Consultation paper on the review of the Distribution charge (D_t) component of Cost Reflective Tariff ("CRT")

هيئة تنظيم الكهرباء - عمان

AUTHORITY FOR ELECTRICITY REGULATION, OMAN

Attachment to the Authority's letter dated 11 November 2019

1. Introduction & Background

1.1 This consultation paper sets out the Authority's review of the current distribution component (D_t) of Cost Reflective Tariff ("CRT") charges. The following equation shows all the components that constitute the CRT charges.

$$\text{Cost Reflective Tariff} = BST_t + T_t + D_t + S_t$$

BST_t	is the cost of energy charges at the electricity Bulk Supply Tariff in year t;
T_t	is a transmission use of system charge;
D_t	**is a distribution use of system charge; and**
S_t	is a charge for the administrative costs of Supply

1.2 The current D_t charge is an energy charge that reflects the average Distribution Use of System ("DUoS") cost per unit for all distribution companies in Oman including Muscat Electricity Distribution Company ("MEDC"), Majan Electricity Company ("MJEC"), Mazoon Electricity Company ("MZEC"), Dhofar Power Company ("DPC") and Rural Areas Electricity Company ("RAEC").

1.3 The D_t charge reflects the cost on distribution networks of carrying out any works, extension, reinforcement of Distribution Systems, or provision, installation, maintenance, repair or disconnection of Electricity Lines, Electric Plants or meters. In addition, D_t charges provide for a reasonable rate of return on capital assuming the Disco performs the functions efficiently.

1.4 Distribution charges plays an important role in the efficient operation of the electricity system and therefore in the overall development of the Omani economy. In addition to facilitating the recovery of the costs of investment and operation of distribution infrastructure, charges can also provide signals for investment requirements and, to the extent that the charges are reflected in end-user tariffs, can also encourage more efficient electricity consumption behaviour.

1.5 D_t charge was set at 7 bz/kWh for all large customers when CRT charges were first introduced in January 2017[1] reflecting the average DUoS for all five distribution Licensees. D_t charge has been kept at the same level during 2018 and 2019.

[1] Introduction of Cost Reflective Tariff ("CRT") was effective 1 January 2017 applied to all large Government, Commercial and Industrial customers who consume more than 150 MW per year.

1.6 The objective of this study is to reassess the current structure of D_t charges and whether possible modifications are required to enhance cost-reflectivity, and to further reflect different customers, characteristics, including voltage-wise differentiation and cost causality.

1.7 As part of the process, an excel based tariff setting tool has been designed to calculate and compute cost reflective D_t charges based on a cost allocation methodology. The tariff setting model has been developed to calculate DUoS charges for each respective Licensee as well as aggregating it for all Licensees.

1.8 A data template and guidance notes was provided to the Licensees requesting information to better understand the allocation of distribution costs between the different voltage levels. The information request included technical (physical) data and cost data for each of the licensees. Based on the information received, the data was used as an input to the tariff setting tool.

1.9 This Consultation Paper presents the step-by-step proposed cost allocation approach to derive cost reflective electricity distribution use of system charges and also presents the proposed charges structure for the different network users. i.e, the different customer groups.

1.10 The Authority values your opinions and seeks your response to this Consultation Paper and the proposals to introduce possible modifications to the current methodology. In particular, the Authority would appreciate your input to the specific questions included at the end of each section.

2. Data Collection & Data Input

2.1 A data template was sent to the Licensees requesting information on physical (technical) data and cost data. The purpose of the data template and data collection is to facilitate the cost allocation process used to compute the cost reflective distribution charges. The template included guidance notes to define each data request item including an illustrative example on how to complete the data template. The purpose was to ensure that Licensees completing the data template understood what was required and to ensure consistency in the data received.

2.2 The requested physical data consists of the physical characterisation of the network and network levels including demand (MW), energy consumption (MWh), embedded generation information, number of customers and network length.

2.3 The data template also includes information on network losses and allocation of operating expenditure (“opex”).

2.4 Information on the allocation of capital costs was not requested in the data template. Information from the Licensees’ Fixed Asset Registers (“FAR”) will be used for the allocation of capital costs.

2.5 As part of the process, the Authority also considered the Licensees price control financial models as they provide information on the Licensees allowed revenues components (opex, capex and return on capital).

3. Pricing Principles

3.1 A number of established principles are commonly applied for designing and setting distribution use of system charges as these play an important role in the efficient operation of the electricity system. These principles are guidelines to ensure that the proposed approach work in the short and long-term interests of the network operators, the network users and the regulator. In our approach for developing the pricing methodology we have taken account of the following principles:

- **Cost recovery**: Licensees should be able to recover their reasonable and efficient operation & maintenance costs as well as capital costs (including an adequate rate of return) as set by the Authority through the distribution charges. Lack of adequate revenues impacts the financial viability of the Licensee, discourages investments and can reduce the quality of supply.
- **Cost causality:** for the efficient use and development of the network, the tariff paid by network users should reflect the cost they impose on the system. In this respect, location, energy consumption, demand and voltage level of connection are significant.
- **Transparency and simplicity**: the methodology for calculating tariff and charges should be transparent and accessible to all stakeholders. This encourages acceptance of tariff revisions and helps ensure that the tariffs are easy to understand and can be implemented.
- **Non-discrimination**: provided that tariffs (or charges) satisfy the above principles, they should be set at a level playing field for all users, and avoid undue differences in the costs charged to different customers, irrespective of ownership or other factors.

Q1. Do you agree with the above guidelines/principles that should be considered for the proposed revision to the distribution use of system charge methodology? In your view, should any other economic principles be considered?

4. Cost Allocation Process

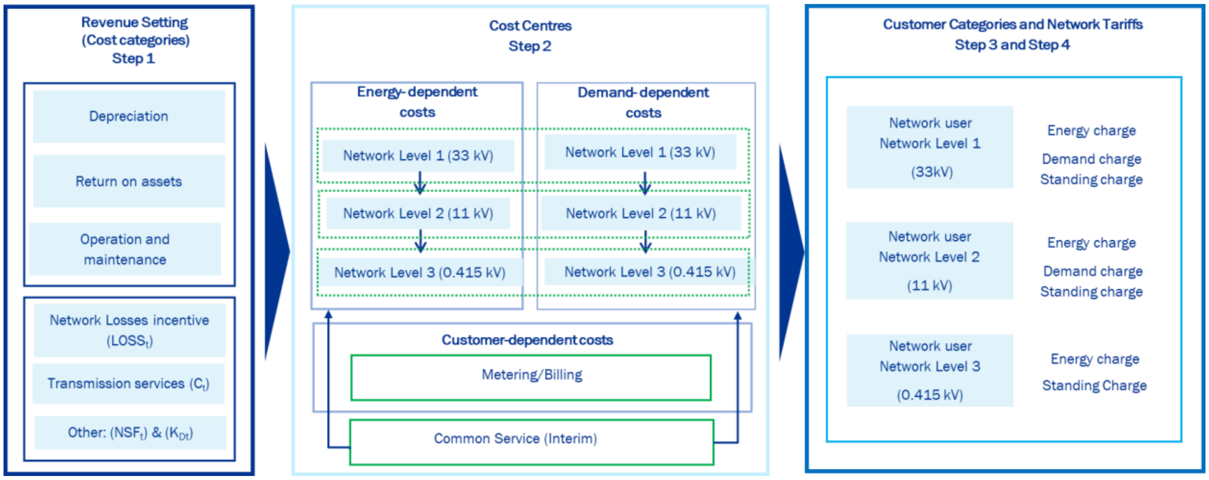
4.1 The objective of the proposed cost allocation approach is to enhance the cost-reflectivity of distribution use of system charges.

4.2 There are a number of key steps when designing cost reflective distribution use of system charges including:

- **Step 1**: establishment of the allowed revenues;
- **Step 2**: allocation of allowed revenues to cost centres and cost type;
- **Step 3**: allocation of costs to network users; and
- **Step 4**:structure and calculation of distribution network charges.

An illustrative diagram of the key steps is shown in the figure below.

Figure 1: Steps for Cost Allocation Process



4.3 The remainder of Chapter 4 describe each step in detail.

Step 1: Establishment of the Allowed Revenues

4.4 The maximum allowed revenue of each Licensee serves as an input to the tariff setting process. These are the revenues that each Licensee would recover through the electricity distribution use of system charges from users of its system.

4.5 Noting the above, the first step in the distribution charges setting is the establishment of each Licensees' allowed revenues. For the purpose of this study, allowed revenues reflect the Maximum Allowed Distribution Revenue ("MADR") based on the current distribution price controls as set by the Authority (D&S-PCR5, DPC-PCR3, RAEC-PCR4).

$$MADR_t = DB_t + C_t + LOSS_t + NSF_t + LF_{Dt} - K_{Dt}$$

Where:

- DB_t means the Distribution Business Revenue and reflects the operating (opex) and capital costs (depreciation and rate of return). The **Opex** consist of the maintenance necessary to provide distribution services, whereas the capital costs comprise of a **rate of return on assets** (regulated asset base x weighted average cost of capital) and a **depreciation** allowance to provide distribution network services. This can be referred to as an asset-related cost.
- The **other components** of the current MADR price control formula include the following:
    - C_t that reflect the charges for connection to a distribution or transmission system;
    - $LOSS_t$ is the Losses incentive mechanism to incentivize reduced distribution losses;

- NSF_t is the Network Security Factor incentive mechanism applied to encourage improved security of supply;
- LF_{Dt} is the Distribution Business share of the License fee payable; and
- K_{Dt} is the correction Factor to account for any over/under recovery (i.e, if the Licensee collects more revenue than allowed)

4.6 After establishing each Licensees' allowable revenues, the next step is to allocate the cost components of the maximum allowed revenues to respective cost centres.

Step 2: Allocation of Allowed Revenue to Cost Centres and Cost Type

4.7 The suggested approach to allocation of allowed revenues consider the nature of the distribution business as they reflect:

- **Cost centres**: physical or virtual places where costs occur. This can be reflected by allocating cost at different voltage levels of connection of the network users, as well as implied metering and billing costs; and
- **Cost type**: differentiating between energy dependent, demand dependent and customer dependent costs.

4.8 The remainder of Step 2 describes the allocation of cost according to (i) cost centres and (ii) cost type.

Allocation of allowed revenue to cost centres

4.9 The objective of differentiating between voltage levels is that the flow of electricity on the distribution networks tends to have a dominant direction.

4.10 For this reason, customers connected at a particular voltage level should not pay for the costs of providing network assets and losses of energy from a lower voltage. In terms of cost allocation, this entails that only the costs associated to the voltage level at or above the level at which a customer is connected should be allocated to the charges paid by that customer.

4.11 The Authority proposes the following cost centres for the purpose of tariff settings[2]:

- **Cost Center 1 (main):** Network level 1 at 33 kV;
- **Cost Centre 2 (main):** Network level 2 at 11 kV;
- **Cost Centre 3 (main):** Network level 3 at 0.415 kV;
- **Cost Centre 4 (main):** Metering and billing; and
- **Cost Centre 5 (interim):** Common Services

[2] The network levels reflect the voltage levels of the distribution system in Oman.

4.12 Cost centres 1-4 are the main cost centres necessary for tariff setting purposes and they represent the cost at different network levels and metering/billing costs (related to distribution network services).

4.13 Allocating MADR components to the main cost centres is undertaken as follows:

- **DB_t (Opex)**: The allowed Opex can be allocated to cost centres based on information from internal cost accounting. However, the Authority is mindful that such information might not be available at this stage, therefore intends to consider alternative options based on the physical parameters of the distribution network. Example of such parameters are network length and installed transformer capacity. These can be used to allocate costs to each of the three network levels. The Opex portion related to the metering/billing will be estimated.
- **DB_t (depreciation and return on assets)**: The Authority believes that asset-related costs (depreciation and return on assets) can be allocated to cost centers using information provided in the Licensees' FAR.
- **Other MADR components**: the Authority intends to allocate these costs as follows:
    - **C_t (transmission connection):** This component consists of the payments for transmission connection and will be allocated to the network levels where the physical connection to the transmission network occurs. These costs will be allocated to cost centre 1 (Network level 1 at 33 kV) and cost centre 2 (Network level 2 at 11 kV) reflecting Licensees' physical connections;
    - **$LOSS_t$ (losses incentive):** This component will be allocated to cost centre 1 (Network level 1 at 33 kV). This approach will properly reflect the dominant physical flow of the energy procured to cover the network losses. The allocated cost will be then distributed to all the network users according to the share of the network losses at each respective network levels; and
    - **NSF_t (Network Security Factor) and K_{Dt} (correction Factor):** the Authority intends to allocate these components to cost centre 1 (Network level 1 at 33 kV). In doing so, the costs associated with NSF_t and K_{Dt} is shared adequately among all the distribution network users as the cost of network level 1 (33 kV) will be distributed to all the network users as described in paragraph 4.10 above.

4.14 Cost centre 5 (Common Services) is related to those costs that are not directly attributable to the main cost centres (for example management, IT, legal services and others). This cost centre was created for data collection purposes only and all costs included in this cost center will be reallocated to the four main cost centers.

Allocation of allowed revenue to cost type

4.15 After allocating costs to the different cost centres, the costs are further allocated according to the cost types: demand-dependent, energy-dependent and customer-dependent.

4.16 Allocation of cost to cost type eases the transition to the next step which is allocating cost to network users.

4.17 The energy-dependent costs are driven mainly by the flow of energy whereas the demand-dependent costs are driven by the demand for network capacity. The customer-dependent costs are driven by the number of customers (meters) connected.

4.18 Allocating MADR components to the different cost types is undertaken as follows:

- **DB_t (Opex, depreciation and return on assets):**
  - For cost centers 1-3 (voltage levels), the Authority intends to apply a pre-determined split to divide the allowed opex, depreciation and return on assets allocated to the three network levels into energy-dependent and demand-dependent; and
  - For cost center 4 (metering/billing) the allowed Opex, depreciation and return on assets will be categorised as a customer-dependent cost.
- **Other MADR components:** The Authority intends to allocate costs related to network loss incentive (LOSSt), network security factor (NSF_t) and correction factor (K_t) to energy-dependent costs. The cost related to transmission connection (C_t) will be allocated to the demand-dependent cost.

4.19 At the end of Step 2, allowable revenues (costs) are allocated to the 4 main cost centres and 3 cost types.

Q2. In your view, does the current cost reporting procedures allow for direct allocation of the cost categories to the suggested cost centers?

Q3. Do you agree that using network length or installed transformer capacity are suitable parameters to act as a proxy to allocate allowed operating costs to the respective cost centers? Please provide us with your views if you have any alternative suggestions

Q4. For the asset-related cost (depreciation and return on assets), the Authority suggests using information from the fixed asset register (FAR). Please provide your opinion on this approach? Are Licensees able to provide information on how to allocate these costs based on internal cost accounting?

Q5. In your view, what are the costs that you consider to be non-directly attributable that should be allocated to the common service cost center?

Q6. Do you have suggestions or comments on how to split the energy-dependent and demand-dependent costs?

Step 3: Allocation of Costs to Network Users

4.20 Step 3 involves allocating the different cost types (energy-dependent, demand-dependent and customer-dependent) from the four cost centre to the network users.

4.21 To allocate these costs to each respective network user, the Authority intends to identify three customer groups of network users:

(i) Network level 1 at 33 Kv;

(ii) Network level 2 at 11 Kv

(iii) Network level 3 at 0.415 kV

4.22 Applying economic pricing principles when allocating energy-dependent and demand-dependent to end-users, namely cost recovery and causality, implies the following:

- network users connected to a particular voltage level should not pay for the costs of providing network assets to those users connected to a lower voltage level of providing network assets; and
- customers connected at lower voltage levels will bear the cost at the network level they are connected to, in addition to the cost from higher voltage cascaded down.

4.23 Customer-dependent cost will be allocated to network users based on the number of customers (meter) rather than based on voltage level.

4.24 The remainder of Step 3 describes how each cost type is allocated to the three customer groups.

Allocation of energy-dependent cost to network users

4.25 The proportion of the energy-dependent cost of a certain network level (and the cost from a higher voltage level cascaded down) will be allocated to the network users according to the share of their consumption in the energy taken from the network level they are connected to.

4.26 For cost allocation purpose, the Authority intends to use the balance of electricity flows across the network levels of the respective Licensees, referred to as the "energy balance". The energy balance is based on data provided by the Licensees in the data template.

Q7. Please provide your views on whether you believe applying energy balance is a suitable parameter for the allocation factor for energy-dependent cost.

Q8. Please provide us with your views on you whether you believe applying an energy consumption is a suitable parameter for the allocation factor for energy-dependent costs related to Network Security Factor & Correction Factor

Allocation of demand-dependent cost to network users

4.27 Demand-dependent costs allocated to customers at each voltage level should reflect each customer's contribution to demand. This generally occurs at times of peak demand, thereby, demand tariff elements are sometimes referred to as "peak" elements or charges. The level of such costs depends on the capacity needed to accommodate peak demand.

4.28 The Authority considers two options for allocating demand-dependent costs:

- **Option 1 – Metered peak demand balance:** uses actual metered values at the time of peak demand at the relevant network level.
- **Option 2 - Connected demand balance:** reflects the level of connected demand at each network level.

4.29 To apply option 1 (metered peak demand balance), the Authority is aware that the availability of reliable data on metered demand depends on the availability of interval metering and data management processes. For this purpose, and if no reliable data is available, the Authority may consider applying option 2 (connected demand balance) or data from energy balance to allocate demand-dependent costs.

Q9. In your view, do you believe that applying demand balance is a suitable parameter for allocating demand-dependent cost?

Q10. Can Licensees please provide your views on whether you can provide the relevant physical data required to derive demand balance based on metered coincident peak demand for each network level?

Q11. Can Licensees please provide your view on whether you can provide the relevant data required to derive demand balance based on connected demand at each network level?

Q12. In your view, which option is preferable and why?

Allocation of customer-dependent cost to network users

4.30 Customer-dependent costs are costs associated with the distribution network services and reflect the costs of meter reading, invoicing and administration of customers. Unlike energy-dependent and demand-dependent discussed above, demand-dependent costs are not cascaded between the different network levels but rather based on the number of customers (meters).

4.31 To allocate the customer-dependent costs and to account for the costs associated with serving the different customer groups, the Authority is considering using the weights associated with servicing the customers connected at each of the three network levels.

Q13. In your view, do you believe that using weighted number of customers connected to each voltage level is an appropriate method of allocating the customer-dependent cost. If so, in your opinion how should the weights be set to reflect for differences in the effort and expenditure required to provide metering and billing services for different customer groups?

Step 4: Structure and Calculation of Distribution Network Charges

4.32 The Authority believes that the proposal for the revision of the distribution charge based on the network level differentiation provides an appropriate balance between providing a more cost reflective charge based on economic pricing principles. This provides an appropriate pricing signal to customers and provides a stronger incentive for customers to manage their demand.

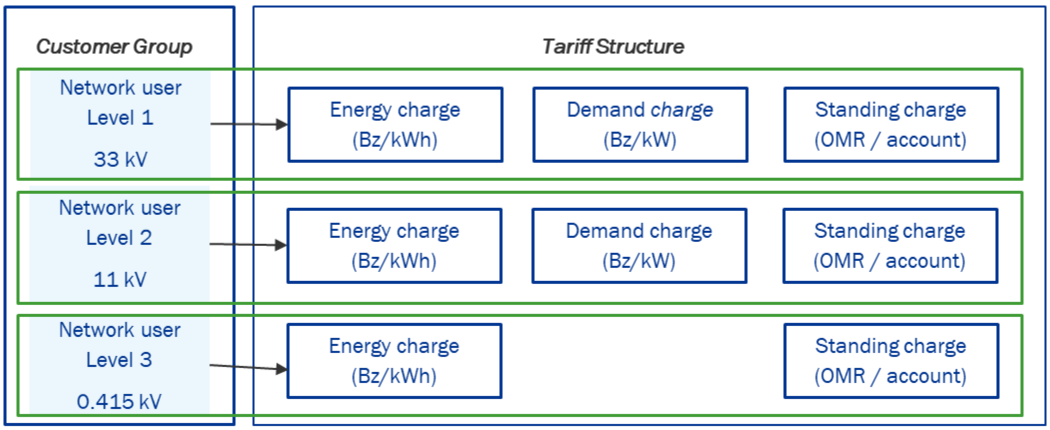
4.33 Step 4 is the final step in the Authority's approach to designing cost reflective distribution use of system charges and describes the Authority's proposal for the distribution charge structure.

4.34 The Authority also proposes an interim charge structure that could be adopted in the interim period due to data limitations. This interim structure can be considered until reasonable and reliable data is available to apply the proposed structure. Both proposals are set out below.

Proposal for Distribution Charge Structure

4.35 The Authority is considering the following charges structure:

Figure 2: Proposed distribution charges structure across the different customer groups



Whereby:

- **Energy charge (bz/kWh):** The energy-dependent costs will be allocated to an energy charge. This energy charge will be based on metered energy (kWh) for each respective customer group (i.e, network level 1, network level 2 and network level 3);
- **Demand charge (bz/kWh):** The demand-dependant costs will be allocated to a demand charge. This demand charge will be based on the individual metered peak demand (kW) for each respective customer group; and
- **Standing charge (OMR/account):** The customer-dependent costs will be allocated to a standing charge (or fixed charge). This standing charge will be imposed as a fixed annual charge and can be broken down into payments, e.g. monthly/quarterly made over the year.

4.36 The Authority is considering applying a demand charge for the larger distribution connected customers only (i.e, those connected to Network level 1 (33 kV) and Network level 2 (11 kV)). The demand dependent costs for lower level distributed connected customers (i.e, those connected to network level 3 (0.415 kV)) will be recovered through an energy charge.

Proposal for the Interim Distribution Charge Structure

4.37 The Authority recognises that certain data limitations exist and certain data serves as an important input for a fully-fledged cost allocation model. At this stage, the current available information may not be sufficient to establish reliable cost-reflective demand charges to the details set out in the previous proposal (i.e, energy-dependent, demand-dependent and customer dependent).

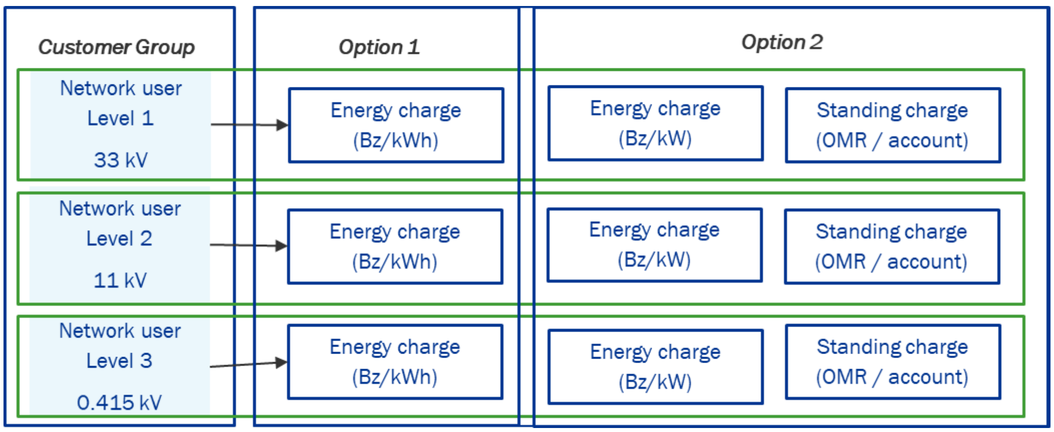
4.38 In this case, the Authority is considering two options for an interim charge structure until the necessary data is made available for a more detailed distribution charge structure.

4.39 The two options proposed for an interim distribution charge structure are as follows:

- **Option 1 – energy charge (Bz/kWh):** whereby all costs will be recovered through an energy charge only; or
- **Option 2 - energy charge (Bz/kWh) + standing charge (OMR/account):** whereby all the energy and demand dependent costs are recovered through the energy charge and customer dependent costs are recovered through a standing charge.

4.40 Figure 3 below presents the interim distribution tariff options:

Figure 3: Proposed interim distribution tariff structure across the different customer groups



Q14. Please provide your comments on the proposed distribution charges structure for the customer groups.

Q15. Please provide your views on the proposed interim distribution charges structure for the different customer groups.

Appendix 1 Consultation questions for Distribution companies and other stakeholders

A1.1 While comments are invited on any aspect of this document, we have highlighted a number of specific questions that stakeholders may wish to respond to. These questions are:

- Q1. Do you agree with the above guidelines/principles that should be considered for the proposed revision to the distribution use of system tariff methodology? In your view, should any other economic principles be considered?
- Q2. In your view, does the current cost reporting procedures allow for direct allocation of the cost categories to the suggested cost centers?
- Q3. Do you agree that using network length or installed transformer capacity are suitable parameters to act as a proxy to allocate allowed operating costs to the respective cost centers? Please provide us with your views if you have any alternative suggestions
- Q4. For the asset-related cost (depreciation and return on assets), the Authority suggests using information from the fixed asset register (FAR). Please provide your opinion on this approach? Are Licensees able to provide information on how to allocate these costs based on internal cost accounting?
- Q5. In your view, what are the costs that you consider to be non-directly attributable that should be allocated to the common service cost center?
- Q6. Do you have suggestions or comments on how to split the energy-dependent and demand-dependent costs?
- Q7. Please provide your views on whether you believe applying energy balance is a suitable parameter for the allocation factor for energy-dependent cost.
- Q8. Please provide us with your views on you whether you believe applying an energy consumption is a suitable parameter for the allocation factor for energy-dependent costs related to Network Security Factor & Correction Factor
- Q9. In your view, do you believe that applying demand balance is a suitable parameter for allocating demand-dependent cost?
- Q10. Can Licensees please provide your views on whether you can provide the relevant physical data required to derive demand balance based on metered coincident peak demand for each network level?
- Q11. Can Licensees please provide your view on whether you can provide the relevant data required to derive demand balance based on connected demand at each network level?
- Q12. In your view, which option is preferable and why?

- Q13. In your view, do you believe that using weighted number of customers connected to each voltage level is an appropriate method of allocating the customer-dependent cost. If so, in your opinion how should the weights be set to reflect for differences in the effort and expenditure required to provide metering and billing services for different customer groups?
- Q14. Please provide your comments on the proposed distribution charges structure for the customer groups.
- Q15. Please provide your views on the proposed interim distribution charges structure for the different customer groups.