12 August 2022

ANNEXURE A

JOINT EIUG-MCSA SUBMISSION: METHODOLOGY FOR THE DETERMINATION OF TARIFFS AND PRICES IN THE ELECTRICITY INDUSTRY

Overarching comments

The current draft methodology was preceded by a draft version published in September 2021. Whilst some enhancements have been made, it cannot be considered an improved methodology compared to the Multi-Year Price Determination (MYPD) methodology, primarily because it lacks detailed formulae and rules for interpretation. There is for instance no approach regarding forecasting or cost overruns and how these critical shortcomings of the current methodology will be remedied. There is also no indication on how the principles will affect actual tariffs.

Hence it is fair to state that the concerns regarding the existing MYPD methodology and the implementation thereof by National Energy Regulator of South Africa (NERSA), also referred to as Energy Regulator) are not sufficiently addressed by the draft methodology and the proposed changes to the methodology. In particular, the main concern of large users, namely predictability and certainty of prices, is not addressed. It is in fact made worse by the proposal to have quarterly or even monthly price adjustments. Regrettably, there is no effort to identify the actual shortcomings of the MYPD and to address these in a systematic manner. In our view, NERSA should instead undertake a thorough review of the MYPD methodology, and its implementation, to diagnose its shortcomings in order to remedy the MYPD methodology. Only where it is not possible to remedy the MYPD methodology to achieve the objectives of the regulator should a new methodology be developed. If that is the case, in the short to medium-term the MYPD methodology and the implementation can be improved whilst the new methodology is being developed.

The methodology is largely focussed on enabling price determination in an unbundled South African electricity supply industry (ESI). Specifically, it details how prices/tariffs are to be determined in each of the different levels of the supply chain – generation, transmission, system operations, market operations, distribution and trading. It also deals with the data and information requirements for setting tariffs at these different levels.

It is surprising that NERSA does not refer to its own Gazetted Regulatory Reporting Manuals 2008 (RRMs), which provide a clear framework for the dis-aggregation of costs and accounting principles that regulated entities in the electricity sector should adhere to. We are of the view that Eskom and other licensees should be required to implement these cost accounting guidelines as soon as possible. This is much preferred to the development of new data gathering tools. We refer to our earlier statement on the need for a new methodology, which in our view should be preceded by a review of the MYPD methodology and its implementation, before a new methodology is developed. Once this has been done, NERSA is expected to conduct a consultative process on the new methodology which should provide appropriate time for stakeholders to formulate their inputs. In our view, on such a fundamental matter, NERSA should ideally give stakeholders 2-3 months to respond, so that stakeholders can undertake a thorough analysis and provide what we hope will be valuable inputs to the Energy Regulator for its consideration.

The three principles identified in the draft methodology are:

1. Disaggregated electricity costs and prices/tariffs;
2. Cost-reflective tariffs/prices;
3. Consumer prices based on consumer load profiles.

The key emphasis of the draft methodology centres on the idea that the electricity tariffs/prices should be cost-reflective. This will be determined by gaining a thorough understanding of the demand characteristics and load profiles of the various customer categories. Such an approach requires significant data gathering not only by Eskom but by municipalities as well. However, the methodology fails to address the key challenges of the determination of electricity prices/tariffs in South Africa as well as how the proposed new methodology will impact on these issues/challenges. We further believe that any new methodology should be future-proof and therefore the development of a new methodology before the Electricity Regulation Act Amendment Bill (2022) (ERA Amendment Bill) and the revised Electricity Pricing Policy (2022) (EPP) are finalised is futile and premature. There are many unresolved issues regarding the market design in these policy and legislative documents and therefore, any methodology that precedes the finalisation of these principles is highly likely to be outdated and incompatible with the regulatory framework as soon as the ERA Amendment Bill and the EPP are finalised. This does not mean we believe NERSA should not improve the MYPD methodology at present. We encourage NERSA to develop and implement incremental improvements to the MYPD methodology as soon as possible and provide several suggestions in this regard in the comments below.

Points of agreement

The EIUG and MCSA have identified the following (general) points of agreement with the draft Electricity Price Determination Methodology (EPDM):

1. The view that the ESI must be unbundled, and the associated costs dis-aggregated into component activities is strongly supported. We note that NERSA put in place the framework for such disaggregation by Gazetting the RRMs in 2008. We encourage NERSA to enforce the implementation of the RRMs and would have wished that Eskom had been required to implement these principles and apply for the various regulated activities based on the disaggregated costs during the last 14 years. There is nothing stopping NERSA from implementing the RRMs.

2. In addition, whilst MYPD4 only provides for the split among Generation activities ("Gx"), Transmission activities ("Tx") and Distribution activities ("Dx"), the EPDM provides for a more detailed split within the electricity value chain. The EPD Methodogy proposes a much more detailed split where:
   - Gx is split per power station;
   - Tx is split among System Operations, Marketing Operations and Central Purchasing Operations; and
   - Dx is split between Distribution Wires and Distribution Trading.

3. Although the Regulatory Reporting Manual ("RRM") Volume 2 does not provide for the above detailed split, the chart of accounts can be adjusted to accommodate this level of reporting. The methods used to record and recognise RAB, WACC and operating expenses are consistent with those contained in the RRM Volume 1 and 2. No contradictions were observed.

4. The EPDM proposes the use of ABC method to allocate costs among various activities identified in the value chain. Although this approach is already provided for in the RRMs, to separate regulated and non-regulated activities, an adjustment may need to be made to provide for the development of Cost Allocation Manuals (“CAMs) to allocate costs within regulated activities. In addition, some of the direct costs identified will need to be treated as shared or indirect costs when allocating them to the different activities within the value chain.

5. Cost-reflective pricing can also be supported in principle. Particularly the EIUG and MCSA support absolute transparency in the cross-subsidy framework and a gradual move towards greater cost-reflectiveness over time.

   However, the EIUG and MCSA will have concerns regarding the sweeping manner in which cost-reflectiveness is addressed in the draft methodology. We propose that NERSA undertakes a rigorous assessment of the Eskom-level cross-subsidies, as well as the municipal cross-subsidies. With respect to the cross-subsidies in Eskom’s price structure we strongly encourage NERSA to limit these cross-subsidies at the present level and to implement a process of incremental reduction of these cross-subsidies over time. At the same time, NERSA can engage with national government to advocate for direct subsidies (fiscal transfers) to be implemented in those cases where the government identifies a need.

6. Principle 2 recognises that electricity customers’ demand profiles are different, which impacts on the type of loads and corresponding electricity generation plants need to be dispatched and when. This principle is a statement of fact and therefore agreed with. This is essentially how the merit order works in practice at present. However, we have come across statements that ‘baseload customers do not contribute to the peak’ and should therefore pay baseload prices only. We note that in electricity industries in general, all users that consume during peak periods are charged prices reflecting the higher demand and that only in the context in which a Day Ahead or short-term market coexists with a well-developed Over the Counter (OTC) market for bilateral agreements between generators and consumers, the referred to unitary baseload price could be arrived at for all periods of usage.

When a market setting price is available however, the incentive for any producer is to participate in a day-ahead market for peak demand in order to charge peak prices. We therefore anticipate that should the market be introduced without the development of long-term bilateral agreements in anticipation of said market, Eskom will simply bid all its generation production into the Day Ahead market to realise peak prices for every kilowatt hour (kWh) dispatched during peak periods. The consultation paper does not provide sufficient detail to ascertain whether safeguards will be put in place to prevent such price spikes from occurring.

7. We also agree that stronger price signals can be conveyed via the price structure of electricity, particularly Time of Use prices. We support greater differentiation in the Time of Use tariffs to give consumers a clear signal regarding the costs of their particular demand pattern.

   This is the appropriate place for marginal cost analysis in the ESI and we encourage NERSA to develop the principle of more prominent price signals stated in the draft EPDM in greater detail so it can be implemented.[1] NERSA should however indicate to what extent it would like to see the price signals change in the next 5-10 years as a sudden change in the price structure is likely to be met with much resistance and cause regulatory uncertainty that can discourage investment and employment creation.

8. NERSA's differentiation between the concepts of 'tariffs' and 'prices' is supported. Redefining these important concepts requires amendment of the Electricity Regulation Act. We encourage NERSA to ensure these basic concepts are correctly incorporated in the ERA Amendment Bill. We also note that whilst in the definitions of 'price' and 'tariff' respectively, the correct distinction is made between tariffs and prices, the definition of the methodology refers to 'tariff setting methodology' despite the latter clearly including prices for electricity as well as tariffs for services. The methodology further refers to the Weighted Average Tariff, which is defined as the proportion of power dispatched at the related 'tariff,' which should be amended to refer 'prices' or 'prices plus tariffs.'

[1] Note that we disagree with the notion that marginal costs can be utilised for price setting per se. Marginal cost analysis is appropriately used in price setting in developing a price structure with correct price signals, not for determining actual or average prices.

It is important for the definitions to align to the ERA and the ERA Amendment Bill. It is not appropriate for the Energy Regulator to redefine concepts that are defined in legislation, unless these changes will also be made in the legislation by amendment. In our understanding the current version of the ERA Amendment Bill no longer contains a definition for 'price' and the definition of 'tariff' includes any charge for a licensed activity other than a surcharge, tax, levy or duty imposed by a municipality. We agree with NERSA's definition and encourage NERSA to ensure these basic concepts are correctly incorporated in the ERA Amendment Bill.

9. The shortcomings of the implementation of the MYPD methodology to provide price certainty are also acknowledged. We are of the view however that the MYPD methodology and implementation should be reviewed before a new methodology is developed, if at all. It is possible to undertake price/tariff restructuring to achieve greater cost reflectiveness and correct price signals even without a new methodology. In our detailed comments we will address this issue in greater detail, the essence of which is summarised below.

   We must point out that the ability to set efficient prices depends as much on reliable forecasts as any other methodology and NERSA's failure to factor the reality of Eskom's declining sales into its price determination is a considerable contributor to the unpredictable price path. After more than 17 years of price determination experience by NERSA the stakeholders expect NERSA to be able to manage the regulatory game that Eskom appears to engage in, by over-forecasting demand and under-forecasting costs, resulting in high but manageable increases, that are increased by the weak enforcement of efficiency rules that result in exorbitant ex-ante Regulatory Clearing Account (RC)A balances. The RCA approach is a well-established and internationally accepted approach to dealing with minor forecasting errors in regulated price settings. Rather than doing away with the mechanism, NERSA should improve its efficacy.

   In particular, the experience of the last 10 years or so has shown that price escalations are driven by the following factors inter alia:

   - Primary energy costs, particularly diesel costs to run Open-cycle gas turbines (OCGTs), but also coal costs;

- Demand forecasting errors (in particular, overestimation of future demand in the context of off-grid flight);
- Capital cost overruns; and
- Exogenous shocks, such as the Covid19 lockdowns.

NERSA is effectively able to curb the first three of these drivers. To deal with coal costs, NERSA can provide incentives for Eskom to manage its coal contracting better, for instance by allowing a higher margin for a year if efficiencies are extracted, as the decline in long-term coal contracts has been a major contributing factor to the coal price escalations. As coal prices are determined on international markets, there are coal price indicators and industry experts that NERSA should utilise to ensure it provides an achievable and realistic coal price pass-through.

Cost overruns for coal usage that arise from inferior coal quality, higher than design specification coal burn or inefficient coal purchasing should be disallowed. Similarly other primary energy cost overruns, particularly for running OCGTs in excess of the allowable load factor, should be disallowed. Where the OCGTs are running excessively due to Eskom's declining electricity availability factor (EAF), Eskom should be given clear incentives for improving the EAF, and conversely, 'penalties' (disallowed cost recovery) for a worsening EAF. Given the cost to the economy of loadshedding we believe that OCGTs should be deployed when the reserve margin becomes unmanageable, but these costs should be recovered from the shareholder as the responsible party for a failing company, not rate payers.

Given the current institutional arrangements, it is understood that disallowed costs simply move the burden from the rate payers to the taxpayers, as the shareholder is the South African Government, and that this is far from ideal, but this is simply where the responsibility for cost overruns and operational inefficiencies rests. It is more appropriate for the fiscus to keep a State-Owned Company (SOC) afloat, than it is for rate payers, as the tax system is a progressive one and electricity price increases tend to be regressive in nature on companies and households alike.

To deal with demand forecasting errors, NERSA should at the time of price determinations perform rigorous assessments of the trends in demand, and should err on the side of under- rather than over-forecasting. This would yield a more predictable price path and end the practice of price increases being masked by over-forecasting of demand at the time of price determination, followed by retroactive RCA applications. In order to manage capital costs, NERSA can consider fixing the capital expenditure at the time of construction, based on international benchmarks and the Electric Power Research Institute (EPRI) report for instance, and not allowing endless cost overruns and construction delays to be passed to the customers. We note that NERSA currently has that power and has to date chosen not to disallow the majority of cost overruns. This is despite clear indications that in the construction of Medupi and Kusile in particular, Eskom failed to manage the construction process; did not engage an engineering, procurement and construction (EPC) contractor to mitigate the construction risk; and was unable to ensure quality control of the equipment purchased and installed. The cost overruns and construction delays did not qualify as the costs of an ‘efficient’ licensee and should therefore have been disallowed.

10. Regarding municipal prices and tariffs, we strongly support the Energy Regulator in requiring Cost of Supply studies and determining the municipal unbundled prices based on efficient costs. The current practice of ‘benchmarking’ municipal prices and tariffs is in fact an averaging exercise with little actual benchmarking analysis. We are not aware of a systematic Data Envelopment Analysis or other cost driver identification and quantification exercise that takes account of objective differences in the cost structure of certain municipalities to arrive at scientifically ascertained and benchmarked costs. The current position that municipalities must submit Cost of Supply studies to support their price and tariff applications has not been effectively enforced by NERSA. We therefore encourage NERSA to implement its mandate by setting prices and tariffs for each municipality based on Cost of Supply studies.

    We note that such an exercise does not require a complete overhaul of the MYPD methodology as NERSA has the mandate to set prices for all licensees and has included the Distribution Grid Code and other requirements in the licence conditions for municipalities. This means that the principles enshrined in the NRS 058 (Cost of Supply Methodology) can be enforced at present.

Other comments and responses to the discussion paper

After these introductory remarks and points of agreement, we have categorised our other comments by theme as outlined below:

1. Unbundling and cost dis-aggregation
2. Cost-reflectiveness and cross-subsidies
3. Introduction of the multi-market
4. Price vs revenue regulation
5. Predictability of prices
6. Data requirements and capacity constraints
7. Consistency with the Gazetted ERA Amendment Bill, 2022 and draft Electricity Pricing Policy as revised, 2022
8. Municipal prices
9. Timeframes
10. WACC calculation

1. Unbundling and cost dis-aggregation

1.1 The principle of cost disaggregation according to activities is required for the regulation of the soon to be unbundled ESI. This principle was already established by NERSA in 2008, with the development of the RRMs as Gazetted. RRM volume 1 deals with general regulatory reporting procedures and administrative matters and RRM volume 2 deals with electricity specific reporting. The table of contents of Volume 1 indicates that activity-based costing has for the past 14 years been a requirement of reporting by Eskom and other licensees.

1.2 Chapter 3 of the RRM Volume 1 indicates the cost allocation and separation principles and Chapter 4 the cost allocation and separation methodology that each licensee is required to follow. It is further clear from the preamble of the RRM Volume 2: Electricity (quoted below) that the RRMs are aimed at prescribing the precise format, content and preparation of information to the Energy Regulator to enable the Regulator to perform its functions.

"Purpose: To prescribe and provide guidance to the regulated entities in the Electricity Supply Industry on the format, content, preparation and submission to the Energy Regulator of required information to perform its functions."

1.3 The question therefore arises why NERSA is redefining cost allocation (or 'activity-based costing') whilst making no reference to the existing guidelines on cost separation in the draft EPDM. The suggestion that data collection templates need to be developed (slide 38 of the presentation provided by NERSA at the workshop of 22 July 2022) and that data will be collected once every five years, despite the semi-annual and annual requirement in the RRMs (item 7.1 and 7.2 of Volume 1, p16), is also highly curious in this context.

1.4 Hence, whilst the EIUG and MCSA support the principles of unbundling and cost-disaggregation, we urge NERSA to implement and enforce the framework already in place without delay, rather than to overhaul the entire regulatory framework.

1.5 In addition, whilst MYPD4 only provides for the split among Generation activities, Transmission activities and Distribution activities, the EPDM provides for a more detailed split within the electricity value chain. The Methodology proposes a much more detailed split where:

- Generation is split per power station;
- Transmission is split among System Operations, Marketing Operations and Central Purchasing Operations; and
- Distribution is split between Distribution Wires and Distribution Trading.

1.6 Although the Regulatory Reporting Manual ("RRM") Volume 2 does not provide for the above detailed split, the chart of accounts can be adjusted to accommodate this level of reporting.

1.7 The methods used to record and recognise RAB, WACC and operating expenses are consistent with those contained in the RRM Volume 1 and 2. No contradictions were observed.

2. Cost-reflectiveness and cross-subsidies

2.1 The key principle unpinning the draft methodology is the need for electricity tariffs and prices to be cost-reflective. However, the methodology fails to address the issue of the necessity for subsidies and/or cross-subsidies. It is acknowledged that cost-reflective tariffs will firstly require explicit and transparent (cross-) subsidies. The methodology proposes that the funding for the subsidies should come from the Government budget and not cross-subsidies. (par. 7.3.5) It is stated *"… in the case of households, if a need for a subsidy has been identified based on the underlying cost-reflective price, the assessment and payments could actually be provided via the Social Welfare services. Unless clearly justified this subsidy will not be paid by other electricity users but would be paid through the budget of the appropriate ministry."* (par. 7.3.5)

2.2 The value of the subsidy is based on the difference between the 'cost-reflective' price and the 'proven' competitive/affordable price (par. 8.4.12.6). The competitive/affordable price will be determined by benchmarking electricity prices against regional and international prices (par. 7.3.2). *"Where the affordable/competitive price is less than the cost reflective price, then the government has an accurate basis upon which to subsidise different sectors, or not."* (par. 7.3.2)

2.3 We agree with the principle of replacing cross-subsidies (that are a regressive tax on large electricity users in the case of Eskom-level cross-subsidies) with direct subsidies, there are several challenges to this approach. The South African Government's budget is significantly constrained which means it will be difficult to fund the subsidies for electricity consumers in the short term.

2.4 Clearly there is a need for cross-subsidies to be quantified, explicit and based on a clear rationale, so that a needs analysis can be done, the current levels can be capped and a phasing out approach can be developed. According to research undertaken on behalf of NEDLAC in 2018,[2] the large industrial users (mainly on the Megaflex tariff) provide the cross-subsidies (as contained in Eskom's tariff structure) and essentially pay an additional

[2] Teljeur, E., Rateiwa, R., Bukula, T., and Sheik, F., "Review of Eskom's Business Model – A report for NEDLAC." 9 November 2018, pg.86 and 90.

amount for their electricity. This cumulative amount is substantial, as it exceeded R12 billion in 2017/18. (It must be noted that this excludes the municipal level cross-subsidies, the extent of which is currently unknown).

2.5 We are concerned that NERSA has not published any research analysing the current cross-subsidies to quantify the impact on electricity prices to reach cost-reflectiveness. It is expected that reasonable efforts are undertaken to perform impact analyses of significant regulatory decisions. We therefore encourage the Energy Regulator to quantify the current level of cross-subsidisation.

2.6 We also support absolute transparency in the cross-subsidy framework and a move towards cost-reflectiveness over time. We also support greater differentiation in the Time of Use tariffs to give consumers a clear signal regarding the costs of their particular demand pattern.

2.7 It is important to note that the current wholesale cross-subsidies are contained in the electricity retail tariff system (ERTS) for which Eskom applies effectively every year/ MYPD period. In our view then, a complete review of the price setting methodology as proposed is not necessary to undertake the tariff restructuring to achieve greater cost reflectiveness as NERSA can tackle the cross-subsidies via incremental changes in the ERTS. It is important for NERSA to take steps to make the cross-subsidies explicit and transparent so that the process of price restructuring can commence. We recommend that NERSA implements the RRMs for Eskom's different functions and transitions the municipal applications to this approach too.

2.8 The methodology makes accommodation for 'subsidies' in two instances. The first is in respect of municipalities where various surcharges are included in municipal tariffs. The revenue raised from the surcharges is used to subsidise the provision of other municipal services. The methodology states that such surcharges will be regarded as a pass-through. *"Municipal surcharges imposed in terms of the Constitution and Municipal Systems Act, 2000 (Act No. 32 of 2000), will be treated like taxes, hence they will be a pass through. Currently the surcharges are simply part of the Municipal tariff, but not ring-fenced and transparently itemised."* (par. 8.4.9.1) The ring-fencing and transparency objective of the draft EPDM are supported.

2.9 Second, cross-subsidies are also mentioned in respect of existing and 'legacy' Independent Power Producers (IPPs) Power Purchasing Agreements (PPAs), where the price of the electricity generated by these IPPs is significantly higher than the current Eskom average tariffs and the recent IPP bid prices. The draft EPDM indicates that the guarantees in the PPAs require that compensation must be paid. The proposed solution to this is for the IPPs to be compensated through a levy that is paid by all electricity users. "*such contracted IPPs would need to be compensated through a levy that is paid for by all electricity users.*" (par. 8.4.12.1) (see also slide 53 and 54). This appears to be a concept borrowed from the ERA Amendment Bill and revised draft EPP, although in our understanding the legacy contracts would include most of the current generation agreements, including Eskom's supply to the Single Buyer.

2.10 Further, the suggestion that the 'competitive/affordable' electricity price/tariff should be determined by benchmarking South Africa's electricity prices/tariffs against regional and international tariffs and prices is also highly problematic. The methodology does not provide details on the approach and methodology to be applied in comparing the prices and tariffs. It is widely acknowledged that depending on the approach adopted an international price comparison exercise can provide very different results. Eskom's price comparisons have shown that South Africa's average electricity tariffs are low compared to other countries. Whereas other comparisons show a less positive picture. In addition, the assumption that other countries electricity prices/tariffs are determined in 'competitive' markets is also problematic. Generally, the approach in the draft methodology to the very critical issue of (cross-)subsidies and their treatment is not adequately addressed.

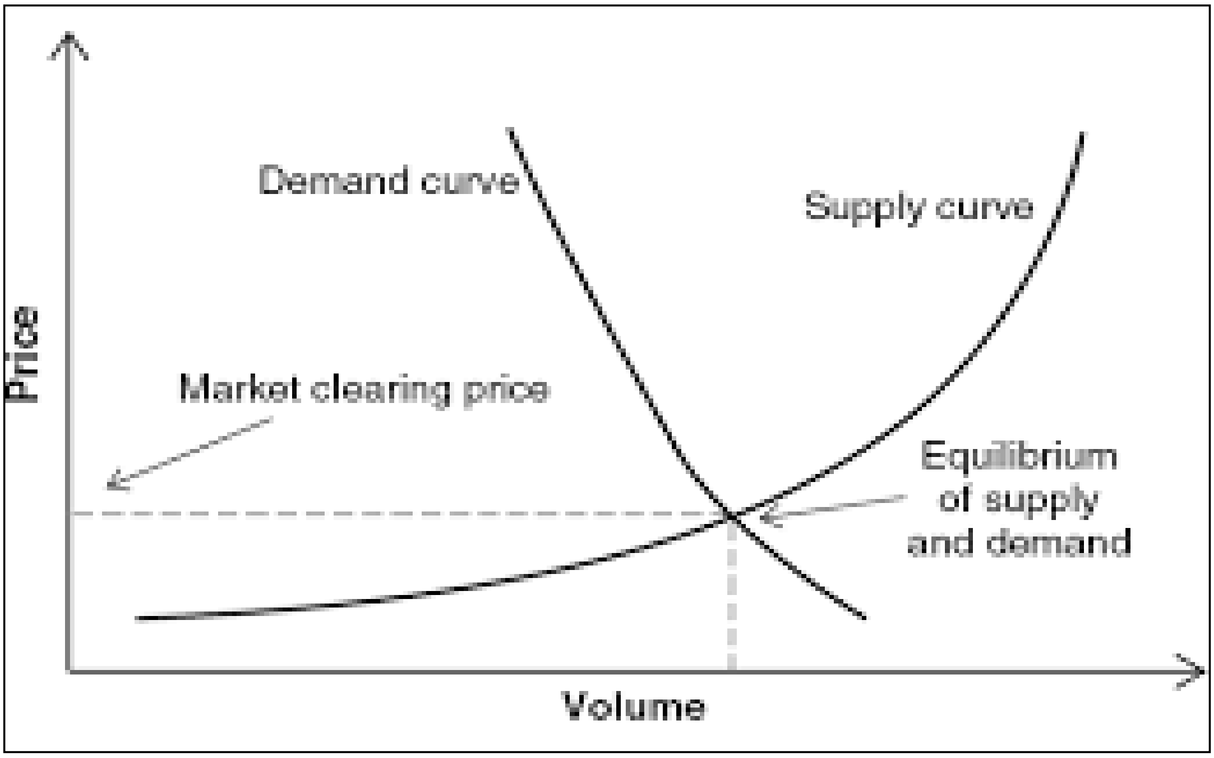
2.11 In summary, the view of the EIUG and MCSA is that the cross-subsidies in all levels of the value chain should be capped at the present level, and that the cross-subsidies in Eskom's price structure should be reduced or phased out over time. This requires a concerted effort by NERSA to quantify these cross-subsidies first, preferably using the RRMs. Where a need for subsidies is identified by government, we support the view that such subsidies are dealt with as fiscal transfers (direct subsidies) that can be targeted, means-tested and where applicable time-limited. With respect to the cross-subsidies at the municipal level, we urge NERSA to engage with policy makers to develop alternative local government funding mechanisms so that the price distortions that are present in municipal tariffs can also be phased out. In this case, NERSA should also enforce the RRMs and ensure that municipalities perform Cost of Supply studies lest penalties for violation of licence conditions be imposed.

3. Introduction of the multi-market

3.1 Given the tight reserve margin and other factors, we are of the view that a fully liberalised market is not feasible in the short to medium term. Should the market be rapidly liberalised, and all electricity be traded on the Day Ahead market (and complementary market platforms), the country will suffer from price spikes the likes of which it has not seen to date. This is not only because, in a tight supply situation, generators can strategically withhold supply to drive up prices as has been the case in several electricity markets around the world (the California effect), but also because of the mechanics of market-clearing prices in a relatively price inelastic setting. To be clear, we are not arguing that all electricity demand in SA is price inelastic, as this is certainly not the case for large users who are competing in international commodity markets. However the overall demand is sufficiently price-inelastic, especially in a newly set-up market, to result in extreme price spikes.

3.2 In a market setting, supply is offered incrementally as prices rise and demand is reduced incrementally as prices rise. As a result, the point where demand and supply meet sets the price for the accepted supply and demand bids, including those supply bids at lower prices and those demand bids at higher prices. When this happens in an underdeveloped market in which long-term bilateral contracts are for instance not well-entrenched to supply base-load capacity, this means that each unit of electricity traded will fetch the last price bid.

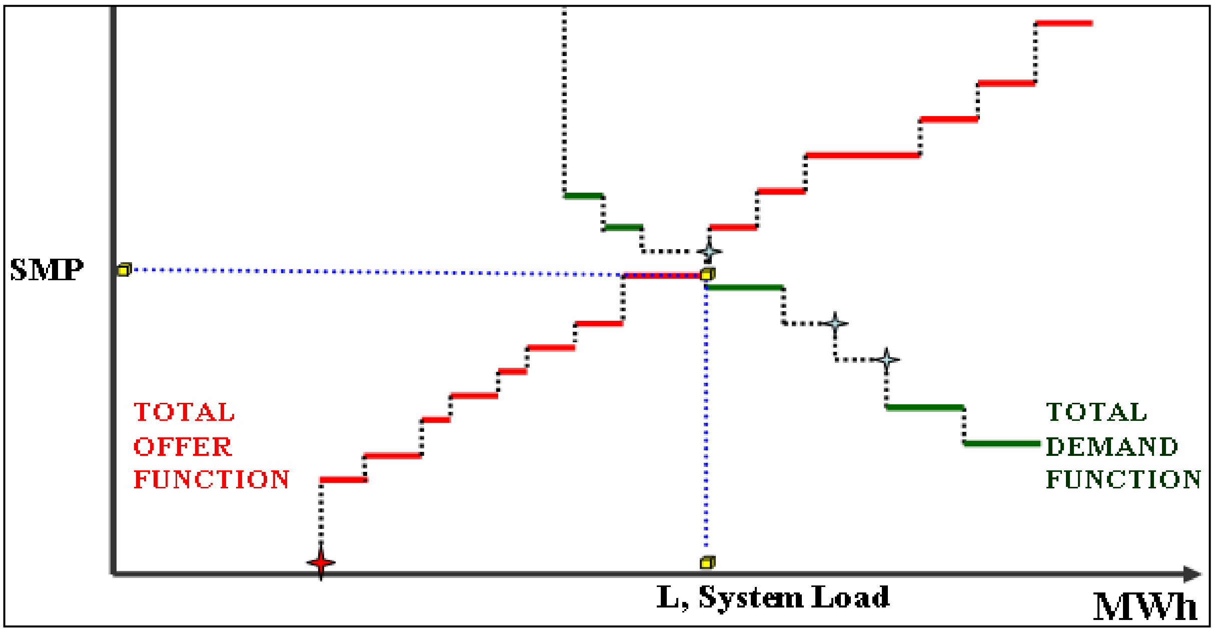
Figure 1: *Demand and supply curves*



Source: https://www.oreilly.com/library/view/managing-energy-risk/9780470029626/10_chapter004.html

3.3 In the above graphic a simple representation of market clearing prices is shown. The area under the demand curve and above the market clearing price is the consumer surplus (consumers that were willing to pay more than the market clearing price) and the area above the supply curve and below the market clearing price is the producer surplus (representing producers that were willing to accept lower prices than the market clearing price). In an emerging electricity market the curves will look more like the graphic below as electricity is offered in blocks of uniform price, where SMP stands for system market price.

Figure 2: Market-clearing process



Source: https://www.researchgate.net/figure/Market-clearing-process_fig1_27381180

3.4 These graphics are provided to demonstrate what would happen if baseload capacity and peak capacity were all traded in a Day-Ahead market. In a particular hour of the day, the outcome would not be a price based on a percentage baseload prices and another percentage peak prices, but every kWh traded for that hour would fetch the peak price. This is a fundamental departure from how electricity prices are arrived at using the current merit order approach.

3.5 This is why we do not believe that the intention of the policy makers it to move the entire supply of the South African ESI to a market platform, without the necessary OTC or bilateral market being developed first. The bilateral market is hampered by the historically low blended electricity prices in South Africa, which makes it unlikely that a new IPP of any generation technology other than certain renewables could easily find sufficient off-take supply to render the project bankable. Customers simply will not pay new baseload coal or gas-fired generation prices for 100% of its supply when the alternative is the blended supply provided by Eskom. Even when the generation capacity is horizontally unbundled, it would mean that consumers would benefit from the largely amortised coal-fired generation capacity as this supply would continue to be blended with more expensive new coal generation capacity and peak and mid-merit technologies.

3.6 We believe therefore that the envisaged end-state of the South African ESI as emanating from the relevant policy department, the Department of Mineral Resources and Energy (DMRE), will be one in which the majority proportion of the generation capacity will remain regulated and will be purchased by the Central Purchasing Agency, the successor of the Singly Buyer. Over time, market based bilateral contracts will replace much of the current purchases from the Single Buyer, as customers and suppliers enter into long, medium- and short-term supply contracts with a migration to new generation costs. Even as this happens over a period of at least 10 years, many smaller and residential customers will continue to enjoy regulated supply, as the current level of cross-subsidisation will need a long time to be replaced by subsidies and other arrangements.

3.7 As many of the details of the multi-market platform as envisaged by government have not been worked out yet, we believe it is premature for NERSA to develop a new methodology for electricity prices and tariffs. We also point to the risks of a market in a supply-constrained electricity industry and urge NERSA to develop market governance capacity and to engage with policy makers to ensure the market principles are carefully designed and appropriate for the current ESI in South Africa.

4. Prices vs revenues

4.1 The legal basis for NERSA to determine the methodology for regulating electricity prices is well understood. However, we point to the mandate provided to NERSA in the ERA and question whether each facet of this mandate has been implemented to the same extent. For instance, sections (15)(1)(b)-(e) indicate that electricity prices must do more than just allow an efficient operator to recover its costs including a return: Tariffs

"15 (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."

4.2 Regarding section 15(1)(b):

4.2.1 In our experience as large users, we see few incentives placed before Eskom to continually improve its technical and economic efficiency. The very weak provisions of the MYPD methodology provide for a Transmission incentive based on lost system minutes, whilst not providing any incentives for improved generation performance, which is where clearly the current challenges are being experienced. If anything, in terms of the current MYPD methodology, should Eskom be able to produce, transmit and distribute electricity more efficiently than expected, the SOC will be expected to give the savings back to the consumer (the other side of the RCA coin) so that there is literally no incentive to produce, transmit or distribute electricity more efficiently. We propose that this situation is remedied soonest by the introduction of meaningful efficiency incentives.

4.2.2 There are also no penalties for the extreme drop in the EAF of many of Eskom's generation plants. Hence it is our view that the MYPD can be significantly improved by implementing real incentives for technical and economic efficiency (a profit-sharing arrangement or higher WACC for instance) and by placing higher demands on the test for efficiency and prudency.

4.3 Regarding section 15(1)(c):

4.3.1 It is clear that Time of Use differentiation can be enhanced to give customers a clearer incentive to reduce their load during peak times where possible. This is however not done by means of the methodology to determine the average price or the allowable revenue determination. Instead this is done by revising the overall tariff structure, for which no change in the MYPD is required as it is done via the ERTS Applications (ERTSA). At present it seems that Eskom is on a very slow trajectory towards greater cost-reflectiveness and price signals and that NERSA is not very pro-active in this respect.

4.3.2 We agree that stronger price signals can be conveyed via the price structure of electricity. This is the appropriate place for marginal cost analysis in the ESI and we encourage NERSA to develop the principle stated in the draft EPDM in greater detail so it can be implemented. NERSA should however indicate to what extent it would like to see the price signals change as a sudden change in the price structure is likely to be met with much resistance. See also our views on cost-reflectivity in the relevant section of this letter.

4.4 Regarding sections 15(1)(c) and (d)

4.4.1 Despite clear requirements in the EPP to the contrary, cross-subsidies remain largely implicit and therefore hidden. A first step in identifying cross-subsidies as inappropriately large, would be to quantify the cross-subsidies. Eskom has been very secretive in this regard and organised Business has had to fund research via NEDLAC to uncover the approximate extent of the cross-subsidies. This is unacceptable. NERSA should provide transparency in the price build-up of the various customer categories so that as a first step the cross-subsidies become apparent and quantifiable.

4.4.2 Thereafter a process of assessment should be followed in which the cross-subsidy levels are benchmarked internationally and the impact of the cross-subsidies on the various customer categories is assessed. If subsidisation of certain users is required or preferred, this should be done from the fiscus as the tax system in South Africa is of a progressive nature. Cross-subsidisation tends to lead to less-targeted, loosely quantified and at times regressive outcomes (in which certain categories of electricity users pay a disproportionate share of the cross-subsidies, regardless of income). We want to emphasise the impact that cross-subsidies have on the ability of the productive and exporting sectors to compete in the global marketplace. This must be taken into account.

4.4.3 The recommendation to replace cross-subsidies with direct subsidies may face challenges given the fiscal constraints in the country. Whilst we understand that fiscal transfers are not NERSA's prerogative, the Energy Regulator should be the centre of excellence and knowledge on the energy sectors, and the impact of cross-subsidies therefore warrants the Regulator's time and effort to quantify.

4.5 We are also of the view that NERSA should place more emphasis on prudency and efficient cost reviews. S15(1)(a) prescribes that tariffs *'must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return.'* The ERA therefore provides NERSA with an opportunity to disallows certain costs if these are deemed inefficient. Nevertheless, this does not solve the problem that if the licensee is a SOC and costs are disallowed, these costs will then be covered by taxpayers and not the private shareholders of the utility as would be case in other examples. NERSA has recognised in the MYPD methodology that costs must also be prudently incurred (costs must not only be at efficient levels, which means that the level of production must be achieved with the least amount of costs possible), there must also be efficiency in procurement.

4.6 We submit that NERSA has done very little to establish efficient costs or to test the prudency of the expenditure by Eskom in particular. The EPP clearly indicates that prices must be cost-reflective, yet in every RCA reconciliation NERSA appears unable to disallow costs incurred by Eskom. When OCGTs are run at mid-merit and not peaking levels, even if this is to prevent outages, there should be consequences for the utility. We are of the opinion that no private generator would be able to pass-through the costs of its own inefficiency to the Single Buyer or consumers, and therefore believe that NERSA should rather apply the current methodology with greater precision and refine (or develop) the rules within the rate of return methodology that would allow NERSA to disallow costs when those costs are inefficient. Clearly, large users, like most users, would prefer there to be no loadshedding and are prepared to pay higher prices to prevent such outages. This should however not be a foregone conclusion and Eskom and its shareholder should be made aware that cost overruns cannot be passed through to customers without questioning or penalties.

4.7 Lastly, there is no guarantee that a move to regulating prices, rather than revenues will solve any of the problems associated with the MYPD methodology. If prices instead of revenues are regulated, presumably to eradicate the RCA issues, there will simply be wildly inaccurate forecasts as before, but this time without a clawback provision. As a result we anticipate that Eskom will overestimate costs and underestimate demand so as to arrive at the highest price possible, seeing that it is no longer subject to revenue regulation. This outcome may be worse than what is being experienced under the current MYPD methodology. We also note that the Ugandan electricity price methodology, on which some of NERSA's EPDM is based, is a revenue requirement methodology, that is, a rate of return based price setting method.

4.8 In this context, we also raise the misuse of the term 'marginal cost' in the methodology. The current version of the methodology indicates that the Weighted Average Tariff is the suggested proxy for a marginal price in the absence of a functioning/competitive market. Marginal costs do indeed have a place in rate design, where they are used to design price or tariff structures, not actual or average levels. There is a wealth of literature on this subject that indicates that marginal cost calculations are by no means straightforward. NERSA appears to have confused this use of the marginal cost concept in rate design with the notional or textbook outcome of a 'perfectly competitive market' in which prices in theory will gravitate towards marginal cost. Such a perfectly competitive market has stringent requirements and does not really exist in real life, save for certain specific commodities and settings.

4.9 Marginal costs do not typically cover average costs, but are lower than the costs based on the recovery of fixed and variable costs and a profit margin, and are therefore ill-suited for any rate of return regulatory setting, which in South Africa is required by the Electricity Regulation Act. Marginal cost pricing is also unlikely to emerge in South Africa's imminent Day Ahead market. In a competitive market, such as the one proposed by the ERA Amendment Bill, the price that will prevail at the Day Ahead market for each hour of the next day will in fact be the 'market clearing price.' Whether this price approximates the actual marginal cost of the marginal supplier in the market depends on many factors and cannot be taken for granted. A similar problem has arisen in the development of and subsequent court-mandated changes to the Methodology to approve Maximum Prices for Gas as adopted by NERSA. In the latter case misunderstanding of the marginal price concept by the legal fraternity has led to many counterproductive developments in the gas pricing methodology. We urge NERSA to avoid this thorny issue by correcting its use of 'marginal cost' concepts and referring to market-clearing prices instead where appropriate.

4.10 With reference to the notion that rate of return regulation, or the regulation of revenues can be abandoned (paragraph 1.4 and onwards) we submit that whilst the outcomes of the MYPD have not been predictable, neither the ERA nor the ERA Amendment Bill steer the ESI away from guaranteed returns or revenues, for an *efficient* licensee. Section 15(1)(a) of the ERA and of the ERA Amendment Bill both emphasise that an efficient licensee must be able to recover the full cost of the licensed activity and must allow for a reasonable return (commensurate with the risk of the licensed activity). This in essence prescribes rate of return regulation. In such a system, revenues are in fact guaranteed, contrary to NERSA's statements in this regard, as the returns must be allowed for the regulated prices in addition to full cost recovery. Whilst this may not be NERSA's preferred approach, there is no alternative unless the Bill is fundamentally changed. As long as Eskom plays the dominant role in generation as it does at present, NERSA would violate its mandate of ensuring a sustainable electricity industry by abandoning the principle of rate of return regulation, including the claw back / give back for under-recovered /over-recovered revenues.

4.11 The main difference between the MYPD4 and EPDM is that; whereas MYPD4 allows for an RCA clawback, MYPDM only allows for a reopener of the approved tariffs based on exogenous factors such as sharp increases in international fuel prices, exchange rates, etc as these are elements outside of the Utility's control. We do not believe that Rate of Return regulation allows for returns that are not in essence guaranteed and therefore we do not agree with the removal of the RCA elements as indicated.

4.12 Clearly the current state of flux is a difficult predicament for the regulator, similar to NERSA's challenge in regulating both Sasol's gas, imported by pipeline from Mozambique with a myriad of government commitments and concessions, and liquified natural gas (LNG) imported by entities that compete on international LNG markets. The two settings call for two different approaches, one regulated and one market-based. There is no reason why the electricity industry cannot have two bespoke approaches, one for the regulated transactions, including legacy PPAs, transmission and distribution tariffs, and one for the competitive market. We sympathise with the challenges the ERA and the ERA Amendment Bill pose for NERSA in this regard, as the ERA Amendment Bill has not provided the clarity required for the market or the regulatory framework. We therefore believe that NERSA should separate the two price regulating mechanisms, allowing the market to set prices on the Day Ahead market and in 'direct supply agreements' (or bilateral agreements) and focusing its price regulatory efforts on the regulated transactions which will include electricity sales to captive customers by the incumbent, transmission tariffs, and distribution tariffs. This is our understanding of how the transition to an electricity market will unfold.

4.13 Note that the DMRE and the Department of Public Enterprises (DPE) have not confirmed whether the envisaged end state of the ESI is one in which electricity prices will entirely be arrived at by the envisaged Day Ahead and bilateral agreement markets, or if a significant portion of the supply is meant to remain regulated, leaving considerable uncertainty for stakeholders. In this context then it seems premature for NERSA to radically overhaul the methodology, when this may only need to be done again once policy certainty is provided. Our preference is for the regulator to implement cumulative improvements to the MYPD methodology, dealing with the highly urgent issues of establishing a methodology to test the efficiency of Eskom's costs, signalling to the shareholder of Eskom that inefficient cost overruns will have to be recovered from the fiscus, and providing a more predictable price path. It is within NERSA's powers to provide regulatory certainty on the RCA and solving many of the problems associated with Eskom's problematic track record on cost and demand projections, without removing the rate of return principles altogether as is proposed in the methodology.

4.14 We are sceptical about NERSA's view that it can simply move from revenue regulation to price regulation as international experience has shown that price regulation, including price cap regulation, essentially boils down to a similar exercise of determining efficient costs and revenues and then devising a scientific approach to the X-factor. Just like in revenue regulation, price regulation requires rigorous demand and cost forecasting. To implement what NERSA has suggested in the methodology and confirmed in the workshop with the EIUG, MCSA, and other industry associations on 26 July 2022, namely that NERSA will set the price, and revenues, cost overruns and decreases in demand are Eskom's problem, is contrary to the ERA, the ERA Amendment Bill and goes against the interests of the long-term sustainability of the ESI on which the energy-intensive users depend for reliable supply. In our view such an approach is incompatible with the ERA and ERA Amendment Bill and is likely to be challenged resulting in longer delays in providing predictable prices.

4.15 We must point out that the ability to set efficient prices depends as much on reliable forecasts as any other methodology and NERSA's failure to factor the reality of Eskom's declining sales into its price determination is a considerable contributor to the unpredictable price path. After more than 17 years of price determination experience by NERSA the stakeholders expect NERSA to be able to manage the regulatory game that

Eskom appears to engage in, by over-forecasting demand and under-forecasting costs, resulting in high but manageable increases, that are increased by the weak enforcement of efficiency rules that result in exorbitant ex-ante RCA balances. The RCA approach is a well-established and internationally accepted approach to dealing with minor forecasting errors in regulated price settings. Rather than doing away with the mechanism, NERSA should improve its efficacy.

4.16 In particular, the experience of the last 10 years or so has shown that price escalations are driven by the following factors inter alia

- Primary energy costs, particularly diesel costs to run OCGTs, but also coal costs;
- Demand forecasting errors (in particular, overestimation of future demand in the context of off-grid flight);
- Capital cost overruns; and
- Exogenous shocks, such as the Covid19 lockdowns.

4.17 NERSA is able to curb the first three of these drivers. To deal with coal costs, NERSA can provide incentives for Eskom to manage its coal contracting better, for instance by allowing a higher margin for a year if efficiencies are extracted, as the decline in long-term coal contracts has been a major contributing factor to the coal price escalations. As coal prices are determined on international markets, there are coal price indicators and industry experts that NERSA should utilise to ensure it provides an achievable and realistic coal price pass-through. Cost overruns for coal usage that arise from inferior coal quality, higher than design specification coal burn or inefficient coal purchasing should be disallowed. Similarly other primary energy cost overruns, particularly for running OCGTs in excess of the allowable load factor, should be disallowed. Where the OCGTs are running excessively due to Eskom's declining EAF, Eskom should be given clear incentives for improving the EAF, and conversely, 'penalties' (disallowed cost recovery) for a worsening EAF. Given the cost to the economy of loadshedding we believe that OCGTs should be deployed when the reserve margin becomes unmanageable, but these costs should be recovered from the shareholder, not rate payers.

4.18 Given the current institutional arrangements, it is understood that disallowed costs simply move the burden from the rate payers to the taxpayers, as the shareholder is the South African Government, and that this is far from ideal, but this is simply where the responsibility for cost overruns and operational inefficiencies rests. It is more appropriate for the fiscus to keep a SOC afloat, than it is for rate payers, as the tax system is a progressive one and electricity price increases tend to be regressive in nature on companies and households alike.

4.19 To deal with demand forecasting errors, NERSA should at the time of price determinations perform rigorous assessments of the trends in demand and should err on the side of under- rather than over-forecasting. This would yield a more predictable price path and end the practice of price increases being masked by over-forecasting of demand at the time of price determination, followed by retroactive RCA applications.

4.20 In order to manage capital costs, NERSA can consider fixing the capital expenditure at the time of construction, based on international benchmarks and the EPRI report for instance, and not allowing endless cost overruns and construction delays to be passed to the customers. We note that NERSA currently has that power and has to date chosen not to disallow cost overruns, despite clear indications that in the construction of Medupi and Kusile in particular, Eskom failed to manage the construction process, did not engage an EPC contractor to mitigate the construction risk and was unable to ensure quality control of the equipment purchased. The cost overruns and construction delays did not qualify as the costs of an 'efficient' licensee and should therefore have been disallowed.

4.21 It is also important that the asymmetric treatment of Eskom compared to other generators is recognised and address. Every IPP is only paid once electricity is sold, whereas by contrast Eskom is provided with funds to undertake construction and its debt service obligations are safeguarded in each price determination. All indications are that not only is construction of generation capacity by Eskom more expensive and unlikely to be finished on time or on budget, as Medupi and Kusile indicate, but the capacity built is prone to faults and frequent breakdowns, imposing significant costs on consumers and industrial users. Hence, we would support changes to the MYPD methodology that treats all market players fairly and equitably.

5. Predictability of prices

5.1 The draft methodology indicates that prices will be set as follows:

- all prudent costs must be recovered;
- generators will be dispatched on a merit order basis;
- generation costs in the consumer prices will be determined on a Weighted Average Cost basis for each load type to achieve a Weighted Average Load Tariff; and
- prices will be 'regularly assessed' which would be monthly or quarterly (in arrears).

5.2 The new aspects of this process are in the determination of a Weighted Average Load Tariff and the more frequent price adjustments. Whilst the determination of a Weighted Average Load Tariff is not opposed, it is difficult to see how this would work in practice as it suggests (although details are lacking) that there will be no Time of Use variation of the Weighted Average Load Tariff. This would reduce the cost-reflectiveness of prices and distort the price signal, not improve it. A weighted average load tariff would calculate for instance that residential customers should pay for their peaky demand via a higher average tariff. If so, there would be no incentive for such consumers to reduce their load during peak times. We request NERSA to provide further details on how the Weighted Average Load Tariff would be arrived at.

5.3 One of the key concerns for large energy users has been the lack of predictability and certainty of electricity tariff increases. There is no long-term price path that large users can use to inform decision making and the significant year on year increases coupled with additional increases due to RCA applications further complicate decision making. The proposed methodology does not deal with this issue directly. However, the proposed changes to the methodology suggest that prices (at least at the wholesale level) must be reviewed quarterly and may be adjusted quarterly. Consumer prices may not be adjusted quarterly at least in the first year but can be adjusted quarterly in the following year.

5.4 *"The proposal is for the price to be reviewed every quarter using the information obtained in the preceding quarter – i.e. Prices will be assessed and possibly adjusted quarterly, in arrears. In the first year, the review of the price will not necessarily mean the consumer prices will be adjusted quarterly. The quarterly dispatched data may be used only in the following year to make adjustments if there have been any under recoveries or over recoveries. Quarterly price determination method may then be adopted in the second year of application."* (par. 8.4.12.3)

5.5 As large users we have to stress that quarterly price adjustments do not contribute to more predictable prices and that from a large user perspective, this is a worse outcome, not a better one. We therefore encourage NERSA to enhance the MYPD methodology so that it would allow NERSA to communicate a medium- to long-term price path prediction.

6. Data requirements and capacity constraints

6.1 Another key pillar to the draft methodology is the need to collect significant volumes of data to undertake the analysis to determine the 'cost-reflective' tariffs. There is no or very little consideration of the ability of municipalities to implement this framework for the determination of 'cost-reflective' tariffs. The larger municipalities such as City of Joburg, City of Cape Town and eThekwini may have the resources to undertake the analysis and work required to implement this methodology. However, the vast majority of municipalities would not necessarily have such capacity.

6.2 NERSA also relies on the significant roll-out of smart meters to enable the demand/load profile data required to determine the 'cost-reflective' tariffs. It seems irresponsible for the methodology to be based on data from smart meters where there is currently no plan or earmarked funding for the significant roll-out of these meters. Further, even if smart meters are rolled out only a small proportion of the population or service providers will be able to pay for such a meter. The methodology suggests that for those household customers that cannot afford smart meters, their consumption will be based on load profile of households that have smart meters. It is important to note that wealthy households that can afford smart meters are likely to have a different load profile to poorer households.

7. Consistency with the Gazetted ERA Amendment Bill, 2022 and draft Electricity Pricing Policy as revised, 2022

7.1 It is important to view the new methodology in the context of the existing Electricity Pricing Policy (2009) as well as the draft review thereof (2021), and the Electricity Regulation Act Amendment Bill (and in future the Amendment Act). As the ERA Amendment Bill has undergone and is currently undergoing major revisions, it appears to be inopportune to implement sweeping changes to the electricity pricing methodology at present. It would be better to refine the MYPD to address its shortcomings and to only overhaul the entire methodology once there is clarity on the legislative changes.

8. Municipal prices

8.1 The view that municipal electricity prices should be determined by NERSA based on a cost of supply study and unbundled costs is strongly supported by the EIUG and MCSA. However, it must be noted that this should be the case, even without a new methodology. The current approach of approving municipal 'tariffs' (i.e. prices and tariffs) by NERSA based on an averaging exercise of the various bundled municipal prices is highly inadequate. In our understanding however, there are several challenges to the unbundled cost-reflective approach as proposed by NERSA as municipal finance legislation allows municipalities to charge levies and surcharges on top of the electricity price and many municipalities have defied NERSA requirements for Cost of Supply studies in the last decade or so.

8.2 To introduce a radically different (and inevitably more complex) approach to municipalities when NERSA has been unable to extract straightforward Cost of Supply studies from many municipalities seems doomed to fail. Hence it would make sense for NERSA to enforce its current requirements before embarking on a more ambitious approach. We would strongly support the Energy Regulator in requiring Cost of Supply studies and determining the municipal unbundled prices based on efficient costs. Given the dearth of capacity in many municipalities it seems unlikely that NERSA will be able to determine cost-reflective and efficient prices and tariffs for each municipality in the next two years. Therefore our position is that we support NERSA in setting prices and tariffs for each municipality based on Cost of Supply studies as soon as possible.

9. Timeframes

9.1 It is clear that NERSA has set itself a target of a rapid overhaul of the electricity price setting methodology to be finalised by 30 September 2022. In light of the state of flux that the ESI is currently in, with ongoing amendements to the ERA and EPP, we believe this is unwise. The methodology is not implementation-ready, as many details are yet to be defined. We reject the notion that stakeholders should accept a methodology based on principles without having any information as to the outcomes of the proposed system. Even when certain principles are acceptable, much depends on the detail. NERSA has for instance made many references to cost-reflective pricing whilst at the same time indicating that cross-subsidies will be continued, albeit ideally funded as a direct subsidy from the fiscus or relevant government departments. There is simply too much room between complete cost-reflectivity and the current level of cross-subsidies for stakeholders to blindly trust that if the principles are correct, the outcomes will be such that the electricity production, transmission and distribution will both be sustainable and affordable. NERSA acknowledged that the current methodology is at a conceptual level during the workshop of 26 July 2022 where NERSA indicated it would get consultants to write or finalise the methodology.

9.2 We would advise NERSA that a better approach would be to improve the MYPD methodology and to implement this until the end-state of the ESI, the institutional arrangements, and the regulatory framework have been clarified. In particular, this means that NERSA should hold off on defining and implementing sweeping changes until the ERA Amendment Bill has been ratified and the review of the EPP has been finalised. In this process we believe NERSA has an active role to play, by advising government on the possible market structures and regulatory tools that would yield the best results.

10. WACC calculation

10.1 The EPDM provides that pre-tax real WACC will be used by NERSA to determine the rate that will be multiplied with RAB to grant licensees a reasonable return. It does not provide details of whether the WACC will be calculated at holding company level or regulated activity level, e.g. calculation of a different WACC for each power station or generation in general within the same electricity generation company.

10.2 The formula for pre-tax WACC provided in paragraph 5.14.2.1 does not show the cost of debt (Kd) component. The formula should be:

$$WACC = [\, \boldsymbol{Kd} \times g) + \{Ke \,/ 1{-}tc \times (1 - g)\}]$$

Where:
Kd – cost of debt
Ke – post tax cost of equity
g – gearing
tc – corporate tax rate

In addition, it is not clear why NERSA is proposing a change from post-tax real WACC to pre-tax real WACC.

Annexure B

Responses to NERSA's stakeholder questions

Stakeholder Questions

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

Answer to question 1:

Unbundled costs will improve the accuracy and relevance of the information submitted to NERSA and facilitate proper tariff setting. The methodology, however, does not explain in detail how all the different unbundled costs (i.e. tariffs, fixed costs such as network connection fees and variable costs such as fuel usage) will be treated. Unbundling the costs will enable tariffs to be cost-reflective, but the methodology is unclear about the steps that will be followed.

Moreover, the current legislation requires NERSA to <u>approve</u> prices/tariffs and not to <u>set</u> the prices/tariffs. The approval of municipal tariffs must be based on the principles enshrined in the existing legislation, which is to allow the licensee to recover the full costs plus a reasonable margin.

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

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

Answer to question 2

(a) We were unable to find 6.13.7, we assume reference was made to 5.14.7 Profit considerations. This section describes a rate of return methodology, in which a profit is based on the RAB value, net of depreciation. This is agreed with. Non-asset based activities a margin setting mechanism based on a percentage of operating costs or benchmarks is suggested. This is also agreed with. NERSA would be advised to consider how trading margins have been regulated under the Methodology to Approve

Maximum Prices for Piped Gas (original of 2011), in which a WACC based approach is used and applied to operating costs.

(b) The determination of the RAB is dictated by the Electricity Pricing Policy (EPP) for reasons explained in the EPP. The approach preferred NERSA is not motivated in the context of Eskom's situation nor is it clear what will be achieved. When implemented properly, a nominal WACC applied over a real RAB (historical cost) or a real WACC applied over a nominal RAB (replacement cost) should yield very similar outcomes. The problem arises when the accounting approach is changed during the life of the asset. Stakeholders like the EIUG and the MCSA were not in favour of revaluing the asset base after the promulgation of the EPP as it increased the depreciation value significantly, without there being any reason to do so. However, now that the MEAV value of the RAB has been established it is not clear how NERSA would be able to go back to historical values. Once again, we reiterate that NERSA should review the MYPD methodology and its implementation thereof to assess whether improvements can be made. We have made certain suggestions to that effect in our overarching comments.

3- a) Stakeholder are requested to comment of data-intensiveness and propose solutions on how licensees can be assistance to be complaint.
b) Stakeholders are requested to comment on the proposed timeframe for licensees to submit their information.

Answer to question 3
The amount of data requested, especially data relating to customer consumption, will require additional systems, such as SMART meters, to be installed by licensees and the data will need to be mined accordingly to provide the required information to NERSA. Further, the data is likely to vary significantly from day to day if customers respond to the proposed price signals by NERSA.

The information required from licensees, in the form that it is required, would require changes to the financial systems (e.g. SAP used by Eskom) that can take up to 2 years to finalise.
The proposed timeframes are too tight for municipalities to meet, even Eskom may require significant time to re-order its systems to provide the required information. As NERSA will be

aware, large regulated entities in the gas sector required some time to adjust its SAP mapping to the RRMs when they were first developed. We would like to reiterate that unbundled cost reporting is prescribed by NERSA in the Regulatory Reporting Manuals, which should be implemented by NERSA without delay.

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

a) Are these representatives?

b) Are there others we should consider?

c) What are your specific needs that should be addressed? Please provide data/evidence of the needs you believe should be addressed.

d) Is the collection of data a risk to privacy laws? What interventions could be employed to mitigate any risk you believe exists?

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

a) Do you agree with cost reflective tariffs? Please substantiate your answer.

b) Do you agree with the move away from regulating revenue to regulating prices? Please substantiate your answer.

c) Do you agree with setting subsidies (where appropriate) based on cost reflective prices? Please substantiate your answer.

Answer to question 4

a) The proposed customer load profiles are likely to change regularly, possibly even daily when customers respond to the pricing. However, at any given point in time, all customers that are consuming electricity are all responsible for the costs of the electricity produced. Just because some customers have "constant" load (i.e. base load) it does not follow automatically that these customers would pay baseload prices when their demand occurs during peak periods.

b) Yes, customer load profiles will change regularly and there will be others that will have to be considered. We note that Annexure G refers to three basic profiles (industrial, residential and commercial) and there in the South African economy there are likely to be more sub-categories in each class. For instance small industrial, high usage residential, etc. We note that neither the structure of the Ugandan ESI or the customer categories have much in common with South Africa's circumstances. Unbundled prices with appropriate time of use signals and a level of cross-subsidisation that is reduced over time is our preferred approach.

c) The electricity generated at any point in time should be paid for by all customers who are using it at that point in time.

d) Not if data collection is done using appropriate anonymization techniques. We would like to refer to data collected on mobile phone users' typical usage. There is a lot of information available on a particular customer, but only the customers themselves should be able to access the data linked to their profile. For all other uses, such data is rendered anonymous in such a way that individuals are not or no longer identifiable, so that the information is no longer considered personal data.

e) (referred to as (a) again in the questions) As indicated in our overarching comments, the principle of cost-reflectiveness in pricing is supported, as long as 'cost-reflective' refers to economic cost reflectiveness, in which the price equals the average cost during the specific time period (i.e. with a Time of Use element). We have commented extensively on the need to cap and reduce the current cross subsidies over time. Whilst we agree in principle that prices must be reflective of the costs, the manner in which this will be done is not addressed by the methodology in its current form. We also note that the existing Electricity Pricing Policy requires cost reflective prices/tariffs.

f) (referred to as (b)) We don't see how regulating prices rather than revenue is possible in the context of the ERA or even the amended ERA that prescribe that an efficient licensee should be able to recover its capital and operational costs as well as a reasonable profit. Price regulation must be sustainable and to set prices regardless of what the revenues will be is not feasible in a regulated market. In our experience the determination of revenues is the first step for determining the prices so revenue regulation will still be required.

g) Subsidies should be explicit, targeted, and where possible time-limited. In our comments above we have provided extensive comments on the matter of cross-subsidisation.

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

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

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

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

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

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

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

Answer to question 5

a) Load profiles will change daily and even hourly, and the load analysis will have to be a continuous process that will not yield stable tariffs for consumers. It would also require extensive capacity by NERSA to analyze the load profiles as required for the EPDM.

The proposed type of use/load is likely going to penalise households as they have low load factors when compared to industrial large power users. The linking of consumption to type of generation will also penalise domestic consumers whose load profile is mostly aligned with peak times. The existing Time-of Use tariffs can achieve better results.

The proposed templates and workbooks are still to be developed and thus making it difficult to ascertain what the final step of determination of prices and tariffs in the methodology would look like.

The proposed quarterly adjustments are not clearly defined and the processes for implementation of these adjustments are not aligned with the existing legislation that governs the licensees.

Other comments in this regard pertain to the EPDM in general:

- The proposed determination of subsidies is misaligned with the existing subsidy framework and requires customers to prove their subsidy needs. For most customers, especially domestic customers it will be difficult to define their subsidy needs.
- The proposed methodology is for prices and tariffs but there is no indication whether the other charges that are associated with electricity business, such as network charges or demand charges will be included in the determined prices and tariffs or not.
- The proposed methodology does not detail how technical losses will be dealt with in the final tariff and how and where these will be measured.
- There is no clarity on whether the determination of prices and tariffs will be instantaneous or not as the tariff will be calculated based on the type of use, load factor and type of generator technology supplying the load. Assuming though that these would be estimated first, then the changes by customers in their load profiles and types of use will not be catered for immediately.
- There is no clarity on how non-dispatchable or self-dispatching generation (i.e. Solar PV and Wind), will be treated in the proposed merit order dispatch. It is unclear how the earlier REIPPP generators that may have higher prices than some of the later REIPPP generators or other cheaper generators will be treated and how the contracts will be amended, other than the mention of a levy. The use of the marginal costs as a determining factor for despatch is not clarified in the methodology when considering self-despatching generation.

b) If done properly, the load profiles will increase significantly beyond the 4 loads outlined.

c) The installation of SMART meters at all customers' premises will come at a significant cost to the licensees and consumers. If we assume that for instance 10 million customers will require SMART meters at a cost of R3000 per SMART meter, the cost will be around R3 bln, excluding the necessary infrastructure to collect and collate the information. According to the proposed methodology NERSA will be conducting this analysis and setting the prices for the customers. The role of licensees in this process is not explained in the methodology and it therefore appears that NERSA will be making the determinations without the licensees' applications. We do not believe this is a sustainable outcome as the information asymmetry that typically occurs between regulators and regulated entities indicates that the licensed entities have a clear role to play in analysing its costs and proposing price structures.

d) Any method that allows customers to access real-time information and enables them to make real-time decisions will close the information gap that consumers face. NERSA and Eskom can undertake consumer awareness programmes.

e) It appears that in the short to medium term the only way to implement the proposed methodology would be by means of the use of benchmarks. It must be emphasized however, that this approach will penalize those customers that change their load profiles as a response to the pricing signals. We therefore reiterate our call for stronger price signals in time of use differentiation so that customers can adjust their behaviour appropriately.

f) We must remember that customers are not electricity consumption experts and that requiring information from customers in the form that will enable NERSA to set the electricity prices will be difficult, if not impossible. These customers are customers of the licensees, not of NERSA, and the existing codes and laws (i.e. Grid Code, NRS standards, Municipal By-Laws, etc) will have to be changed. NERSA was not established to directly deal with customers, and clearly licensees are best equipped to gather and provide the required information.

g) In our view, SMART meters will be the only solution if customers are to be charged based on their load profile and generators will be re-imbursed by a formula that includes load profiles. The existing methodology uses the above-mentioned demand surveys to design appropriate tariffs for the different consumers.

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

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

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

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

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

Stakeholders are requested to comment on the following:

f) The consumer pricing methodology guidelines.

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

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

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

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

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

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

Answer to question 6

a) Yes, it is fair, benchmarks serve the purpose of grouping customers to different categories and generally reflects the norm and accommodates the outliers. This does not replace the need for time-of-use differentiation and other price signals however.

b) In the spirit of ensuring cost reflective tariffs, it is reasonable to have separate tariffs but how these tariffs are applied to those who benefit is not addressed in the methodology. It can be argued all customers benefit and therefore the costs must be shared amongst all customers c&d) There is insufficient clarity in the ERA Amendment Bill to asses which part of the market will remain regulated, what the role of the CPA will be and how the costs are supposed to be apportioned. We expect that the market will for the foreseeable future be a dual one, with one part regulated supply (comprising the legacy PPAs) and another part being unregulated (comprising a large Over-The-Counter market for bilateral trade and the Day Ahead market). It is likely that many customers will purchase via both platforms and the cost of the legacy IPPs will therefore be shared by all customers that take part in the regulated portion of the market. It is not entirely clear why the costs would have to be disaggregated and be recovered via levy, when the regulated part of the market can continue to recover the IPP costs via cost averaging and rate of return regulation.

e) Price reviews in the South African context should be done annually. Whilst in other ESI's it may be appropriate to have more frequent reviews, for instance if the generation mix has a large share of primary energy with highly variable prices (e.g. oil and gas) more frequent reviews may be reasonable. In the South African ESI however, the largest primary energy source is coal, which can be purchased on long-term fixed contracts. Quarterly or monthly price adjustment would render the management of electricity costs for large users even more problematic than it is at present. In our overarching comments we have provided indications of how the current MYPD implementation can be improved to prevent the out-sized annual Regulatory Clearly Account settlements.

f) The consumer pricing methodology is unclear and there are other costs and consequences that it does not cater for, such as reliability and security of supply. We propose that the MYPD methodology and implementation be reviewed and that the causes for price instability be identified so that these can be addressed by means of either an improved MYPD or a different methodology. The current methodology lacks detail and an impact analysis.

g) The ToU approach is fair to all stakeholders including customers and licensees.

h) The Type-of-use approach is untested and will be irrelevant as soon as consumers change their load profile.

i) The Time-of- Use pricing signal is specifically aimed at providing signals that will make customers make informed choices about their consumption. During peak times, all customers contribute to that peak and should be charged accordingly.

j) The ToU approach is the most relevant and sends the appropriate pricing signals.

k) The aim of economic regulation is to mimic competitive outcomes, to arrive at efficient prices. However, the methodology does not provide detail on how this will be achieved. The Weighted Average Tariff Load does not appear to be any different to the manner in which prices with appropriate time of use signals should be determined under the MYPD methodology. We must remember that a competitive market may have highly unfavourable outcomes for users, especially when a market is introduced in a supply-constrained environment. In our view it is clear that licensees will respond to the market forces, hence there will be no reason for the so-called base-load power stations to operate during the traditional baseload periods when higher returns are available during peak periods and similarly non-dispatchable power will be encouraged (by the high prices) to add storage and become dispatchable. Certain loads can be reserved for certain customers in a bilateral context only, and this is not likely in a Day Ahead market. It is not clear how exactly NERSA intends to mimic a competitive market by the use of the Weighted Average Tariff Load approach and we are concerned that this idea appears to emanate from a country with a much less sophisticated ESI. The merit order should be administered by an independent TSO so that the least cost options, save for some self-dispatch and other limitations, are automatically favoured. This requires enhanced oversight of licensees by NERSA, which we would support.

k) Time of Use differentiation is appropriate.

Annexure E onwards Stakeholder Questions

Question 1 para 11.5.2

1- Stakeholders are requested to comment on generation PowerStation information as detailed in table 2 above. Total nominal capacity will be used as a denominator in determining the tariff.

a) Is the information sufficient to understand general power station information of each power station?

b) Is the use of nominal capacity as a denominator appropriate in tariff determination?

Answer to question 1

a) A denominator in a price determination process for generation should be the GWh (net), as planned in the price approval process. NERSA is encouraged to scrutinize the projections by Eskom and other licensees and independently establish the demand forecast so as to prevent under-recoveries and large balances on the RCA. In order to ensure revenue regulation objectives are achieved these projections must be reconciled with the actuals once audited numbers are available.

b) Yes.

c) No, it is not, because the price should be established as an average for net energy produced.

2- Stakeholders are requested on the content of RAB information required from licensees, as shown in Table 3. NERSA is of the view that an evaluation method other than historical costs should be avoided.

a) Will the information be sufficient for NERSA to understand costs related to RAB for tariff determination? If not, what other information could be included?

b) Should a licensee be granted freedom to choose its preferred approach, and what is the most appropriate evaluation approach?

Answer to question 2

a) Please refer to our answers to the earlier question 2 above. NERSA should implement the Regulatory Reporting Manuals and where required improve on them.

b) The current EPP prescribed the asset valuation methodology, which is a replacement value method. Both methods can provide appropriate prices/tariffs if implemented consistently. We would prefer historical costs, but this does not appear possible at present.

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

Answer to question 3

Note that in our expectation a share of the market will remain regulated in future, whilst another part of the ESI will be contracted via bilateral contracts or via trading platforms. The information is required for the regulated part of the ESI only.

The information outlined is a good start. Additional information should be requested on coal burn averages for the current and previous years, the types of contracts that coal is purchased on, the tenure of such coal contracts, etc. to obtain a more detailed view of the actual cost of coal purchases, handling and use in the power station. This should be done for each fuel. It is highly appropriate that this information should be provided on a station basis. In order to ascertain whether these costs are sufficient, NERSA should utilise benchmarks, the EPRI report and time series analysis for the same station.

4- Licensees are requested to comment on the format and details contained in table 5 above on relating to operation and maintenance.

a) Is the information required on from licensee sufficient and appropriate to have full underrating of the costs and for tariff setting purpose?

Answer to question 4

a) Note that in our expectation a share of the market will remain regulated in future, whilst another part of the ESI will be contract via bilateral contracts or via trading platforms. The information is required for the regulated part of the ESI only.

The information outlined is a good start. Additional information should be requested pertaining to the detailed breakdowns of the cost categories per power station, e.g. materials costs should be dis-aggregated to lower level categories according to type of equipment, maintenance should be dis-aggregated according to unplanned and planned maintenance, etc. In addition, NERSA would be well-advised to benchmark the costs or ascertain whether Eskom in particular has obtained quotations from contractors when undertaking maintenance as a means to check the cost-effectiveness of the expenses.

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

Answer to question 5

a) Note that in our expectation a share of the market will remain regulated in future, whilst another part of the ESI will be contract via bilateral contracts or via trading platforms. The information is required for the regulated part of the ESI only.

   The information outlined is a good start. It is not clear what 'commercial costs' would be, perhaps this requires further explanation.

b) Additional information should be requested pertaining to the allocation of the shared costs and the determining cost driver it is based on. Ideally NERSA should approve a proposed allocation of shared costs, e.g. based on GWhs sent out per station. We would also expect that at the Group level, greater detail is provided wrt professional fees ('strategic and consultancy costs') especially as there has been significant corruption associated with such procurement by Eskom as revealed by the Zondo Commission. It would appear that in future there will be costs associated with participation in the Day Ahead and other markets that will be established (e.g. technology costs) which should also be carried by all stations. There may be other corporate services that are provided by the Group that are to be recovered from individual power stations, such as the corporate legal counsel, company secretary, HSEQ compliance, etc. NERSA is encouraged to request highly detailed breakdowns of the corporate costs, especially as incurred by Eskom, so that the Regulator can determine the efficiency of these costs.

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

Answer to question 6

a) The transmission system data and IPP information as outlined should be available. Note that in our expectation a share of the market will remain regulated in future, whilst another part of the ESI will be contract via bilateral contracts or via trading platforms. The information is required for the regulated part of the ESI only.

b) The question is not entirely understood. The IPP information should be available to the TSO in a disaggregated manner (that is not combined with Eskom generation information). As the IPPs are generators their information should be part of generation information and provided to NERSA.

c) Fixed costs should be allocated to all customers based on their use of the capacity. Costs are generally allocated to different customers groups equitably with the necessary allowance for any subsidies deemed appropriate.

d) Taking into consideration the characteristics of the transmission system, a combination of the above is typically appropriate to ensure equity amongst customers and minimize penalties for customers located in areas that are far from the generation points. However, for efficient price signals we believe tariffs based on congestion levels would yield the most useful outcomes. Please refer to our answer to question 26 below. Transmission costs should be calculated and apportioned based on capacity (MVA and MW), time of use and congestion on the network.

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

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

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

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

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

Answer to question 7

a) In a regulatory context, assets can be valued in a nominal or real manner (that is replacement value, or trended historical cost, as compared to historical cost) as long as the accompanying WACC is determined in the opposite manner. This means that for a nominal RAB one would use a real WACC and that for a real RAB, one would use a nominal WACC. As the Electricity Pricing Policy prescribes that replacement values must be used, it seems NERSA does not have a choice. The methodology will only yield more or less the same outcomes if the methodology is followed for the economically useful life of the asset. Changing valuations halfway through the economic life (as was done for Eskom in response to the EPP promulgation) distort the return on and return of capital schedules. We would prefer trended original cost over Modern Equivalent Asset Values, and note that the EPP specifically indicates that replacement values must be used, thereby giving NERSA the leeway to utilise trended original cost as a replacement value. MEAV methodologies involve a lot of discretion and are susceptible to manipulation. Trended original cost does not suffer from the same problems and provides stable prices.[3] We would encourage NERSA to look into trended original cost as an alternative to MEAV asset valuation methods.

b) NERSA can develop incentives in the price methodology for high capital efficiency in the regulated part of the ESI (calculated by dividing the average value of output but the rate of expenditure for the same period of time). This could be a higher allowed WACC when capital investment targets are reached.

c) Please refer to our answers to question 26 (the second 26) below.

[3] https://www.osti.gov/biblio/6005086-comparison-original-cost-trended-original-cost-ratemaking-methods.

d) Based on consumption.

e) Please refer to our answers provided in question 6 d).

9[4]- a) How can the efficiency of operation and maintenance cost be taken into account.

Answer to question 9

It is absolutely imperative that NERSA establishes efficient costs for all licensees active in the regulated part of the ESI, by means of benchmarking, based on independent sources of information (e.g. consulting engineers contracted to perform studies for NERSA), using the EPRI report etc. once these efficient levels have been established, NERSA can disallow costs that exceed these levels or provide an incentive when Eskom or other licensees meet their targets, e.g. by profit sharing, a temporary higher WACC etc.

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

Answer to question 10

a) No, they should be shared across all users.

b) All users cause and make use of ancillary services. It is important to align the cost recovery for ancillary services with the design of the Day Ahead and reserve market as indicated in the ERA Amendment Bill and the Amendment Act that will ultimately result from it. The provisions pertaining to 'balance responsible parties' refer. At present it is not clear whether in the design of the market the ancillary services costs are intended to be socialized. In our view, the costs of ancillary services should be socialized and recovered from all users in accordance with their use of the system.

[4] It appears that the numbering went wrong in the consultation document. There is no question 8.

c) It would appear so.

d) Yes.

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

Answer to question 11

It would appear that the System and Market Operator will be licensees and therefore guaranteed the same revenue regulation of S15(1) as other licensees under the ERA. The profit should be commensurate with the risk of the activities undertaken, or in other words: reasonable for the asset class involved. Note that due to the historic bundling of the various activities under Eskom, we are of the view that the Market Operator and the Transmission System Operator should be different entities. They can both remain state-owned but the Market Operator should be established outside of Eskom. The TSO should similarly be unbundled for Eskom to prevent any favourable treatment of Eskom subsidiaries vis-à-vis the rest of the market.

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

b) What costs is a Market Operator likely to have? Is it your view that the future Electricity Industry structure will have a Market Operator separated from the Independent System Operator?

Answer to question 12

a) This information should be available. If it is not currently available from regulated entities, NERSA should make this information part of the RRMs. Note that in our expectation a share of the market will remain regulated in future, whilst another part of the ESI will be contracted via bilateral contracts or via trading platforms. The information is required for the regulated part of the ESI only. In the design of the market, ancillary services should also be provided for. In that part of the ESI, market for ancillary services will be determined by the market.

b) The market operator will have technology costs, HR costs, Finance and similar corporate overhead costs. We prefer a market operator that is separate from the independent system operator for reasons provided above.

13-a) Based on the above information requirement, do you foresee any risk of the information requested being unavailable or insufficient or not currently being collected in this form or to this detail?
b) Are there other ancillary services that would be required in the near future that are not listed above?

Answer to question 13

a) This information should be available. If it is not currently available from regulated entities, NERSA should make this information part of the RRMs.

   Note that in our expectation a share of the market will remain regulated in future, whilst another part of the ESI will be contract via bilateral contracts or via trading platforms. The information is required for the regulated part of the ESI only. In the design of the market, ancillary services should also be provided for. In that part of the ESI, market for ancillary services will be determined by the market.

b) There may be. The list appears complete at present.

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

Answer to question 14

a) The question is not well-understood. Distribution network operators should undertake cost of supply studies to establish their costs and NERSA should utilise Data Envelopment Analyses or other appropriate methods to establish efficient cost levels for these licensees. Due to differences in network age, topography etc, the distribution costs of individual municipalities may differ from Eskom's distribution costs.

b) We agree that the costs of providing network services should be separated from trading costs. We further urge NERSA to facilitate trading over Eskom and municipal networks and to enforce non-discriminatory access to the transmission and distribution grids which is currently a hurdle to the development of the ESI.

c) This question is not well-understood. Use of system charges are paid by customers and this should be paid to distribution network operators, separate from their trading activities. (distribution network operators should be reimbursed for their costs in accordance with the ERA, and in their capacity as traders, be reimbursed for their trading activities. These activities must be split.) With respect to surcharges that municipalities may impose, we believe that a fundamental overhaul of the municipal revenue arrangements in South Africa is necessary but understand that much of this is outside of NERSA's control. We encourage NERSA to advocate for a reduction in the role electricity surcharges in municipal revenue generation by indicating what the costs of this approach is to users and to the economy as a whole.

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

Answer to question 15

The question is not well-understood. The cost breakdown in table 30 of the consultation paper appears to be in order. Technical distribution losses are determined by engineering models and can be verified through meter readings.

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

Answer to question 16

Existing wheeling arrangements should be based on NERSA-approved wheeling tariffs based on Cost of Supply studies. We encourage NERSA to strictly enforce the Cost of Supply study requirement for distributors and to ensure that distributors provide non-discriminatory access to their grids at regulated wheeling tariffs.

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

Answer to question 17

a) please refer to the answers provided to question 2 above.
b) historical cost.

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

Answer to question 18.

The costs are appropriately identified. Perhaps a higher level of dis-aggregation could be included. These identified costs should not be a closed list as some cost line items may vary depending on network design and technology used.

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

Answer to question 19.

The information outlined is a good start. It is not clear what 'commercial costs' would be, perhaps this requires further explanation.

The operating cost categories for other support services and share of corporate services are relevant but not exhaustive, as they vary depending on the structure of the business model. Therefore, the list should allow for addition of more cost categories.

In particular, additional information should be requested pertaining to the allocation of the shared costs and the determining cost driver it is based on. Ideally NERSA should approve a proposed allocation of shared costs, e.g. based on GWhs sent out per station.

We would also expect that at the corporate level, greater detail is provided wrt professional fees ('strategic and consultancy costs') especially as there have been indication that such procurement areas are associated with the risk of corruption. It would appear that in future there will be costs associated with participation in the Day Ahead and other markets that will be established (e.g. technology costs) which should also be carried by all distributors that are also traders. There may be other corporate services that are provided by the corporate level that are to be recovered from various customer categeories, such as the corporate legal counsel, company secretary, HSEQ compliance, etc. NERSA is encouraged to request highly detailed breakdowns of the corporate costs, so that the Regulator can determine the efficiency of these costs.

20- a) Stakeholders are requested to advise if the required information in respect of the trading activities sufficient to carry the required analysis;
b) Stakeholders are requested to clearly identify the costs related to trading activities and separate those costs from the distribution activities.

Answer to question 20

a) The information required to analyse the trading activities should also include detailed information on cost of sales i.e.

- Forecast volumes; and
- Tariffs incidental to volumes being sold.

b) Electricity traders would not ordinarily have network assets, and if they do it would be insignificant and limited amounts of non-network assets such as buildings, IT equipment and furniture. Therefore, all the costs incidental to operating distribution network assets would fall under distribution activities.

The identification, separation and classification of these costs should be done in terms of the prescribed Volume 1 and Volume 2 of the Regulatory Reporting Manuals for the electricity industry.

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

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

Answer to question 21

a) For the unregulated part of the market, we believe it is not necessary for NERSA to regulate trading margins, especially as the customers are not captive customers and therefore will not enter into PPAs with traders if their prices are not competitive. For the regulated part of the market, NERSA should look to having an efficient and light-handed approach e.g. to indicate that traders can sell at prices that are at or below the customer's alternative Eskom or distributor price. Should higher prices be required in the regulated part of the market, traders can be required to apply to NERSA for approval of such prices in accordance with the prescripts of the ERA.

   Alternatively, it is important to remember that regulatory interventions aim to mimic market forces in the absence of adequate competition so as to produce efficient outcomes. Therefore, NERSA could take the approach that it should only set the trading margin if it has been established that the competition in the market is ineffective.

b) The denominator used to translate the costs into a trading margin should be the volumes used to determine the cost of sales.

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

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

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

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

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

Answer to question 22

a) A trader should be allowed to recoup on its investment in assets and make a profit commensurate with risk. Therefore, all the assets used in its trading activities should form part of its trading RAB when determining the margin. Other costs such as bad debts, depreciation etc., should be allowed as a pass-through in the operating expenses.

b) The nominal Weighted Average Cost of Capital (WACC) of the trader should be the trading margin (%) since all other expenses are allowed to the trader as a pass-through. In so doing, NERSA will be ensuring that the return on investment as derived in the cost of capital calculation is achieved. The trading margin will be applied to the sum of Cost of Sales plus Trading RAB of that trader plus Working Capital.

Trading Margin = (((Trading RAB+ CoS+ Working Capital)*WACC) + Operating Expenses + Tax ± Clawback))) / VOL
Where:
- WACC = Weighted Average Cost of Capital
-RAB = Regulatory Asset Base
-CoS = Cost of Sales
- VOL = Volumes sold

c) Traders should be allowed to own limited network assets and non-network assets used in trading activities. These should be recovered via the trading RAB component of the trading margin as shown in the proposed formula above. Should the trader invest in distribution assets (other than for instance meters) and operate such assets, a distribution licence would be required.

d) If specific valuations are allowed for traders in terms of the EPP, NERSA should prescribe the approach used to value the RAB. Otherwise, the EPP will need to be amended to allow NERSA greater discretion to guard against gold-plating of assets and rate-shopping to inflate the RAB.

e) See our earlier comments in this document on the prescription of valuation methods in the EPP. To fully compensate Utilities for time-value-of-money and allow for a smooth recovery of investment over time, NERSA should consider the Trended Historical Cost method where the index used to trend the RAB is reflective of the cost drivers for asset prices over time.

23- Since trading is not asset based but rather knowledge based;

a) Should the financial assets (i.e. IT systems, meters, inventory, bad debts) be used to determine the margin?

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

c) What will be an allowable cost if costs associated with trading are allowed (i.e. bad debts)?

d) Is it a good incentive for paying customers to be penalised for the rest of the non-paying customers?

Answer to question 23

a) See response on 22(a).
b) See response on 22(b)
c) All operating costs, including provision for bad debts, that are efficiently and prudently incurred by the trader should be allowed as a pass-through in the trading margin. The operating costs to be allowed should relate to charges by the trader in covering a range of trading activities. These operating costs should be grouped and reported to NERSA in accordance with the RRMs.
d) Although bad debt allowance may be viewed as penalising paying customers, if not allowed, it will lead to under-recovery of costs incurred in providing trading services. However, the maximum bad debt allowance should be prescribed by NERSA and benchmarked against the levels of an efficient operator. These should also be audited as prescribed by the RRM Volume 1.

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

Answer to question 24

a) The regulated entity should report transparently its costs associated with hedging in terms of the GAAP/IFRS standards. These costs should be allowable, and NERSA should only disallow costs incurred in speculative trading in financial instruments.

NERSA should also prescribe how these losses/gains from financial instruments or hedging should be apportioned to different classes of customers over time to avoid rapid fluctuations in tariffs/margins.

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

a) Provide your own views on NERSA's list of the classification of the costs into fixed and variable.

b) How to split of fixed costs or allocation of fixed costs to customers based on consumption?

c) Under transmission costs comment on which portion of an ancillary service cost can be socialised (out of pocket costs) and which portion can be carried by customers.

Answer to question 25

a) The split is appropriate. Also refer to volume 1 and 2 of the Regulatory Reporting Manuals.
b) Fixed costs can simply be divided by the GWhs produced (net) to arrive at an average contribution to fixed costs that must be recovered from each kWh.
c) The distinction between socialized and customer costs in the question is in our view incorrect. Socialised costs are recovered from all customers, e.g. based on consumption or capacity consumption. The alternative is a system in which costs are attributed to specific customers or loads. In our view all ancillary services costs must be recovered based on consumption from all customers.

26[5]- a) How should NERSA deal with cold-reserved plants and ancillary service costs?

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

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

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

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

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

[5] The numbering in the consultation document refers to two separate questions 26.

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

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

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

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

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

Answers to question 26:

a) Please refer to our answers to questions 6b, 10 b and 13 a and b.

b) Add the cost of the call reserve plant to the cost of electricity supplied during the relevant intervals and divide the resulting total by the number of GWhs produced to arrive at an inclusive cost per kWh.

c) as in b above, add the costs to the generation costs to arrive at an inclusive cost per kWh.

d) Wheeling charges should be applied for by distributors and transmission operators based on disaggregated cost of supply studies. Such costs can then be passed through to the end user.

e) In our view transmission and market operation functions should be provided by separate entities. Alternatively, the costs can be bundled and divided by the GWhs transmitted to arrive at an inclusive cost per kWh.

f) They appear to be in order.

g) This is the correct approach.

h) The question is not well-understood. Energy costs should be calculated by Time of Use.

i) please refer to our answers to the next question. Transmission tariffs should reflect capacity, congestion and time of use.

j) in terms of the ERA, NERSA should regulate the trading margin (S14(d)). In a deregulated market however, customers and suppliers will enter into agreements based on the willing-buyer, willing-seller principle, in which the trading margin will be constrained by the cost of the alternative supply (e.g. SSEG electricity plus trading margin must be less than Eskom supply costs, otherwise no customer would switch). Hence, the trading margin regulation should be limited to the regulated part of the ESI, which is presently being defined by the DMRE.

k) Quarterly reviews would lead to a worse outcome than the status quo for large users as the predictability of prices would be further undermined. Quarterly reviews are appropriate only when input costs are adjusted monthly or quarterly, such as the prices of diesel. Hence a quarterly review would only refer to a portion of the current price buildup. This is also the case in the Ugandan methodology that NERSA bases some of its methodological preferences on. In that regulatory framework, a base tariff is set, to which quarterly adjustments are made to reflect fuel prices and other variables. It must be noted that the generation mix of Uganda (approx. 2 000 MW installed capacity, predominantly hydropower) differs greatly from that in South Africa as does the customer mix (South Africa has a high energy intensity of GDP with significant demand from baseload customers).

26[6]- Stakeholders are asked to consider the aforementioned tariff options and respond to the following questions accordingly:

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

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

c) Distribution tariffs that reflect both the capacity and the distance are being considered. Do you agree with the **transmission**[7] tariffs that reflect both aspects?

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

Answer to question 26:

a) Not necessarily. Whilst transmission tariffs should always reflect the capacity involved a better indicator of congestion (and therefore costs) is the use of a zonal or nodal transmission tariff system, using locational signals, in which transmission over a longer

[6] The numbering in the consultation document refers to two separate questions 26.
[7] We assume this was meant to read: 'distribution tariffs.'

distance in an uncongested trajectory can incur lower tariffs than transmission over a shorter distance in a congested trajectory. We encourage NERSA to develop a nodal transmission tariff framework to accurately give price signals to both supply and demand side participants. This tariff should also be time-differentiated for enhanced price signaling.

b) See the answer in a). transmission zones are appropriate when they reflect the congestion in each zone (or node). A transmission zone is not necessarily equivalent to distance from generation. We encourage NERSA to develop a nodal transmission tariff framework to accurately give price signals to both supply and demand side participants. This tariff should also be time-differentiated for enhanced price signaling.

c) It is assumed that the question refers to distribution tariffs. Whilst in principle the same answers applies, we are aware that determining congestion related tariffs in a small distribution network may be overly complicated. For sophisticated distributors (e.g. Eskom, large metropolitan municipalities) a capacity and congestion based mechanism, as well as a time-differentiated structure would be appropriate. In other distribution areas a postage stamp approach may be the most advanced method feasible due to lack of smart meters, distribution cost data etc. We believe that NERSA must take control of distribution tariff regulation in a more purposeful manner than has been the case to date. A simple postage stamp (average cost per unit) approach would be an improvement to the status quo in which NERSA has refused to approve wheeling tariffs in 2022 for 2022/23 for instance due to its stated lack of a methodology. This is not acceptable. Unless ordered to do so by a Court of law, NERSA should not impose limitations on its own mandate. As per the Electricity Regulation Act, NERSA should regulate all tariffs, and this should be based on rate of return regulation and efficient costs.

d) Absolutely not. We will not delve into the legal issues in these answers as the matter is currently before the Courts and stakeholders' opinions cannot change the outcome of the Court case. The ERA clearly does not provide exclusivity to municipalities to trade in municipal areas. When it comes to the economics of the question, trading services can be provided on a competitive basis, as only the operation of the distribution network is a local monopoly, not the trading aspect. Hence multiple traders can be accommodated, leading to competition. Traders (either those entities that only engage in trading, or those that combine trading with another function, such as generation) enhance competition, allow for efficient and effective development of the ESI, meet the needs of customers and suppliers, facilitate investment and access to electricity, that are all in the objects of the ERA. We therefore believe that NERSA should make a concerted effort to lower the thresholds to licensing for traders and should enforce non-discriminatory access to the distribution grids by ensuring distributors have approved wheeling (DUOS) tariffs and are not able to deny access to the grid for anticompetitive reasons.