (Tx), distribution (Dx), system operations (SO), market operations (MO), trading (Td), other ancillary services (AS)”.

The use of the ABC terminology by NERSA in the Consultation Paper is also very confusing as it seems to suggest that it is to account for the cost of a particular function e.g. Generation as opposed to the costing of activities in its lowest form. The costing of a particular function (e.g. Generation) already exists in the current methodologies.

With the above in mind, Eskom requests that NERSA provide guidance on:

- whether the new costing approach proposed by NERSA is meant to overlap or supersede the RRM; and
- whether the new approach is meant to apply solely to Eskom and the MYPD, or to all sectors overseen by NERSA as the case for the RRM?

3.3 Demand Analysis

Stakeholder Question 3:

- a) *Stakeholders are requested to comment on the format to collect the demand analysis information.*
- b) *Is this proposed information adequate to achieve activity-based costing regulation? If not, what are other alternative types of information?*

Format to collect demand data (a) and (b)

A request is being made by NERSA to “follow the electron”. It is unclear why an **impossible** request is being made. A thorough understanding of the manner in which an electricity works needs to be appreciated. It is submitted that an electricity system cannot be directly compared to other commodities. Electricity is unique and requires an appreciation of the complexity that goes with the management and balancing of the system. In addition, if this information were to possibly be made available, no indication is given on the metering requirements, the increased investment requirements, as well as any cost benefit analysis. It is unclear how this information could be useful in determining how utilities could recover their efficient costs and

a fair return. This has not been done anywhere else in the world and no other jurisdiction is even trying to do so.

The nature of an interconnected power system is such that all producers of electricity and all consumers of electricity participate in the exchange of power simultaneously. At its most fundamental, the entire power system is oscillating in synchronism and power is produced by all the generators and consumed by all the consumers at the same moment in time.

In the case where a single generator supplies a single consumer through a single transmission line, it is possible to attribute all the energy produced, consumed and transmitted to the generator, transmission line and consumer respectively. However, in an interconnected/meshed transmission network, power flows simultaneously from multiple generators through multiple transmission circuits to multiple consumers and it is not possible to quantify which portion of power flowed from which generator to which consumer through which transmission circuits.

A further complication arises due to the dynamic behavior of consumers and the generators who vary their demand requirements and generated power continuously in time. This gives rise to an almost infinite number of circumstances in which different generators supply different consumers through different transmission lines.

As demand for electricity increases, more expensive generation must be dispatched to meet this demand. The last generator dispatched does not exclusively supply the last consumer requiring power but both now participate, simultaneously, with all other generators and consumers at that moment in time. From the above, it is clear that no consumer or group of consumers can be mapped or be deemed to be supplied from any generator or group of generators. Similarly, no generator or consumer can be mapped to or deemed to be supplied via specific transmission lines in the interconnected transmission network.

In the case of a bilateral trade between a generator and a consumer that takes place "outside the market"; both parties in the bilateral agreement place power onto and consume power off of the power system simultaneously and, apart from some incremental transmission costs, remain neutral to the costs borne by other market participants using the power system. However, all market participants using the power system simultaneously, drive the price of the

total generation upwards and all participants at that moment in time contribute equally to the increase in the cost.

Market participant do have the freedom to choose when they will consume power and may plan appropriately. In the case of continuous industrial processes, this choice may not be feasible but they enjoy a cost benefit of consuming during low demand periods.

In essence the stakeholder question being asked cannot be answered.

3.4 Generation Costs

Stakeholder Question 4:

- a) *Is this information adequate to achieve activity-based costing regulation? If not, please provide an alternative*
- b) *What would be an appropriate tariff cost build-up for a generation business to make a return on its investment?*
- c) *Stakeholder are requested to comment on the appropriateness of the approach proposed by NERSA to set the generation component of the price of electricity.*
- d) *Which international benchmarks and best practices should NERSA consider – both in terms of type and sources.*
- e) *How should NERSA ensure that only efficient costs from the distribution utilities are recovered?*
- f) *Is the list of costs identified by the Energy Regulator sufficient, if not suggest the other relevant costs?*

Information requirements (a)

Without defining what is entailed by 'generation activity-based costing regulation' it is difficult to comment on the data needed to achieve the intended outcome.

At this point we note the need to refer to the requirements of the RRM (albeit its shortcomings which have continuously been highlighted to NERSA) in which a considerable amount of resources have gone into its development. We find it disheartening after the level of effort Eskom and other licensees have devoted to that work for it to seemingly be made redundant to this new review of pricing methodologies without a detail analysis of where it has (presumably) failed in the eyes of NERSA.

Cost build-up for a generation business to make a return on its investment (b)

The build-up of generation costs **needed to obtain a reasonable return** at the level of the licensee is rather straight forward (with caveats):

- Primary Energy (i.e. fuel, transport, and associated costs)
- Non-Eskom generation (Power Purchases)
- Use of transmission system charges
- Generation operating and maintenance costs
- Administrative and central costs
- Asset retirement costs
- Environmental compliance costs
- Depreciation and amortization of regulatory assets
- Remuneration on invested capital

***NB.** A caveat to the passage above is in regard to the ex-post treatment of generation costs. Given the nature of fuel costs which are largely determine don an arm's length basis, and which are notoriously difficult to predict, it is common practice to apply fuel cost adjustment mechanism to the ex post recovery of efficient costs of generation. Eskom would be pleased to provide a review of international practice in this regard if given adequate time for such response.*

Continuing with the questions explicitly asked of stakeholders, as an asset intensive activity the cost of capital as expressed in terms of the Weighted Average Cost of Capital (WACC), and valuation of the regulatory asset base to which it is typically applied is of crucial importance in achieving a reasonable return on generation investment. This entails a further level of detail in regard to:

- Method employed in valuation of regulatory assets
- Criteria for recognising assets into the Regulatory Asset Base (i.e. qualifying assets)
- Treatment of inflation in calculation of regulatory depreciation (e.g. indexing the asset base if using a indexed adjusted WACC).

- Treatment of inflation and tax in the WACC
- Cost of debt, return to equity, and gearing as inputs to the WACC

Proposed approach to generation pricing (c) and (d)

Eskom is of the view that Section 15(1)(a) of the ERA provides the basis in which to assess any approach to generation pricing, charges, or tariffs in that it “must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return”.

The concept of base-load, mid-merit and peaking technologies and profiles can no longer be applied in an industry where renewables generators with very varying and intermittent generation profiles and battery storage are expected to play a bigger role. In addition, this idea/concept is completely incompatible with a competitive market which is technology agnostic. A competitive market will change the definition of peak, standard and off-peak time periods not based on generation technology but on periods of high, medium and low marginal prices.

Marginal cost

There are a number of different definitions regarding marginal cost – each one valid in a particular context and for a particular purpose. However the consultation paper does not clarify which type of marginal cost is envisaged.

For example, the different types include:

- ‘Short run marginal cost’ (SRMC), which reflects mainly the variable or fuel cost and is used to determine the cost of additional electricity production volume in the context of sufficient generating capacity being available to meet such increased output;
- ‘Long run marginal cost’ (LRMC), which includes fixed operating cost as well as the levelised capital cost of the incremental generating capacity that would needed to meet such increased output;
- Incremental or avoidable ‘short run’ marginal cost, which includes only the true incremental cost of also the fuel supplies thus excludes fuel cost related to fixed-offtake fuel contracts;

These different definitions are appropriately used in specific contexts:

- 'Short run marginal cost' (SRMC) is used when the generating system temporarily reflects surplus capacity and additional production output could be achieved from the existing capacity without needing to expand the capacity.

This situation would usually be temporary and would cease when either the demand increases and/or the supply decreases due for instance to scheduled decommissioning of existing capacity. Consideration should still be given to whether any fixed-offtake fuel contracts should be taken into account;

- "Long run marginal cost" (LRMC) is used when the generating system reflects an equilibrium between supply and demand. In such a case, to meet increased demand would require the expansion of generating capacity, thus the cost for additional production output would include the fixed operating cost of such additionally required generation capacity as well as the levelised capital cost of the incremental generating capacity that would be needed to meet such increased output.

This is the appropriate version of marginal cost that would be used to simulate the outcome of an efficient market, given that by definition an efficient market reflects perfect equilibrium between supply and demand;

- Incremental or avoidable 'short run' marginal cost is used when fuel supply contracts contain fixed-offtake clauses, and the generator is at that stage operating at or below the fixed offtake threshold, to such degree that a reduction in output would not result in a reduction in fuel cost, or an increase in output would not result in an increase in fuel cost;
- Combinations of above might also be appropriate, given that electricity demand reflects a differing hourly profile, combined with the fact that electricity production is mainly still a matter of instantaneous balancing of supply and demand. This could lead to the situation that the capacity which is needed and in equilibrium with demand during the peak demand period, would reflect a temporary (for a few hours) surplus during the off-peak or 'standard' demand periods. Thus on an hour-to-hour basis it might well be that the concept of LRMC would apply to most hours but in particular hours the concept of SRMC would be appropriate.

These concepts are however mainly used in management decision making. It is not known that this is used anywhere in the world as the basis for economic regulation of the revenue or the tariffs of regulated entities.

Whereas the consultation paper does not clarify which type of marginal cost is envisaged, the example provided during NERSA's presentation at the stakeholder workshop on 18 October 2021 used the SRMC. This would not be appropriate from a cost-recovery perspective thus also not in adherence to the requirements of the ERA and the EPP.

In addition it would not be appropriate as a type of 'market-related' proxy given that efficient markets by definition set the price at the LPMC of the system i.e. the LCOE of the next incremental capacity option.

Furthermore it should be recognised that the concept of 'marginal cost' will by definition always reflect a higher unit cost and price than the concept of average cost or total actual cost. In a regulated context this will then provide an 'over-recovery' or revenue compared to average cost or total actual cost.

Approach to 'generation pricing'

It is our understanding that NERSA's proposed approach to 'generation pricing' is motivated by the principles of efficient generation dispatch, and pricing energy on the basis of the incremental cost of power.

Starting with generation dispatch, we understand the approach as identifying the average unit cost of supply of each generating facility, and using that average unit cost for the purpose of merit order of dispatch. We further understand that this is meant to align with the proposed principle presented in S1.5.2 which posits that different "*demand profiles (which) ideally should be supplied with generation plants that have the same or similar supply profiles*" and that "*different generation units have their inherent different costs derived from the equipment design (a function of the purpose, the technology and related fuel, amongst other costs)*".

Eskom is not aware of this approach being applied elsewhere, and we do not see how it would improve on the Scheduling and Dispatch Rules (SDR) as approved by NERSA and currently applied by the System Operator in operation of the Interconnected Power System (IPS). Unfortunately, NERSA does not provide the type of comparative analysis that should form a

starting point for this review. While not a perfect substitute for such analysis, we are able to highlight important elements of the SDR that serves to illustrate reasons for our concern.

Having in mind that NERSA's proposed approach appears to be predicated on the use of station specific average unit cost in setting the merit order of dispatch, we offer a highly abridged summary of relevant dispatch rules as provided for under the SDR (using the rules for thermal generating plant as an example as found in Section 4.4 of the SDR, and paraphrased for the purpose of this discussion).

Dispatchable Thermal Generator Submissions (Section 4.4 of the SDR)

Under provisions of the current SDR, dispatchable thermal generators must provide a daily submission of the expected hourly availability of each generating unit and the incremental cost curve associated with the dispatch of those units. The information provided must include availability indicators in the form of:

- *hourly declared available capacity (in MW),*
- *whether the generating unit is flexible, or inflexible to central dispatch*
- *whether the generating unit is available to provide Instantaneous Reserve or not;*
- *whether the generating unit is available to provide Regulating Reserve or not*
- *whether the generating unit is available to provide 10 Minute Reserve or not*
- *The incremental cost of production in the form of a piecewise-linear cost curve.*

Where circumstances change generators must lodge adjusted incremental cost submissions and maintain records supporting that adjustment for a minimum period of five years.

The Dispatch Algorithm (Section 4.8 of the SDR)

Information provided in the Dispatch Submissions form a key input to the Dispatch Algorithm for the Unconstrained Schedule (S4.8) which determines the optimal dispatch for all qualifying generators and demand-side resources for each hour of the dispatch day, taking into consideration:

- *hourly expected demand,*

- *reserve requirements,*
- *non-dispatchable generator schedules and interconnection schedules, and*
- *the costs and availabilities of dispatchable generators and demand-side resource (not inclusive network constraints).*

The objective of the Unconstrained Schedule dispatch algorithm is to minimise the total cost of generation required to meet expected demand, constrained by the reserve requirements and technical capabilities of dispatchable generators.

The total cost of generation includes the incremental cost of generation for each scheduled generator, the start-up costs for generators synchronised during the period and the costs of dispatching demand-side resources. Regulating, instantaneous and 10 minute reserve is co-optimised with the energy dispatch schedule taking into account individual reserve requirements.

Once the Unconstrained Schedule is determined the SO incorporates transmission network constraints to determine the Constrained Schedule. The Constrained Schedule dispatch algorithm objective is to minimise the total cost of generation within the additional security constraints imposed by the SO to cater for transmission network and other constraints required to meet security of supply objectives.

Eskom views the SDR (in its entirety) as fit for purpose and aligned to international practices. We find no reason or evidence supporting NERSA's proposed revision of approach to generation dispatch (referred to as generation pricing as described in Sections 1.5 and 5.9 of the Consultation Paper).

Efficiency and reporting of costs (e) and (f)

- In regard to ensuring that only efficient generation costs are recovered we refer to NERSA's Guidelines for Prudency Assessment which was developed under a robust process of stakeholder consultation.
- In regard to the reporting of cost information we refer to the RRM Volumes 1 and 2 (including all issues highlighted to NERSA previously regarding these Volumes), and if gaps have been identified, that a review of that regulatory instrument be considered.

3.5 Transmission, System & Market Operation Costs

Stakeholder Question 5:

- a) *Is this information adequate to achieve activity-based costing regulation? If not, please provide an alternative.*
- b) *What would be an appropriate tariff cost build-up for a transmission business to make a return on its investment?*
- c) *Stakeholders are requested to comment on the appropriateness of the approach proposed by NERSA to set the transmission component of the price of electricity.*
- d) *Which international benchmarks and best practices should NERSA consider – both in terms of type and sources?*
- e) *How should NERSA ensure that only efficient costs from the transmission utilities are recovered?*
- f) *Is the list of costs identified by NERSA sufficient? If not, suggest the other relevant costs.*

Information requirements (a)

While we are unable to comment on the information needed to “*achieve activity-based costing regulation*” as we do not understand what ABC regulation might entail.

We do note that transmission costs are not driven by the volume of energy transmitted on the Grid but rather in terms of the capacity created and maintained to enable the safe and reliable operation of the system and its assets. Therefore, the format provided in Table 4 of the Consultation Paper is not viewed as fit for purpose.

Due to the integrated nature of the power system, transmission assets cannot be classified based on servicing base, mid-merit or peaking load (as shown in Figure 5). The flaws in this concept is that it is assumed that loads / generators are homogeneous and that a specific asset only serves a specific load as well as that there will always be a unidirectional flow of power. As the penetration of Distributed Generation grows, it will increasingly result in a bi-directional flow of power creating changing utilisation profiles on a daily basis based on renewable resource availability. The concept that assets can be dedicated to specific load categories would therefore be erroneous and inappropriate for the allocation of costs.

Transmission costs are not driven by the volume of energy transmitted on the Grid but rather in terms of the capacity created and maintained to enable a safe and reliable system operation

and electricity transport service. License conditions and Grid Code reliability criteria require that capacity be created for current and future customers.

There is therefore a reasonable correlation between the connection capacity (MVA) that needs to be serviced and the reliability at a connection point relative to the input cost drivers. The integrated transmission power system comprises of both line and substation assets and enables the provision of the required capacity and reliability. With respect to reliability, the system expansion investment criteria are defined in the Grid Code and are based on standard international practice for transmission system design. As the reliability provided by the integrated transmission system benefits all industry participants the costs for deep system strengthening needs to be allocated to all generators and loads.

The pricing methodology, as described in the Transmission Tariff Code of the South African Grid Code, is already based on a locational use of system pricing approach for network capacity and technical losses. The methodology should be upgraded to account for regional peak system flows, rather than on overall peak demand as a driver for transmission costs. Furthermore, the forward-looking and location based tariffs signals should be updated regularly to account for the gradually evolving generation pattern, with shifts between fuels, and new locations, and future battery connections which will increased demand flexibility.

Cost drivers related to the system and market operation activities cannot be allocated to individual assets without using an averaging approach as they are for the benefit for all system users. A future competitive market model where the market operator operates a trading platform for voluntary participation could allocate transaction costs to participants.

The ancillary services principles as outlined in clause 1.6 of the Consultation Paper regarding the fact that the provider of each service will apply for his/her own tariff, individually, by presenting costs associated with his/her own equipment is indeed a step in the right direction. The consultation paper assumes that the services are obtained from generators. It should be noted that the demand side also provides ancillary services and the implications thereof need to be fully understood.

Capacity charges for generators providing standby capacity will need to be recovered by means of a fixed cost / demand charge (it is understood that this is being addressed as part of the EPP amendment).

The objectives of the existing Transmission tariff methodology (as defined in the Grid Code) includes providing predictable prices to customers over time as well as pricing signals that reflect the cost structure of the services provided.

The South African Grid Code (Tariff Code) requires that the transmission tariff shall be divided into the following components to cover the respective cost categories:

- Network charge: The network charge is allocated based on the annual maximum demand (KVA) or installed capacity for load customers and generators.
- Connection charge: The connection charge is based on the cost of assets used for the benefit of a single customer.
- Reliability services charge: The reliability services charge is determined by energy usage and the cost of procuring ancillary services.
- Losses charge: The losses charge to both generators and load customers reflects the relative amount of losses associated with a specific position on the network for a generator or for a load.

There are potentially improvements that can be made to the existing Tariff Code to improve alignment with the anticipated future industry changes. Amongst other, this includes the allocation of costs in relation to energy losses as well as the treatment of costs allocations for ancillary services.

It is therefore recommended that the existing tariff methodology (as defined in the South African Transmission Tariff Code), largely be retained as basis but that it be reviewed and enhanced. A larger industry forum is required with inputs from all stakeholders as well as internationally recognised experts and practices to shape the revision of the methodology.

Cost build-up for a transmission business to make a return on its investment (b)

Speaking to the licensed activities carried out by Eskom Transmission, the costs to be recovered to make a reasonable return on investment include the following

- Remuneration of invested capital
- Depreciation
- Transmission costs

- Transmission operating and maintenance costs
 - Transmission technical losses
 - Asset management costs
 - System planning
 - Overheads
 - Research and development programmes/projects, etc.
- Market operator costs
 - System operator costs
 - Government imposed levies or taxes

Importantly, these costs should allow for prudent network expansion, stability and asset renewal.

We further refer Section 15(1) (b) of the ERA which speaks to incentives for the continual improvement of the technical efficiency in the services provided. On this matter we note that a Transmission Service Quality Incentive Scheme is explicitly provided for in the MYPD Methodology as part of the Allowed Revenue Formula which is aimed achieving just such outcomes.

Transmission network service providers are capital-intensive businesses. As per the Electricity Regulation Act (ERA), Transmission's tariffs must be based on recovering a revenue that would allow an efficient transmission entity to recover the full cost of its licensed activities, including a reasonable margin or return. Broadly speaking two types of network regulation exist internationally, namely rate-of-return regulation and incentive-based regulation.

By defining that the operating and capital expenses must be recovered plus a rate of return on investment, the ERA already defines that the methodology to be used should be that of a rate of return regulation. It however also allows for some form of incentive based regulation in that tariffs must provide for incentives for continued improvement of the technical and economic efficiency with which services are to be provided. NERSA has implemented the Service Quality Incentive (SQI) scheme in order to incentivise performance improvements.

In terms of capital expenditure, the main trade-off is between minimising network costs – e.g. investing just enough for meeting reliability standards in the future – and making additional investments for the purpose of facilitating competition and/or the sustainable development of the system. In order for the Transmission business to be able to fund such investments it would need to ensure there would be revenue certainty and a rate of return on such investments aligned with the weighted average cost of capital. Regulated service providers typically will only have interest to invest if the recognised return allows them to cover costs of equity and debt finance needed for the realization of the envisaged projects.

The increasing use of variable renewable energies (wind and PV generation) requires a review of the current transmission pricing methodology, as defined by the Transmission Tariff Code of the South African Grid Code. The current method is based on a nodal/zonal pricing methodology considering peak load conditions only. This methodology was developed considering a classical power system with large dispatch-able bulk generation feeding into the main transmission system and a dominant power flow direction.

However, the integration of variable renewable energies has changed the fundamentals on which the original pricing scheme was developed.

- Firstly, the fact that PV doesn't produce during evening peak hours, but still requires additional transmission lines shows that a new pricing scheme is required, which considers peak, off-peak and hours of high renewable generation.
- Secondly, the generation pattern is gradually evolving, with shifts between fuels, and new locations. New generation in export regions, particularly the Cape Coastal areas, contributes to increasing levels of network investments.

The transmission network pricing mechanism must be evolved to account for the fact that in a system with more intermittent generation, and smarter more flexible demand, different areas of the network face different cost drivers. Furthermore, periods of regional peak system flows, rather than overall peak demand, are better reflections of individual regional cost drivers and are more effective at signaling to the use the system.

In summary the following are principles for a tariff build up:

- A reasonable return is to be provided on the deployed asset base using the weighted average cost of capital in order to service debt interest costs as well as provide a shareholder return
- Depreciation in order to fund debt repayments
- Recovery of costs related to transmission operating expenditure, transmission energy losses, ancillary services, System Operator and Market Operator prudent expenditure

Transmission pricing (c) and (d)

As presented in the Consultation Paper, the proposed pricing methodology appears to utilise load factor as a cost driver which we assume to be incorporated in design of transmission charges pricing. This is not viewed as an appropriate cost driver for the transmission system in that it does not capture the need to provide system reliability, or the efficient level of network capacity needed to meet the real time needs of generation and loads. We have not observed this approach being applied in any jurisdictions we are aware of.

International practice – of which South Africa's Grid Code is aligned to - is premised on proportioning costs based on the maximum notified demand (KVA) of generators and loads.

We further note that a number of issues raised in the Consultation Paper pertaining to transmission pricing are addressed in the South African Grid Code (Tariff Code). For example, the Grid Code requires that the transmission tariff shall be divided into the following components to cover the respective cost categories:

- Network charge: The network charge is allocated based on the annual maximum demand (KVA) or installed capacity for load customers and generators.
- Connection charge: The connection charge is based on the cost of assets used for the benefit of a single customer.
- Reliability services charge: The reliability services charge is determined by energy usage and the cost of procuring ancillary services.
- Losses charge: The losses charge to both generators and load customers reflects the relative amount of losses associated with a specific position on the network for a generator or for a load.

As alluded to in the Consultation Paper, the preferred approach to recovering the cost of these elements will be dependent on the broader market and industry structure they relate to. Eskom recognises that the transmission network pricing mechanism must be evolved to account for the fact that in a system with more intermittent generation and smarter more flexible demand, different areas of the network will face different cost drivers. Furthermore, periods of regional peak system flows, rather than overall peak demand may better reflect individual regional cost drivers and prove to be more effective at signaling system usage.

While not intending to speculate on matters that fall outside of the scope of NERSA's mandate, we do recognise that there may be elements of the Code that could be improved without need to speculate on future market and industry structures. With this in mind, it would be preferable to focus on *well-defined elements* of the extended regulatory framework (such as elements of the Grid Code) rather than the broad brush taken in review of the pricing regime.

Efficient and prudent costs (e) and (f)

As for generation, we refer to NERSA's Guidelines for Prudency Assessment and the RRM.

In order to ensure that only efficient costs are recovered NERSA can perform the following activities:

- Grid Code compliance in terms of the required capital investment criteria
- Ensure asset maintenance practices conform to industry standards
- A review the costs contained in the licensee's revenue application

Costs that need to be recovered include:

- Fair return on assets in terms of the weighted average cost of capital should allow for network expansion, stability and asset renewal investments
- Depreciation
- Operating Expenditures
- Transmission Operating and Maintenance costs
- Asset Management costs
- System Planning
- Overheads
- Research and development programmes/projects, etc.

- Ancillary Services and Demand Response costs
- Transmission Technical Energy losses
- Government imposed levies or taxes

3.6 Distribution Equipment Costs

Stakeholder Question 6:

- a) Is this information adequate to achieve activity-based costing regulation? If not, please provide an alternative.*
- b) What would be an appropriate tariff cost build-up for a distribution business to make a return on its investment?*
- c) Stakeholders are requested to comment on the appropriateness of the approach proposed by NERSA to set the distribution component of the price of electricity.*
- d) Which international benchmarks and best practices should NERSA consider – both in terms of type and sources?*
- e) How should NERSA ensure that only efficient costs from the distribution utilities are recovered?*
- f) Is the list of costs identified by NERSA sufficient? If not, suggest the other relevant costs.*

Information requirements (a)

As for Generation and Transmission

Cost build-up for a distribution business to make a return on its investment (b)

Again, referring to Section 15(1)(a) of the ERA As per the Electricity Regulation Act (ERA), Distribution tariffs must allow an efficient distribution entity to recover the full cost of its licensed activities, including a reasonable margin or return.

By defining that the operating and capital expenses must be recovered plus a rate of return on investment the ERA implicitly points to rate of return regulation. However, provisions of the ERA also indicates the application of incentive based regulation in that tariffs must provide for incentives for continued improvement of the technical and economic efficiency with which services are to be provided.

Activity Based Costing requires a correlation between the input activity cost drivers and the outputs. There is no direct correlation between the Distribution system load factor and the input activity cost drivers, as the system needs to be available and reliable irrespective of loading conditions. The use of the load factor as the cost driver is therefore inappropriate.

Distribution costs are not driven by the volume of energy transmitted on the Grid but rather in terms of the capacity created and maintained to enable a safe and reliable network operation and electricity distribution service to both its customers and generators connected to the network. License conditions and Distribution Network Code criteria require that adequate and reliable capacity be created for current and future customers, and to take into account the requirements for the evacuation of the distributed generation on the Distribution networks.

There is therefore a reasonable correlation between the connection capacity (MVA) that needs to be serviced and the reliability at a connection point relative to the input cost drivers. Cost drivers related to the distribution system operation activities cannot be allocated to individual assets without using an averaging approach, as they are socialised for the benefit of all system users.

The integrated distribution power system comprises both line and substation assets and enables the provision of the required capacity and reliability to its customers. The Distribution Network Code defines that all shared network investments shall be constructed with the premise that the least economic life-cycle costing option is chosen (with a proviso that it is technically acceptable). As the shared network capability provided by the integrated distribution system benefits all customers, the costs for deep system strengthening thus need to be socialised across all connected generators and loads.

The existing Distribution Tariff Code indicates that tariffs should recover current regulated revenue requirement, but may reflect future cost drivers in their structure to provide clear pricing signals to the customer, that may also promote economic efficiency.

The South African Distribution Tariff Code requires that for tariff design purposes, the ring fenced electricity revenue requirement of a Distributor shall typically be segmented into the following categories as per an accepted cost allocation methodology such as NRS 058.

It is therefore recommended that the existing tariff methodology, as defined in the South African Distribution Tariff Code, largely be retained as basis given that it largely meets the objectives of this review.

A review to enhance the Tariff Code could include focus on the following issues:

- Cost allocation of losses between generators and loads
- Loss calculation methodology
- Network charges based on use of access
- Reliability service charges and structure (move to a fixed and variable component and a revaluation of the costs)
- Network Stability and flexibility requirements
- Differentiation between customer categories to include generation and load considerations

In addressing the situation as it currently stands with bundled costs the following apply:

- Purchase costs
 - Energy
 - Transmission use of system charges
 - Distribution share of Market Operator costs
 - Distribution share of System Operator costs
 - Distribution share of Ancillary Services costs
- Distribution costs
 - Remuneration on invested capital
 - Depreciation of regulatory assets
 - Distribution operating and maintenance costs
 - Asset management costs
 - Central and Admin
 - Distribution technical and non-technical energy losses

- Government imposed levies or taxes
- Retail
 - Retail operating costs

Distribution network service providers are capital-intensive businesses. As per the Electricity Regulation Act (ERA), the Distribution tariffs must be based on recovering a revenue that would allow an efficient distribution entity to recover the full cost of its licensed activities, including a reasonable margin or return.

By defining that the operating and capital expenses must be recovered plus a rate of return on investment the ERA already defines that the methodology to be used should be that of a rate of return regulation. It however also allows for some form of incentive based regulation in that tariffs must provide for incentives for continued improvement of the technical and economic efficiency with which services are to be provided.

In terms of capital expenditure, the main trade-off is between minimising network costs – e.g. investing just enough for meeting reliability standards in the future – and making additional investments for the purpose of facilitating competition and/or the sustainable development of the system. In order for the Distribution business to be able to fund such investments it would need to ensure there would be revenue certainty and a rate of return on such investments aligned with the weighted average cost of capital.

Distribution pricing (c) and (d)

Distribution costs are not driven by the volume of energy transmitted on the Grid but rather in terms of the capacity created and maintained to enable a safe and reliable network operation and electricity distribution service to both its customers and generators connected to the network. License conditions and Distribution Network Code criteria require that adequate and reliable capacity be created for current and future customers, and to take into account the requirements for the evacuation of the distributed generation on the Distribution networks.

There is a reasonable correlation between the connection capacity (MVA) that needs to be serviced and the reliability at a connection point relative to the input cost drivers. Cost drivers related to the distribution system operation activities cannot be allocated to individual assets without using an averaging approach, as they are socialised for the benefit of all system users.

The integrated distribution power system comprises both line and substation assets and enables the provision of the required capacity and reliability to its customers. The Distribution Network Code defines that all shared network investments shall be constructed with the premise that the least economic life-cycle costing option is chosen (with a proviso that it is technically acceptable). As the shared network capability provided by the integrated distribution system benefits all customers, the costs for deep system strengthening are socialised across all connected generators and loads.

A review to enhance the Tariff Code could include focus on the following issues:

- Cost allocation of losses between generators and loads
- Loss calculation methodology
- Network charges based on use of access
- Reliability service charges and structure (move to a fixed and variable component and a revaluation of the costs)
- Network Stability and flexibility requirements
- Differentiation between customer categories to include generation and load considerations

Distribution pricing (e)

In order to ensure that only efficient costs are recovered NERSA can perform the following activities:

- Distribution Network Code compliance in terms of the required capital investment criteria
- Ensure asset maintenance practices conform to industry standards
- A review the costs contained in the licensee's revenue application

Distribution pricing (f)

The list of costs that must be recovered by a Distribution Service Provider and Distribution System Operator include the following:

- Fair return on assets in terms of the weighted average cost of capital should allow for network expansion, stability and asset renewal investments
- Depreciation

- Operating Expenditures
 - Operating and Maintenance costs
 - Asset Management costs
 - Network Planning
 - Overheads, including data management and administration
 - Research and development programmes/projects
- Ancillary Services and Demand Response costs
- Distribution Technical Energy losses
- Government imposed levies or taxes

3.7 Trading Costs

Stakeholder Question 7:

- a) *What are the cost elements at the trading level of electricity value chain?*
- b) *The pricing approach intends to separate out the 'wires' business of electricity supply (transmission/distribution) from the 'transactions' business of trading – is this realistic in the current market? Please substantiate your answer.*
- c) *How should the NERSA ensure that the costs at trading level are efficiently recovered?*

Cost elements, unbundling and recovery of trading costs (a) (b) and (c)

- The cost elements of trading are dependent on the universe of options at hand pertaining to the establishment and scope of mooted unbundled market operations, and the nature of the market itself.
- To suggest that the “, pricing approach intends to separate out the 'wires' business of electricity supply (transmission/distribution) from the 'transactions' business of trading” seems to presume that NERSA is mandated to make policy prescriptions on matters of industry and market structure.
- Likewise, the premise in which NERSA is to “ensure that the costs at trading level are efficiently recovered” presumes a specific model of ownership and governance, and the scope and role of the trading function. Trading is Eskom is currently an activity licensed to Distribution and this cost is recovered through the tariffs. If the pure activities related

to this trading function was separated out, this would have a tariff charge that would be so small as to be meaningless

These are all important issues to address but are outside of the scope of this review.

3.8 Retailing Costs

Stakeholder Question 8:

- a) *Comment of the costs list required from retail business*
- b) *How could the price of retail business be best set?*

Retail costs (a)

Retail costs currently are bundled into Eskom's Distribution licensed activities. Abstracting from energy purchases – costs to be recovered in the retail business consist of:

- IT costs
- Call centers
- Customer service and administration costs associated with billing, meters, meter reading and customer service.
- A retail margin on sales

Method for setting retail prices (b)

To comment on the manner in which retail prices are best set requires definition of the market and industry structure that the retail activity is to be provided. In jurisdictions where there is a robust competitive market at the level of retail sales there may be no need to set prices.

Alternatively, where retail competition is not deemed to be effective one observes various approaches to regulation focusing on non-competitive segments of the supply chain. One also observes examples of price oversight where there is little or no direct intervention.

3.9 Type of Service Costing – Differentiated Load Profiles

Stakeholder question 9:

Stakeholders are invited to comment on whether:

- a) the proposed approach addresses the concern raised about the current pricing approach detailed in sections 4 and 5 above;
- b) the proposed model achieves efficient economic allocation of resources used to supply electricity.
- c) the proposed approach will encourage efficient investment into the sector; and whether the model caters for the unbundled electricity sector with an ISO.

3.10 Time of Use Pricing

Stakeholder Question 10

Stakeholders are requested to comment on:

- a) whether TOU rates encourage economic allocation of resources and accurate investment decisions from both the demand side and supply side;
- b) the reasonableness of charging TOU prices for baseload consumption, particularly during peak energy demand periods; and
- c) pricing approaches that will lead to proper allocation of costs to customers based on the resources that are used to generate electricity to serve the type of demand – reflecting the cost to serve, regardless of when they need it.

Load based costing and TOU pricing (questions 9 and 10)

The observations provided in Section 6.4 of the Consultation paper are not contentious – but we are unsure how the proposed approach referred to in question 9 is to be distilled from that section.

For example, if the proposed approach alluded to in question 9 relates to system marginal pricing as found in some wholesale power markets observed globally – then we understand how that might apply to wholesale energy costs and pricing, and there are a myriad of issues to examine if that is the case. Indeed, given merit order based dispatch rules applied currently Eskom's generation costs as aggregated over time may not be entirely different from that which would have been obtained under the system marginal price mooted in this discussion

(although the ever growing level of 'must run' or self-dispatch IPP supply distorts this feature of merit order dispatch).

However, we would need further discussion of what is entailed in regard to transmission, system operator, distribution and sales as shown in Table 5. In this regard reference to the source of that material would be helpful.

We further presume that questions 9 and 10 are closely related, but again request further explanation of exactly what is being proposed. But based on our limited understanding of the material presented in sections 6 and 7 of the Consultation Paper – it does cover significant ground and warrants further consultation and clarification. Nevertheless, we do have some initial comments:

- a) We gather that the proposed approach would impact on various types of users in a systematic manner. The relative price impact should need to be explicitly modeled, understood and reported as part of the consultation process.
- b) Baseload consumption add to the peaks just as intermittent consumption does at peak times. It is irrational to attribute generation cost causality to one type of customer or another. Allocation of energy cost, is totally irrelevant to the type of use, but rather to the when the energy is used. All customer's even base-load customer use electricity in peak time and to assume that only base-load generation costs should be allocated to high load factor base-load customers is discriminatory, nonsensical and illogical. This would imply that all other customer pay for the variability and large industrial customer get allocated the "best" process generation. This also ignores the fact that renewables are part of the generation mix and more expensive energy pay actually be produced in the peak time.
- c) It is not possible to trace the use of a particular generation plant to the use by particular customer. It cannot be as simplistic allocating one to one by using accounting terms, this is not the way a power system works.
- d) Contrary to the anecdotal observations offered; studies do show that customers do respond to tariff signals and such evidence has previously been provided to NERSA
- e) In the absence of real time pricing or markets, the use of TOU tariffs are a well-established tariff design principle
- f) If the argument is that the wholesale price should not be TOU based, this would encourage customers that are responding to the signal to consume more in peak periods, and this

would have a serious impact on managing the system and increase costs, impacting all customers. This impact would have to be addressed,

- g) What seem to be missing in the discussion with "type-of-use" is that this energy is not purchased directly by a customer from generation sources.
- h) This proposal to go to type-of-use would have a serious negative impact on all non-energy intensive users and will remove the price signal contained in the time-of-use tariff that even these large industrial customers currently respond to.
- i) The allocation of costs is not based on what the customer uses electricity for, but in the way the electricity is used, that is, type of use is already inherent in the way customers use electricity.

Time of Use structure

- a) The current tariff TOU structure provides pricing signals in the absence of a market, and that these signals need to be enhanced.
- b) Removing the TOU signal removes the incentive to manage demand in peak resulting in increased cost, may result in gaming, introduces a revenue risk and removes the customer's ability to save if they do respond.
- c) The introduction of TOU tariffs for residential customers is a must and Eskom submitted to NERSA in 2020 a proposal to do so.

3.11 Indexing for Year-On-Year Price/Tariff Increases

Stakeholder Question 11:

- a) *Stakeholders are requested to comment on the appropriateness of using indexing as a method on increasing approved prices.*
- b) *What is the appropriate method of indexing electricity/increasing approved prices?*
- c) *Which other indicators can be used to index electricity prices, other than inflation?*

Appropriateness of using indexing as a method for pricing (a)

Indexing as a method for increasing allowed revenue and prices is sometimes employed in the regulation of mature network businesses where input costs are largely fixed and there is little need for capacity augmentation or replacement.

In such cases costs are likely to track broad measures of inflation such as the producer price index or consumer price index. That said, one still needs to determine a base level in which to apply the index, and consider the circumstances under which that base would be re-set over time.

For activities such as generation where fuel costs vary with production and sales volumes, and where unit costs of fuel are subject to market volatility the index approach will serve to drive a wedge between allowed revenue and efficient costs of supply – contrary to provisions of the ERA and EPP.

The growing level of IPPs of which costs flow through Eskom is a further impediment to use of an index approach, with the cumulative impact of a growing base of IPPs increasing aggregate costs at a far greater pace than indexes such as the PPI or CPI would suggest. .

Even in relatively mature network businesses having a cost base that is largely fixed a number of factors need to be considered in the application of the index approach that allow for step changes in costs driven by lumpy investment profiles in capacity augmentation projects.

Appropriate method of indexing and indexes other than CPI (b) and (c)

Eskom does not support any method of indexing as applied to the determination of allowed revenue or pricing.

4. PROPOSED WAY FORWARD

i) Determination of Efficient costs and a fair return (Revenue requirement)

The responses provided by Eskom in this consultation paper have clearly clarified that a need exists for the determination of a revenue requirement. This concept can also be referred to as establishing the efficient costs and a fair return. It has also been established that the sales forecast, as determined by NERSA, will also need to be considered. This is a common approach used by many regulators across the world. It is thus recommended in this response that the prevailing MYPD methodology that has been applied for many years be used as the basis for any further review as far as determining efficient costs and a fair return are concerned. It is accepted that there is always room for improvement. Eskom has acknowledged this, and has already provided proposals for the review of the prevailing MYPD methodology (as published in 2016) for NERSA consideration. This was submitted to NERSA during May 2020. It is proposed that this submission be considered in NERSA undertaking a review of this aspect of its regulatory mandate. Eskom is not providing any proposals on the treatment of other utilities, such as municipalities in this regard.

ii) Separation of costs from tariffs

This response has provided clear indication of the separation of costs from tariffs. It has been illustrated that these are two very different concepts and cannot be merged and used as proxies. This again is a world-wide phenomenon and has been utilised by regulators of the electricity industry. In addition, all efficient costs would need to be considered. Assumptions cannot be made on particular generating technologies supplying particular customers.

iii) Application of required sequential processes

It is submitted that many of the ideas and concepts that this consultation wishes to implement are wrongly placed. This results in impossible requirements for the whole industry. It is proposed that the existing framework, appropriately applied could provide the envisaged outcomes. Eskom has provide clear guidance on the existing processes that can easily be utilised to allow for further progress. The sequential process which is already applied is the;

- First, the determination of the efficient costs and a fair return
- Second, determination of the cost to serve

- Thirdly, tariff design

It needs to be cautioned that each of these three steps are complex and require various considerations, especially in accordance with already existing policy, legislation and regulatory rules and codes.

The present policy, legislative, regulatory framework is what needs to be worked within the policy, legislation and regulatory framework related to the electricity industry has evolved over many years. It is acknowledged that further work needs to be done in this arena. It has been pointed out that this consultation paper seems to have not sufficiently considered the significant amount of progress already made. These policies, legislation and regulatory framework has involved all stakeholders in its development. The application of these existing frameworks will definitely go a long way in legitimately allowing the implementation of certain concepts and ideas espoused in this consultation paper. The details of each of these frameworks have been discussed in the Eskom responses. It is cautioned that policy and legislative requirements cannot be violated.

iv) Decision-making is where challenges are faced, not methodologies

Eskom humbly submits that further significant progress can easily be made if timeous decisions are made after due process is followed. NERSA already has powerful frameworks in place that could be applied to address many relevant and viable concepts that are alluded to in the consultation paper. It again needs to be cautioned that all decisions have impacts that need to be considered. A big bang approach is not supported. An incremental approach is proposed. This also implies that timeous decision making is required. It goes without saying that due processes need to be followed. It is submitted that NERSA, within the existing framework, can implement significant changes in tariff structures, once due process is followed. This would also require impacts to be ascertained prior to even making proposals. For argument sake, it may not be appropriate to make proposals that result in over 30% increase in residential tariffs.

v) Eskom has reviewed NERSA's rejection decision of MYPD 5 application

A court process has been initiated to allow for NERSA to make a revenue decision effective from 1 April 2022.

vi) Eskom has submitted a proposal for restructuring of Eskom retail tariffs

Eskom last revised its tariff structures in 2012 based on a cost-of-supply (or cost-to-serve/CTS) study. Since then, technology has developed at a fast pace, customer needs have changed and continue to change, and the tariff charges no longer accurately reflect the Eskom cost splits for energy, networks, and retail. The further unbundling of tariffs to accurately reflect current cost to avoid volume and trading risk and to reflect cost drivers more accurately. Eskom has made a submission to NERSA during August 2020. This application has undergone a stakeholder consultation process. All that remains is for NERSA to make a decision on the submission made. There is merit in ensuring that this submission be urgently addressed as this would update tariffs to reflect the disaggregated cost. This submission allowed for incremental changes. In addition, tariff changes are within the realm of NERSA and Eskom can only make changes once due process has been followed. Eskom is already in the process of developing further proposals in an incremental manner for NERSA consideration.