Consultation paper on Access Charging Methodology for Self- Supply and Direct Access

هيئة تنظيم الخدمات العامة
Authority for Public Services Regulation

Contents

1. Executive Summary

1.1 The Omani power market is currently transiting toward further reform and liberalisation. The regulated market is looking towards new mechanisms for the supply of electricity outside the remit of the single buyer, the Oman Power and Water Procurement company (OPWP). Specifically, we distinguish between the two types of transmission network users examining options to consume electricity not purchased from OPWP:

- **"Self-supply"** customers (or "self-suppliers") use power which they generate (or "self-generate") and access by generating on-site or via private wire connection.
- **"Direct access"** customers use power served directly by an off-site generator via the transmission system, without going through the spot market or a P(W)PA with the single buyer.

1.2 Against this backdrop, the Authority for Public Services Regulation (APSR) tasked the Oman Electricity Transmission Company (OETC) with designing a system access (or "wheeling") charge which allows customers to generate their own power off-site and wheel it to themselves using the transmission grid, and also allows licensed production facilities to wheel power to entities other than OPWP using the transmission network.

1.3 OETC commissioned NERA Economic Consulting (NERA) to assess and develop proposals for system access charges.

Access Charging Proposal

1.4 Noting the types of transmission network users set out above, different access charges were identified for:

1) wheeling;
2) standby; and
3) customers who may be eligible for exemptions from TUoS.

1.5 The access charges proposals are summarised below:

Proposal 1: Charging TUoS to customers who use the transmission grid to wheel power from direct access generators

1.6 Customers who use the transmission grid to wheel power from direct access generators impose similar costs on OETC as customers that purchase their power from OPWP. In both cases, customers are served by generators located across the transmission grid and use the transmission grid to facilitate the flow of power to their customer site. Therefore, **we propose charging TUoS to customers served by direct access generators.**

Proposal 2: Setting a standby charge on customers who self-supply

1.7 The current TUoS regime overexaggerates incentives to self-supply because OETC recovers all transmission costs through a TUoS charge levied on customers' contribution to coincident system peak. This allows customers with behind-the-meter self-generation to avoid contributing towards transmission costs which OETC incurs to meet their use of the grid at other times.

1.8 To address this, it is proposed that OETC levies a standby charge on customers with behind-the-meter generation, to ensure that self-supply customers pay a cost-reflective share of the costs that they impose on OETC. More specifically, it is proposed that the standby charge recovers the fixed costs imposed on OETC to accommodate customers with behind-the-meter self-generation. This is cost-reflective because OETC incurs the fixed costs to accommodate those customers irrespective of the actual power that those customers draw from the grid during times of coincident peak.

1.9 We propose to tie the charge to customers' potential to demand from the grid during times of coincident peak. Therefore, in addition to TUoS, **we propose to levy the charge on a customer with self-generation at the lower of:** (a) the customer's average self-generation during the triad; and (b) the customer's connection capacity less net demand. The standby charge is set using the fixed costs as stipulated by the Notified Values in OETC's Maximum Allowed Revenue (MAR), and such that a customer with self-generation pays approximately the same towards the fixed costs of transmission as a customer who consumes from the grid during hours of coincident peak.

1.10 We note that one would need to put in place mechanisms to meter self-generation by customers, and such arrangements may require some modifications to the Grid Code. However, we do not anticipate significant technical challenges to implementing the charges, in particular for customers with self-generation.

Proposal 3: Grant specific customers exemptions from paying full TUoS

1.11 The average cost pricing under the current TUoS charges may inefficiently deter customers who cannot cover OETC's average cost but would pay at least the marginal cost that they impose on OETC to accommodate their demand. To avoid such inefficiencies, **it is proposed to exempt some customers from paying TUoS and instead charge them the marginal cost that they impose on OETC.**

1.12 **We propose offering exemptions to customers that use the transmission grid to export power outside of Oman,** and customers which policymakers determine on a case-by-case basis to be "strategic" domestic customers that bring wider benefit to Oman.

1.13 The charge for these exempt customers would vary depending on whether they require OETC to invest in its network to accommodate their demand:

- **Exports which do not trigger investments:** We expect that some export demand would not require any investment from OETC to serve (e.g., short-term export transactions). In these cases, we propose to apply a volumetric charge based on the marginal cost that OETC incurs to accommodate energy consumption as set out in its MAR.
- **Strategic customers and exports which require investments:** We propose that customers which trigger network investments are charged the long-run marginal cost that they impose on OETC to facilitate their demand. Strategic customers are identified by the government that is expected to provide longer-term economic benefits. Customers categorised as strategic are subject to government approval.

1.14 In both cases, the proposed charges will encourage efficient use of the grid by allowing exempt customers to enter and contribute only toward the marginal cost of serving them.

2. Introduction & Background

2.1 The Omani power market is currently transiting toward further reform and liberalisation. Currently the market operates principally under a single buyer model, whereby generators serve the market under long-term power (and water) purchase agreements (P(W)PAs) with Oman Power and Water Procurement Company (OPWP). A wholesale electricity (spot) market commenced operation on 1 January 2022 allowing plants with expiring P(W)PA to sell power on the spot market to the single buyer.

2.2 In parallel, the regulated market is looking towards new mechanisms for the supply of electricity that are outside the remit of the single buyer.

2.3 In this paper we distinguish between two types of transmission network user which consume electricity not purchased from the single buyer:

- Customers who choose to **"self-supply"** by using power which they do not access via the transmission system. Specifically, this includes customers that use power which they generate (or "self-generate") and access by generating on-site or private wire connection
- Customers that use power via **"direct access"**. Direct access refers to customers which use power served directly by an off-site generator via the transmission system, without going through the spot market or a P(W)PA with the single buyer. Direct access generators may wish to wheel power onto the existing electricity transmission network to serve their customers. Direct access also provides an option for customers wishing to generate their own power off-site and wheel it to themselves via the transmission system rather than via private-wire.

2.4 Against this backdrop, The Authority for Public Services Regulation (APSR) tasked the Oman Electricity Transmission Company (OETC) with designing a system access (or "wheeling") charge which allows customers to generate their own power off-site and wheel it to themselves using the transmission grid, and also allows licensed production facilities to wheel power to entities other than OPWP using the transmission network. OETC commissioned NERA Economic Consulting (NERA) to assess and develop a proposed system access charge, which have formed the basis of the proposals in this paper.

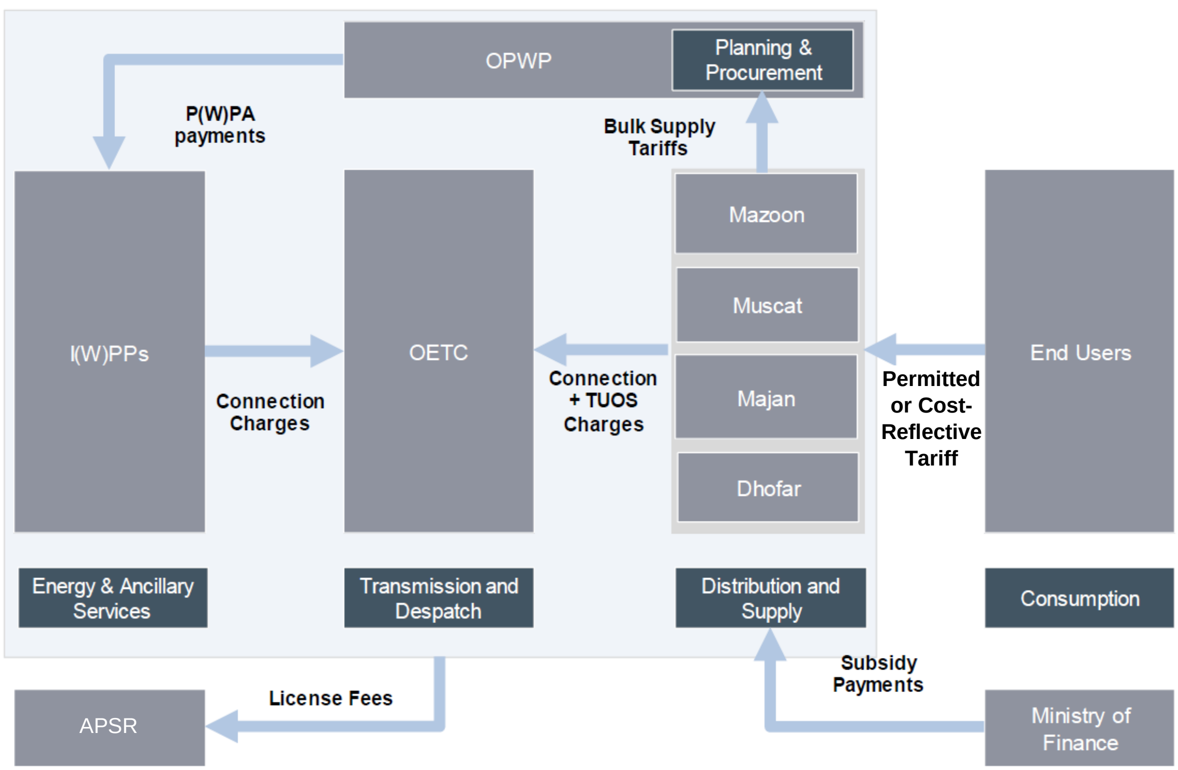
3. Financial flows in the electricity Sector

3.1 At present, I(W)PPs are remunerated entirely through long-term contracts with OPWP. I(W)PPs pay connection charges to OETC, which also receives connection and regulated transmission use-of-service charges from distribution and supply companies to fund their transmission and dispatch activities. The distribution and supply companies in turn earn revenue from sales to end users, subject to price controls, and receive subsidies from the Ministry of Finance to make up the difference between actual and allowed revenue.

3.2 OPWP pays its procurement and overhead costs through bulk supply tariffs (BSTs) charged to distribution and supply companies, while the APSR recovers its costs through licence fees levied on all regulated entities in the sector.

3.3 An illustration of the cash flows within the electricity sector are presented in Figure 1 below.

Figure 1 - Oman electricity sector financial flows



Source: NERA illustration.

Future Changes in the Market Structure

3.4 Electricity generation in Oman (specifically the MIS) is currently transitioning from a centrally operated to market-operated framework. The wholesale electricity spot market (that became operational from 1 January 2022) will serve an increasingly important role as further PPAs expire and new merchant generators come online.

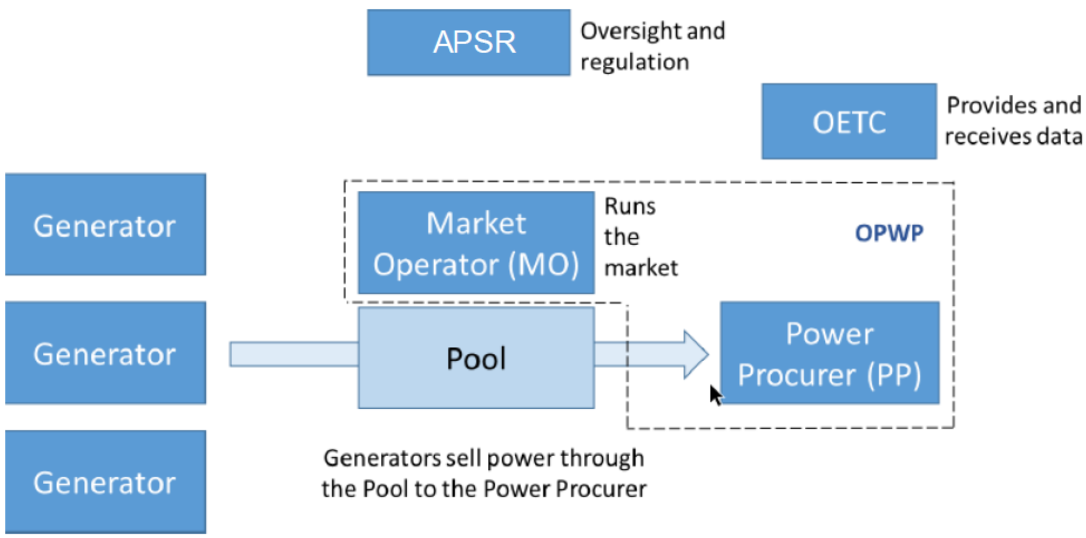
3.5 The wholesale electricity spot market consists of multiple generators selling to OPWP.

3.6 OPWP will remain the central player in the spot market, responsible for developing the market rules, acting as the market operator and retaining a role as the power procurer. The Market Operator is currently a separate unit inside OPWP, separated from OPWP's procurement functions.

3.7 All generators are required to operate in the market[1] .Those with current P(W)PAs submit offers but are remunerated at their contractual rates, while residual demand is served from the merchant supply-stack.

3.8 Figure 2 presents the role of the different entities in the current market structure: OETC is not a pool participant but remains responsible for despatch and takes on new data validation and provision responsibilities.

Figure 2- Oman Electricity Market Structure



Source: OPWP Electricity Market Guide[2]

3.9 In addition to the wholesale market, APSR is currently conducting a study on allowing bilateral sales between eligible electricity generators and large customers.

3.10 An important area for further potential development is the procurement of ancillary services. Currently, ancillary services are provided under the terms of existing P(W)PAs, and are therefore being funded directly by OPWP.

3.11 The mechanism for the future treatment of ancillary services is yet to be developed. In particular, the mechanisms for the provision of ancillary from new merchant generators, which may be called upon in the event that ancillary service demand exceeds that which can be provided by the remaining contracted capacity. However, at this stage, OPWP will continue to take on responsibility for procuring ancillary services, while OETC will continue to have the responsibility of providing and coordinating the services. OETC's dispatch role in the electricity market may also come with increased data reporting and validation responsibilities.

[1] Excluding small generators or those not connected to the MIS or located within Oman
[2] Oman Power and Water Procurement Company, 2017, Oman Electricity Guide Version 1.0, page 6.

4. Overview of OETC's Current Regulatory and Network Charging Arrangements

OETC's Roles & Responsibilities

4.1 OETC's statutory obligations are set out in the Law for the Regulation and Privatisation of the Electricity and Related Water Sector ('Sector Law') and the Transmission and Dispatch License issued by the Authority.

4.2 The Sector Law outlines the functions, powers, and duties of the Licensed Transmission System Operator. Under the Sector Law, OETC can own, finance, develop, operate, and maintain the Transmission System, and is subject to the duty that this be done in an effective and economic manner subject to the duty of Economic Purchase.[3]

4.3 Under the Economic Purchase obligation, OETC must buy any required goods and services on the best available economic terms.[4] Under the Sector Law, OETC can derive revenues by charging a cost-reflective tariff for the use of its transmission system.[5] OETC's Connection and Use of System Charge Methodology Statement (CUSC) sets out the tariffs and outlines any limitations on the tariffs OETC can charge.

4.4 This section outlines OETC's charging regime, under which OETC recovers:

(1) Transmission Use of System (TUoS) charges; and

(2) Transmission Connection Charges (TCC).

Determination of OETC's TUoS Revenue

4.5 The Authority regulates OETC using an RPI-X form of incentive regulation,[6] which involves a Maximum Allowed Revenue (MAR) cap which the Authority intends to "cover the efficient costs of the business and allow the Licensee to earn a reasonable commercial rate of return on invested capital".[7] This following Section provides a brief overview of the price control framework.

The "building blocks" underpinning OETC's MAR

4.6 "RPI-X" regulation was introduced in the UK in the 1980s, and has come to refer to a broad range of different regulatory methods in which allowed prices or revenues are fixed by the regulator for a number of years, and then adjusted over time for changes in inflation, less an "x-factor" representing the extent to which the regulator expects the company's costs to change faster or slower than inflation.

4.7 An RPI-X price control provides an incentive for the company to make efficiency gains. If the company reduces costs faster than the change RPI-X predicts, the company enjoys higher profits until the MAR is reviewed for the next price control.

[3] The Law for the Regulation and Privatization of the Electricity and Related Water Sector – Royal Decree 78/2004
[4] The Law for the Regulation and Privatization of the Electricity and Related Water Sector – Royal Decree 78/2004
[5] The Law for the Regulation and Privatization of the Electricity and Related Water Sector – Royal Decree 78/2004
[6] RPI refers to the Retail Price Index
[7] The Law for the Regulation and Privatization of the Electricity and Related Water Sector – Royal Decree 78/2004

4.8 OETC's allowed costs are the sum of controllable costs, including operating expenditure; return on capital, and depreciation; and pass-through costs. As part of the price control review, the Authority assesses what it considers to be an efficient level of operating and capital expenditure (Opex and Capex, respectively) for the period covered by the price control.

- **Opex:** APSR sets OETC's allowances through a combination of bottom-up benchmarking, which involves APSR projecting efficient cost levels,[8] and top-down comparison with the Distribution and Supply Licensees.[9] APSR also imposes an ongoing efficiency target through the RPI-X price control in the form of the "x-factor, incentivising OETC to increase its efficiency in order to maintain profit levels.

- **Capex:** OETC earns an allowed rate of return on the Regulatory Asset Base (RAB), which is the value of a company's historical costs that the regulator allows it to recover through future regulated revenues. Assets financed through OETC's capital expenditure allowance enter the RAB, and OETC earns a return on those assets based on the weighted average cost of capital (WACC). The RAB is depreciated over time to reflect the depreciation of assets over time.

- OETC's Maximum Allowed Revenue (MAR) is then the sum of OETC's operating costs and the depreciation of and return on the RAB.

The current price control formula

4.9 Under OETC's current price control (2019-22 inclusive), the MAR is calculated according to the following formula which defines separate revenue allowances for OETC's transmission and dispatch activities:

$$MAR_t = MATR_t + MADISR_t + LF_t - K_t$$

Where:

- MAR_t denotes the Maximum Allowed Revenue in the year t.
- $MATR_t$ denotes the Maximum Allowed Transmission Revenue in the year t.
- $MADISR_t$ denotes the Maximum Allowed Dispatch Revenue in the year t.
- LF_t denotes OETC's share of the Licence Fee in the year t.
- K_t denotes the correction factor in the year t.

4.10 In any given year, OETC's MAR reflects its allowed revenue from its Transmission and Dispatch businesses, plus the cost of any Licence Fee payable to the Authority. If the MAR was over- or under-recovered in the previous period, a correction factor also applies.[10]

[8] Authority for Electricity Regulation, Oman (25 October 2018), Transmission & Dispatch Price Control V: Final Price Control Proposals (2019-2022), para 7.8.

[9] Authority for Electricity Regulation, Oman (25 October 2018), Transmission & Dispatch Price Control V: Final Price Control Proposals (2019-2022), para 7.12.

[10] Authority for Electricity Regulation, Oman (20 January 2020), Electricity Transmission and Dispatch Licence, p. 51.

4.11 The Maximum Allowed Transmission Revenue (MATR), in turn, is the sum of the MATR in the MIS and the MATR in the Dhofar System.[11] The MATR in each system varies according to peak demand, as measured by the Maximum Transmission System Demand (MTSD), and energy demand, as measured by the Regulated Units Transmitted (RUT).

4.12 The weighting in the MATR calculation means that approximately 70 per cent of the revenue is associated with the fixed term in the revenue requirement, with MTSD and RUT each weighted at approximately 15 per cent.[12] The fixed component of OETC's MATR is 71 per cent in 2020.[13]

OETC sets TUoS charges to recover its MAR

4.13 In each year, OETC deducts the amount of other regulated income from the MAR to give a residual to recover from TUoS charges. OETC levies TUoS charges on the demand of transmission-connected customers (e.g. distribution companies) during times of coincident peak in each year.

4.14 More specifically, it levies TUoS on each customer's average demand during the three highest hours of system demand in each year (with the three hours separated by at least 21 days), called the triad hours. The total of customer's average demand across the system during triad each year is denoted the MTSD.

4.15 The calculation of TUoS charges is as follows:

$$TUoS_t = \frac{MAR_t}{MTSD_t}$$

TUoS charges are paid as annual OMR per MW per month charges by customers. In 2021, the annual TUoS charge was set at OMR 16,630 per MW across the year.[14]

4.16 OETC charges customers as follows:

- It forecasts each customer's share of MTSD and uses this to estimate the total TUoS to be recovered from each supplier.
- Each customer is invoiced monthly for this amount.
- When actual values, as opposed to forecasts, for the MTSD and each customers' share of peak demand are available, OETC recalculates the TUoS charge for the year to reflect the actual values and invoices each customer.
- The charges are reconciled in the December invoice.

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[11] Authority for Electricity Regulation, Oman (25 October 2018), Transmission & Dispatch Price Control V: Final Price Control Proposals (2019-2022), para 1.39-1.40.

[12] Authority for Electricity Regulation, Oman (25 October 2018), Transmission & Dispatch Price Control V: Final Price Control Proposals (2019-2022), page 2.

[13] Where we calculate the fixed component by taking the total of notified values a_t and d_t, and dividing by OETC's MAR.

[14] Authority for Public Services Regulation, 2021 Cost Reflective Tariffs, Statement of Charges.

Determination of OETC's TCC Revenue

4.17 OETC receives revenue from Transmission Connection Charges (TCC) in addition to TUoS charges. In most cases, OETC is responsible for constructing and maintaining the Connection Asset connecting the User Asset to the Shared Asset owned by OETC. The Connection Charges are designed to recover the costs associated with the Connection Asset directly from the connected customer.

4.18 The annual Connection Charges to customers are composed of the Capital Charge and Transmission Running Charge (TRC). While the Capital Charge aims to recover the initial investment cost of the connection asset, the TRC is in place to recover the operation and maintenance costs of providing the connection.

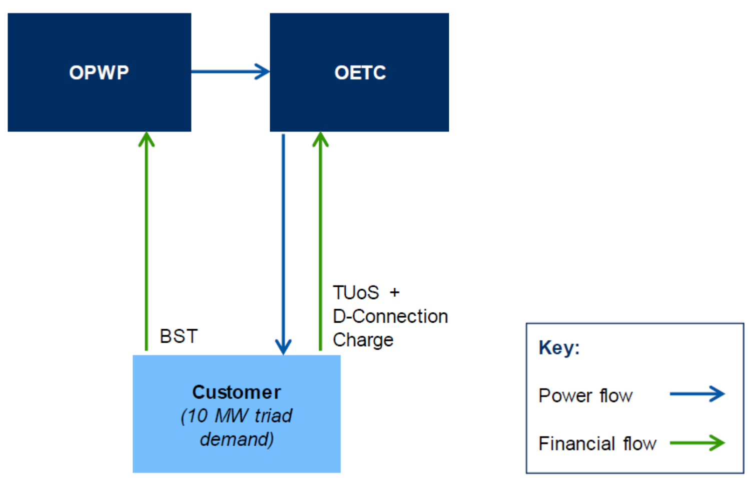
4.19 For both the TCC and TRC, the user can opt out from the annual payment scheme outlined above. Users can avoid the annual payment by either providing the operation or connection construction service themselves, or by paying the Capital Charge up front.

4.20 The Authority does not directly regulate the Connection Charges collected by OETC, but the Weighted Average Cost of Capital (WACC) WACC used to calculate the annual Capital Charge and the allowed connection asset Opex in the TRC factor are set by the Authority in the price control.

Illustration of Current Transmission Charges

4.21 Currently, large customers buy power from the licensed supplier at a Cost-Reflective Tariff (CRT) which includes the BST. Customers also pay TUoS on average triad demand, per the current arrangements. The customers also pay demand-side connection charges. Figure 3 below provides an illustration of the energy and financial flows between OETC, PWP and a particular customer.

Figure 3- Existing Access Charging Arrangements for OPWP customers



Source: NERA illustration

4.22 Figure 3 above summarises the payments due to OETC. For numerical simplicity, we assume that the customer demands 10 MW from the grid on average during the triad hours.

Table 1- Proposed Payments to OETC for OPWP Customer

Item	Calculation
TUoS	$TUoS_t \times 10\ \mathrm{MW}$, per existing arrangements
Demand connection charge	Customer pays a demand connection charge on a bespoke basis, per existing arrangements
Generation connection charge	Any generators which OPWP uses to serve demand will require to pay connection charges to OETC (note, these are not pictured in Figure 3 above)

Source: NERA analysis

Q1. Do you agree with the proposed charging basis for wheeling charges?

5. Motivations for an Access Charge

5.1 As noted previously, the Omani power market is currently transiting toward further reform and liberalisation and is looking towards new mechanisms for the supply of electricity outside the remit of the single buyer. Specifically, we distinguish between the two types of transmission network users examining options to consume electricity not purchased from OPWP:

- **"Self-supply"** customers (or "self-suppliers") use power which they generate (or "self-generate") and access by generating on-site or via private wire connection.
- **"Direct access"** customers use power served directly by an off-site generator via the transmission system, without going through the spot market or a P(W)PA with the single buyer.

Criteria for efficient tariff design

5.2 In order to guide our approach to design the access charge, we adopt tariff design criteria or principles that a well-designed access charge should meet. The following criteria, based on Bonbright's principles, have been considered:

- **Send Efficient Price Signals:** The access charge should send appropriate price signals that reflect the long-run costs and benefits of providing customers with access to the system. To promote economically efficient consumption decisions, the charge should be structured to inform customers over the costs they incur to wheel power. The access charge should not subsidize wheeling by signaling lower long-run costs that OETC actually incurs to transmit power across its network;
- **Ensure Total Cost Recovery:** We note that irrespective of the revenue recovered from access charges, TUoS charges would be set to allow OETC to recover its Maximum Allowed Revenue each year. Nonetheless, the important principle to maintain (as noted above) is that when serving a customer through its grid, OETC should set charges that at least ensure it recovers its marginal costs of integrating a customer and serving it through its network;
- **Be Fair and Equitable:** The access charge should be fair, objective, and equitable such that it avoids undue discrimination and minimizes inter-customer subsidies. If the access charge sends price signals that reflect the costs of providing access to customers, thereby meeting the efficient price signal criterion, then that access charge design is likely to be both fair and objective. A charge that reflects the costs of providing transmission would also be equitable because differences in tariff costs across customers would reflect the costs caused by those users;
- **Be stable and Predictable:** The charge should be stable and predictable for customers, such that the charge design does not change materially from year-to-year in conditions where transmission usage patterns and transmission costs are not similarly variable across years. However, this should not be prioritized over the principle of sending efficient price signals.

- **Be Practical:** The access charge should be practical so that it is understandable by the sector, and implementable by OETC. For instance, the charge will need to be levied on customer behaviour that is observed or measured by OETC to ensure that it can be billed correctly. The ease and practicality of implementation is an important consideration in the evaluation of potential methodologies to set the charge. Customers need to understand the structure of the charge in order to be able to predict their costs of using the grid, and how changes in their consumption behaviour will result in them paying different charges. This is necessary both to adhere to the principle of fairness (discussed above), but also to ensure customers can respond to the efficient price signals sent in the charge. Therefore, we consider the practicality of the tariff from both the view of OETC and customers in the evaluation of alternative tariff methodologies.

Q2. Do you agree with the above criteria and principles for the development of access charges? In your view, should any other criteria/principles be considered?

6. Proposed Access Charge Design

6.1 The following section outlines the proposed access charge design, based on the criteria and principles for efficient tariff design discussed above.

Wheeling Charges

6.2 Wheeling charges apply to customers that use the transmission grid to wheel power from direct access generators to their site in order to avoid (or reduce) purchasing power from OPWP.

6.3 Customers who use the transmission grid to wheel power from direct access generators impose similar costs on OETC as customers that purchase their power from OPWP. In both cases, customers are served by generators located across the transmission grid and use the transmission grid to facilitate the flow of power to their customer site.

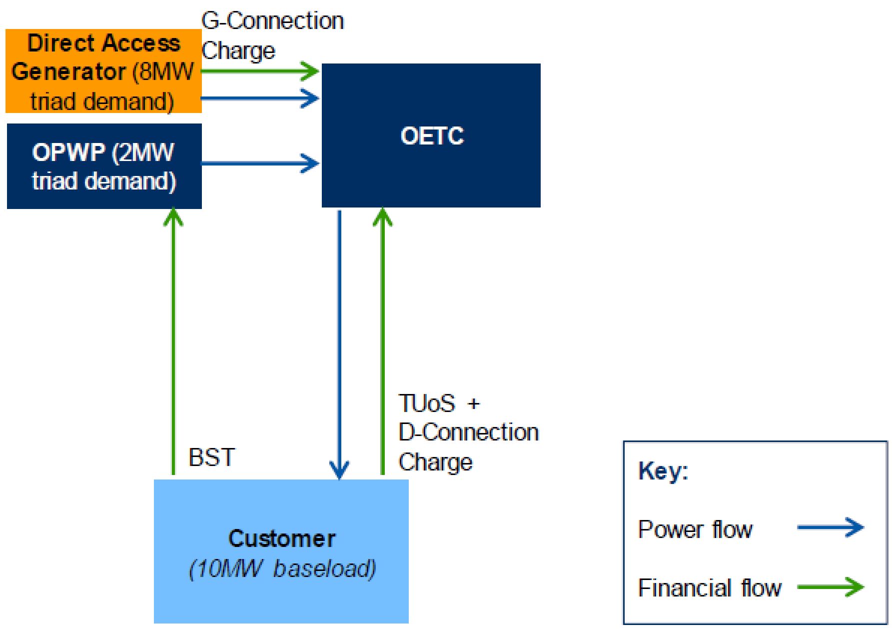
6.4 To meet the principles of cost causation set out in section 5, **we propose charging TUoS to customers served by direct access generators**. This means that the wheeling customers served by direct access generators will continue to be subject to the existing TUoS regime and will not have to pay any separate wheeling charges. Such an approach treats the customers of direct access generators equally to customers purchasing power from OPWP, because both customers impose similar costs on OETC to use the transmission system.

6.5 In addition, customers installing direct access generators connected to the transmission grid would need to pay generation connection charges as stipulated under OETC's current charging arrangements.

Illustration of payments under the proposed wheeling charges

6.6 Under the proposed wheeling arrangements, customers who previously bought all their power from OPWP will be able to purchase power (partially or entirely) from direct access generators. Figure 4 below summarises the power and financial flows between OPWP, OETC and a direct access generator for a customer which purchases some of its power via direct access, and the remainder from OPWP. For numerical simplicity, we assume that the customer demands 10 MW from the grid on average during the triad hours, of which it purchases 8 MW from the direct access generator and 2 MW from OPWP.

Figure 4- Proposed Access Charging Arrangements for Customer Partially Served by Direct Access Generator



Source: NERA illustration

6.7 Under the proposed access charging regime, customers pay TUoS on demand served by a direct access generator. Therefore, the customer in the above example is treated identically to a customer served wholly by OPWP (it pays TUoS on both the 8 MW served by the direct access generator and the 2 MW served by OPWP). The direct access generator also pays for connection to the OETC network. Table 2 below summarises the payments due to OETC.

Table 2- Proposed Payments to OETC for a Wheeling Customer

Item	Calculation
TUoS	$TUoS_t \times 10$ MW, per existing arrangements
Demand connection charge	Customer pays a demand connection charge on a bespoke basis, per existing arrangements
Generation connection charge	The direct access generator pays a demand connection charge on a bespoke basis, per existing arrangements. In addition, any generators which OPWP uses to serve demand will require to pay connection charges to OETC (note, these are not pictured in Figure 3 above)

Source: NERA analysis

Q3. Do you agree with the proposed charges charging basis for wheeling?

Standby Charge

The economic justification for the standby charge

6.8 The current TUoS charge exaggerates the incentives to self-supply at customers' sites or through private wire connections because OETC levies TUoS charges based on customers' contribution to the MTSD of the system. Consequently, customers using behind-the-meter self-generation to reduce their demand at peak times can significantly reduce their transmission costs. Customers may also be incentivised to undertake inefficient investment in private wire connections to avoid paying TUoS on power wheeled across the transmission grid.

6.9 Such an approach is not cost reflective, since it implies that the entirety of OETC's cost base is driven by MTSD, whereas, in reality, its costs are largely fixed in the short-run as demonstrated by OETC's MATR. Moreover, customers with behind-the-meter self-generation that do not consume during times of coincident peak still impose costs on OETC through their use of the transmission grid at other times. For instance, these customers still benefit from using the grid for back-up in hours when their self-generation units are not generating, as well as for other ancillary functions (e.g., for system security and stability reasons). These costs are not reflected under the current TUoS charge.

6.10 Therefore, the current TUoS charging structure sends inefficient price signals to customers with behind-the-meter self-generation, who can avoid a large proportion of transmission costs through reducing their demand during coincident peak, despite imposing costs on OETC to meet their use of transmission system at other times.

6.11 To address this, **we propose that OETC levies a standby charge on customers with behind-the-meter generation**, to ensure that self-supply customers pay a charge that reflects the cost that they impose on OETC. A standby charge is levied on an OMR per MW per year, and captures the costs that self-suppliers impose on OETC through the optionality to consume from the system during times of coincident peak, or throughout other times of the year. The proposed standby charge applies to both customers with on-site generation as well as customers with behind-the-meter generation connected through private wire.

6.12 More specifically, we propose that the standby charge recovers the fixed costs imposed on OETC to accommodate customers with behind-the-meter self-generation. This is cost-reflective because OETC incurs the fixed costs to accommodate those customers irrespective to the actual power that those customers draw from the grid during times of coincident peak. In other words, even if self-suppliers do not draw power from the grid during times of coincident peak because they self-generate, thereby avoiding TUoS charges, the customers still impose costs on OETC which are, by definition, unrelated to their actual consumption from the grid.

6.13 The fixed costs that customers with behind-the-meter self-generation impose on OETC are similar to the fixed costs imposed by other customers with similar connection sizes, but without behind-the-meter self-generation. Therefore, the standby charge should recover approximately the same fixed costs per unit of standby demand at time of coincident peak, as other customers pay per unit of demand during coincident peak through TUoS charges.

6.14 Whilst the costs that OETC incurs to accommodate a customers' connection are fixed, and invariant to the power drawn by the customer, the customer's behind-the-meter generation enables OETC to avoid the long-run marginal cost (LRMC) of serving additional demand. Therefore, customers with behind-the-meter self-generation should not have to pay the variable costs that OETC would face to accommodate flows of power, if they do not consume from the grid during times of coincident peak.

Q4. Do you agree with the proposed introduction of the standby charge introduction for introducing a standby charge? If not, please explain.

6.15 **Proposed charging basis for the standby charge**

- Customers with behind-the-meter self-generation should face a standby charge that reflects the costs that they impose on OETC. A customer that self-generates but maintains a connection to the transmission system imposes costs on OETC up to the size of its connection. This is because OETC must plan to accommodate the option for that customer to draw power from the grid at times of coincident peak up to the size of its connection, even if that customer does not actually draw any power from the transmission grid in practice. Consequently, **we propose that customers with behind-the-meter self-generation should pay a standby charge up to the size of their connection capacity with the grid (in MW).**
- However, customers may not use all of their connection capacity at times of coincident peak. A customer's connection capacity better reflects their non-coincident peak demand. In other words, connection capacity reflects a customer's expected maximum take of power at any time during the year, not just during hours of coincident peak. Therefore, levying the standby charge on connection capacity may not be cost reflective for all customers, because the maximum demand that OETC needs to plan for is demand during coincident peak.
- Consequently, we propose to tie the charge to customers' potential to demand from the grid during times of coincident peak. This is observable through metering of customers' self-generation during coincident peak, because this self-generation represents what the customers demand could be from the transmission grid if they exercised their option to use the grid instead of self-generating.
- Customers may both self-generate during times of coincident peak as well as draw power from the grid. These customers therefore contribute towards fixed costs through paying TUoS on the power they draw from the grid, in other words their "net demand". To avoid double charging these customers, we should adjust our charging basis for the standby charge for actual take from the grid during hours of coincident peak.
- Therefore, we propose to levy the charge on customers' self-generation during the triad, capped at connection capacity less net demand from the OETC grid. In other words, we propose to levy the charge on a customer with self-generation on the lesser of:

(i) its average self-generation during the triad; and

(ii) its connection capacity less net demand.

Q5. Do you agree with the proposed charging basis for the standby charge?

6.16 **Proposed calculation of the standby charge**

- OETC's fixed costs are estimated using its MAR formula. Specifically, we propose to apply the notified values in OETC's MAR formulae as a proxy for fixed costs. The formulae determining OETC's maximum allowable transmission revenue (MATR) for the MIS and DPS each contain three components: a fixed component, a component based on MTSD, and a component based on RUT.
- The fixed component of OETC's MAR provides an objective and transparent measure of OETC's fixed costs for use in calculating the standby charge. Using the same fixed costs that are recovered through TUoS ensures that we can set the standby charge to recover approximately the same fixed costs per unit of standby demand at time of coincident peak, as other customers pay per unit of demand during coincident peak through TUoS charges. This is imperative to ensure we do not inefficiently distort the incentive to install behind-the-meter self-generation rather than consume from the grid.
- In order to calculate the standby charge, we examine the maximum allowable transmission revenue in the MIS and DPS. We show the MATR for the MIS (MAMISTR) below:

$$\boxed{MAMISTR_t = (a_t + b_t * MTSD_{Mt} + c_t * RUT_{Mt}) + GCCIA_t}$$

Where:

- a_t is fixed the fixed component in year t, currently set at around 70 per cent of MAR;
- $MTSD_{Mt}$ denotes the Maximum Transmission System Demand in the MIS in year t;
- b_t denotes the weighting of MTSD in the price control calculation, which currently drives around 15 per cent of the MAMISTR;
- RUT_{Mt} denotes the aggregate of the Regulated Units Transmitted in the MIS in year t;
- c_t denotes the weighting of RUT in the price control calculation, which currently drives around 15 per cent of the MAMISTR; and
- $GCCIA_t$ denotes the charges payable to the Gulf Cooperation Council Interconnection Authority (GCCIA).

6.17 The formula for DPS is broadly the same, but it does not contain a component reflecting GCCIA annual fees. It uses notified values d_t, e_t, f_t instead of a_t, b_t, and c_t respectively.

6.18 The fixed components a_t, and d_t provide objective transparent measures of OETC's fixed costs of transmission in the MIS and DPS respectively. One could therefore apply the parameters to calculate the standby charge. We also note that there are other fixed components to OETC's MAR, which should also be reflected in the proposed standby charge (maximum allowable dispatch revenue, the correction factor, charges payable to the GCCIA, and any license fees payable to the Authority).

6.19 Thereby, to calculate standby charge per unit of transmission system demand using the following formula:

$$SBC_t = \frac{a_t + d_t + GCCIA_t + MADISR_t + LF_t - K_t - Misc\ Rev_t}{MTSD_t + SBC\ Demand_t}$$

Where:

- SBC_t is the standby charge in year t,
- $MADISR_t$ denotes the Maximum Allowed Dispatch Revenue in the year t.
- LF_t denotes OETC's share of the Licence Fee in the year t;
- K_t denotes the correction factor in the year t;
- Misc Rev_t denotes other revenues contributing to OETC's MAR in year t, excluding any standby charge revenues;
- SBC $Demand_t$ is the total number of MW across the system on which OETC levies the charge in time t; and
- All other parameters are defined as above.

6.20 In other word, the standby charge divides OETC's fixed costs across the charging base for the standby charge (SBC Demand) and the charging base for TUoS (MTSD) thereby ensuring that the fixed cost paid by each customer paying either charge is approximately the same.

6.21 The total charge payable by a customer that installs behind-the-meter self-generation can therefore be expressed as follows:

$$Total\ SBC\ Payable_t = SBC_t \times \min\left(Connection\ cap_t - Net\ demand_t,\ Self\ gen_t\right)$$

Where:

- Total SBC $Payable_t$ is the total standby charge payment for a given customer in year t;
- Connection cap_t is the capacity of the relevant customer's connection to the OETC network in year t;
- Net $demand_t$ is the customer's average net demand from the transmission system during triad hours in year t;
- Self gen_t is the customer's average self-generation during triad hours in year t; and
- All other parameters are defined as above.

6.22 **Proposed implementation of the standby charge**

- We propose that OETC sets and invoices the standby charge using a similar method to which it currently uses to set the TUoS charges. This requires that OETC forecasts SBC Demand along with MTSD and its MAR at the start of each year. It then can calculate the standby charge using the formula set out above. OETC would also update the standby charge with changes to the notified value in its MAR each year and publish the charge in December of each year for the following year.
- The standby charge are proposed to be levied on customers on an OMR per MW per year basis (possibly billed monthly), where the MW for each customer correspond to OETC's forecast of its charging basis for the standby charge which we set out above.

- The charging basis for the standby charge may change from OETC's forecasts depending on outturn customer behaviour and the actual times of coincident peak. Therefore, OETC will need to adjust the standby charge for any differences relative to its forecasts in a similar way to which it adjusts TUoS charges for actual customer behaviour during the triad hours. We propose that when actual values, as opposed to forecasts, for the charging basis and each customers' standby charge demand are available, OETC recalculates the standby charge for the year to reflect the actual values and invoices each customer accordingly. Like TUoS, the charges may be reconciled in the December invoice.

Q6. Do you agree with the proposed implementation of the standby charge? If not, please explain.

Illustration of payments under the proposed standby charge

- To illustrate the proposed standby charge, we consider a self-supply customer served by behind the meter self-generation which is connected on-site or via private wire. Such a customer avoids TUoS on its behind-the-meter generation during the triad period. However, it instead pays a standby charge on the lesser of:

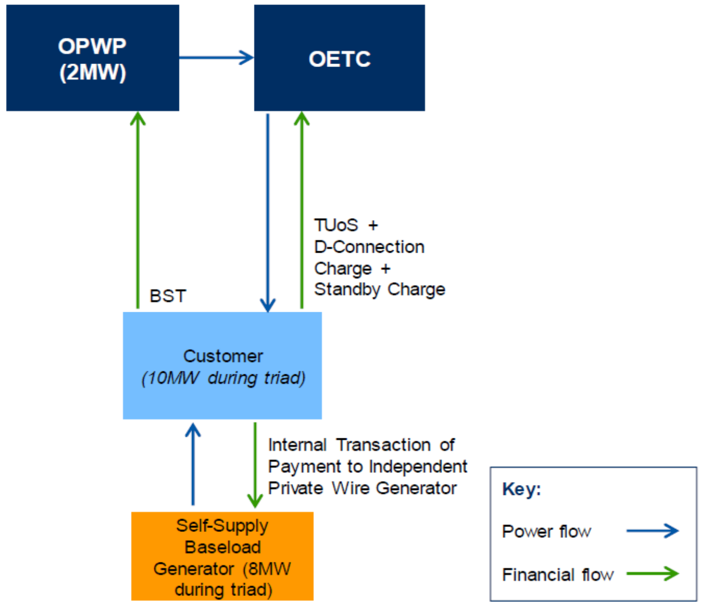
  a) its average self-generation during the triad; and

  b) its connection capacity less net demand.

- For simplicity, we assume a self-supplying customer consumes 10 MW during the triad, of which it self-supplies 8 MW, and purchases the remaining 2 MW from OPWP. We also assume that the customer has a 10 MW connection capacity. Therefore, in this example, the customer pays a standby charge on its 8 MW self-generation during the triad, and it pays TUoS on the 2 MW of power which it purchases from the grid.

- Note that the example illustrates that we do not propose to levy the standby charge on the capacity of behind the meter generation. Rather, the self-supplying customer pays a standby charge based on how much it self-generates during the triad period.

Figure 5- Proposed Access Charging Arrangements for Customers with Behind-the-Meter Self-Generation



Source: NERA illustration

Table 3- Proposed Payments to OETC for a Customer with Behind-the-Meter Self-Generation

Item	Calculation
TUoS Charge	$TUoS_t \times 2$ MW
Standby Charge	$SBC_t \times 8$ MW
Demand connection charge	Customer pays a demand connection charge on a bespoke basis, per existing arrangements
Generation connection charge	Any generators which OPWP uses to serve demand will require to pay connection charges to OETC (note, these are not pictured in Figure 5 above)

Source: NERA analysis

6.23 Table 4 below provides an illustration of the calculation of standby charge for customers with different connection capacities, self-generation, and net demand at time of coincident peak in order to demonstrate how the charging basis for the standby charge and TUoS would change accordingly.

Table 4- Schedule of TUoS and Standby Charges for Customers with Behind the Meter Generation

	Gross triad demand (MW)	Triad self-generation (MW)	Connection capacity (MW)	Net demand from grid (MW)	TUoS Payments*** (OMR)	SBC Payments*** (OMR)
	[1]	[2]	[3]	[4] = [1] - [2]	[5] = $TUoS_t$ × [4]	[6] = SBC_t × min {[2], [3] - [4]}
Connection capacity < gross triad demand						
Triad self-gen < connection capacity	10	6	8	4	4 x $TUoS_t$	4 x SBC_t
Triad self-gen = connection capacity	10	8	8	2	2 x $TUoS_t$	6 x SBC_t
Triad self-gen > connection capacity	10	10	8	0	0 x $TUoS_t$	8 x SBC_t
Connection capacity = gross triad demand						
Triad self-gen < connection capacity	10	8	10	2	2 x $TUoS_t$	8 x SBC_t
Triad self-gen = connection capacity	10	10	10	0	0 x $TUoS_t$	10 x SBC_t
Triad self-gen > connection capacity *	NA	NA	NA	NA	NA	NA
Connection capacity > gross triad demand						
Triad self-gen < connection capacity	10	6	20	4	4 x $TUoS_t$	6 x SBC_t
Triad self-gen = connection capacity **	NA	NA	NA	NA	NA	NA
Triad self-gen > connection capacity **	NA	NA	NA	NA	NA	NA

Source: NERA analysis. Notes: we include a full set of combinations for completeness, but grey out infeasible scenarios. Specifically, gross triad self-generation cannot exceed gross triad demand. Therefore, (*) when connection capacity is equal to gross triad demand, triad self-generation cannot exceed connection capacity. Similarly, (**) when connection capacity is greater than gross triad demand, triad self-generation must be less than the connection capacity.
(***) Please see Chapter 6 for illustrative values of $TUoS_t$ and SBC_t.

Q7. Do you have any comments on the proposed calculation of standby charges for customers with behind the meter generation?

Customers to whom it may be Appropriate to Grant Exemptions from TUoS

6.24 As discussed in previous sections, OETC sets TUoS to recover its cost as determined by the MAR, i.e, it sets TUoS charges to reflect the average cost of providing transmission services. This approach may deter customers who cannot cover the average cost but would pay for at least the *marginal cost* to OETC of accommodating the customers' demand. It may be deemed appropriate to exempt certain specific customers from paying the average cost OETC incurs to serve them (i.e. TUoS) and charge the marginal cost which customers impose on OETC.

Criteria for granting exemptions

6.25 We propose exempting certain types of customers from paying the average cost that OETC incurs to serve them, and instead charge those exempted customers the marginal cost of serving them. Therefore, we need to consider which customers qualify for exemption.

6.26 In considering exemption projects, these projects are likely to be large sources of electricity demand which may face economic challenge under the current transmission charging regime. Customers eligible for exemption should provide significant economic benefit to Oman so as to be accommodated into the transmission grid at marginal cost.

6.27 An important consideration is to ensure that domestic customers cannot freely switch to the exemption regime to avoid their contribution to the fixed costs of the grid, thereby increasing the average costs for remaining customers that are not exempt. It may therefore be easier to implement exemptions for separable markets (i.e., markets in which an existing domestic customer cannot interact). A good example of a separable market is the market for export, from which an existing domestic customer cannot purchase power.

6.28 A market may also be separable within the domestic market. For instance, a large investment from the Omani government into the production of hydrogen might be an example of an industry that could be considered separable from other types of domestic demand. In reality, we envisage that market separability is ensured by regulatory mechanisms. Specifically, the Sector would grant exemptions to domestic customers which they determine to be "strategic", and domestic customers without exemptions would not be able to access the exemption regime.

Thereby in summary, an exemption customer would entail the following two types of customer that could be exempt and face charges reflecting OETC's marginal cost of meeting their use of the grid. These include:

(a) Customers that export power outside of Oman, using the transmission grid; and

(b) Customers that are determined as "strategic" domestic customers on a case-by-case basis and that bring wider macro-economic benefit to Oman. We expect that the government might be more likely to deem customers as "strategic" if they are new types of domestic demand which are justifiably separable from existing domestic demand.

6.29 It is proposed that in both cases, OETC sets charges that reflect the marginal cost of incorporating the use of the grid by each customer type.

> Q8. Do you agree with the proposed criteria for granting exemptions to certain types of customers from paying the TUoS? If not, please explain.

Charge for exempted customers

6.30 We propose separate charges for exports and strategic customers that reflect the marginal cost that they impose on OETC. In particular, we distinguish between two types of customers, these include:

1) Customers that trigger additional reinforcement of OETC's network; and
2) Customers that do not trigger additional reinforcement of OETC's network.

6.31 Given the size of customers that we would expect to be required to be deemed "strategic" for Oman, we recommend that all strategic customers face the long run marginal (or incremental) cost that OETC faces to accommodate their use of the grid. We expect export customers may fall into either category depending on the nature and size of their demand, and their location on the network.

> Q9. Do you agree with the proposed basis for charges exempted customers the marginal cost to OETC of accommodating new customer demand?

6.32 Based on the above, the following charging arrangements are proposed for exempted customers:

6.33 **Exports which do not trigger investments**

- We expect that some export demand would not require any investment from OETC to serve (e.g., short-term export transactions cannot require investment since there would not be sufficient time to upgrade the grid to serve the export). In these cases, we propose to apply a volumetric charge on exporters that use the grid to facilitate the flow of export;
- This volumetric charge should be set to reflect the marginal cost that OETC incurs to accommodate additional flows of energy in its transmission grid. OETC's MAR identifies these costs explicitly. This is because OETC's MAR automatically updates with changes in the flow of energy in the transmission system across the year (RUT). The increase in MAR for every additional unit of energy that flows across the transmission system should relate to the marginal cost that OETC incurs, and therefore needs to recover, to facilitate that flow of power;

- Therefore, we propose applying the notified value applying the notified values in the MAR formulae described in Section 6.16 to infer the marginal cost to OETC incurred as a result of increased export demand. In particular, we recommend applying the notified values c_t and f_t, which are designed to reflect the extent to which OETC's costs vary with volumetric demand. For example, if a customer wants to wheel 10 MWh through the MIS for import or export, then it would pay a wheeling charge of $10 \times c_t$. We propose OETC updates the charge on exports with changes to the notified value in its MAR each year; and
- We do not propose to levy any charges on emergency and unplanned export flows, in order to avoid any implications on the security of the system.

Illustration of our proposed charging arrangements for export customers

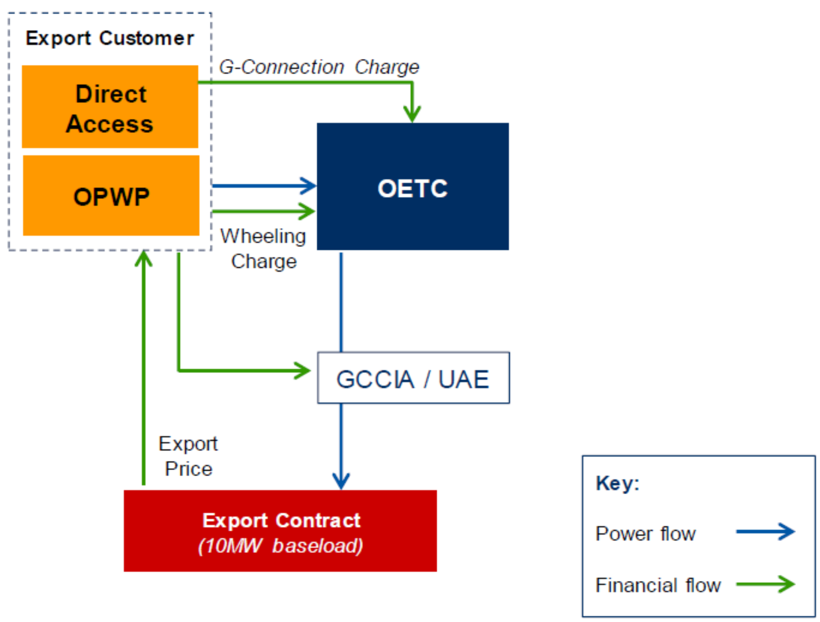
6.34 Under the proposed approach, there are two categories of export customers. These are:

1) export customers which OETC can serve without making any investments in the network who pay a volumetric charge determined by the notified values; and
2) export customers which trigger investment by OETC, and therefore instead pay the long run marginal cost that OETC incurs to accommodate their use of the grid.

6.35 In addition, if a direct access generator facilitates the export contract, it will pay a generation connection charge. OPWP and generator(s), where applicable will also need to pay relevant wheeling charges to external parties (i.e., to use the UAE and/or GCCIA networks).

6.36 Figure 6 summarises the relevant power and financial flows for an exporter.

Figure 6- Proposed Access Charging Arrangements for Export Customers



Source: NERA illustration

For the purpose of illustration, we assume that the exporter serves a 10 MW baseload customer. However, the charge would only apply to the energy taken from the grid (i.e., a customer with a capacity of 10 MW which does not take 10 MW in every hour would pay less to reflect a lower volumetric demand). Figure 6 summarises the relevant power and financial flows for an exporter.

6.37 Figure 6 above presents an illustration of the relevant power and financial flows for an exporter.

6.38 Table 5 below summarises the payments due to OETC.

Table 5- Proposed Payments to OETC for an Exporter

Item	Calculation
TUoS Charge	The customer is exempt from paying TUoS
Wheeling charge	If OETC can serve export flows without investments, the wheeling charge is set as follows, depending on whether the demand is in the MIS or in DPS: ▪ Energy charge (MIS): $c_t \times 10\text{ MW} \times 8760\ hours$ ▪ Energy charge (DPS): $f_t \times 10\text{ MW} \times 8760\ hours$ **OR** If OETC must invest in the network to serve the export flows, the wheeling charge is: ▪ *levelised fixed costs of expansion to serve new demand* (only applicable if flows trigger network expansion.
Demand connection charge	Not Applicable.
Generation connection charge	Direct access generators pay a generation connection charge on a bespoke basis, per existing arrangements. In addition, any generators which OPWP uses to serve demand will require to pay connection charges to OETC (note, these are not pictured above).
External wheeling charges	OPWP and direct access generator(s) serving the export demand need to pay relevant wheeling charges to external parties (e.g., TRANSCO in the UAE and/or the GCCIA).

Source: NERA analysis

6.39 Exports that <u>do</u> trigger investment and strategic customers

6.40 Other export customers and strategic customers, which are likely to be large, will require that OETC reinforces its network to accommodate their use of the grid.

6.41 We propose that, in these cases, customers cover the Long Run Marginal Cost (LRMC) imposed on OETC to facilitate their use of the transmission network. This is a cost reflective charge that ensures that OETC can recover its costs of accommodating the customer, thereby meeting our evaluation criteria for the design of charges.

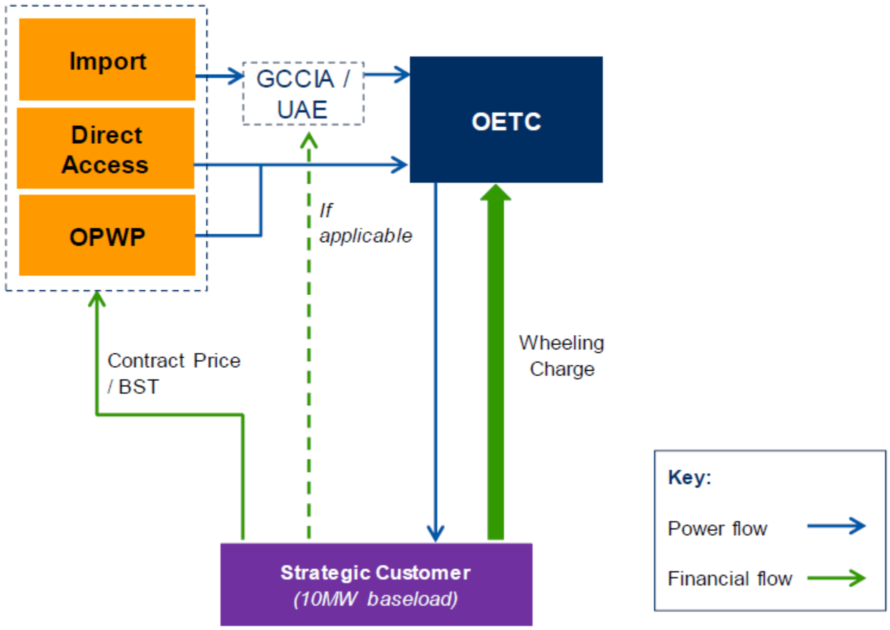
6.42 We expect that these customers would be sufficiently large in terms of additional load on the system that OPWP and OETC would conduct system studies and associated analysis around integrating the customer to the grid (e.g., by modelling scenarios with and without the additional demand). Through the analysis, we expect that OETC can identify additional investment costs (Capex and Opex) associated with serving exempted customers.

6.43 Having identified the cost, we recommend that OETC recovers investment costs by charging customers the levelized fixed costs of investment required to serve their new demand, plus any associated Opex.

6.44 Customers with exemptions from TUoS ("exemption customers") may receive significant additional incentives to demand electricity from the transmission network compared with conventional customers, because they avoid paying the average cost of the transmission network, and instead pay their marginal cost. However, we note that we do not recommend providing further incentives for exemption customers through discounting transmission charges below the LRMC that OETC incurs to integrate the customer.

6.45 We note here that demand for imports into Oman is captured under the internal system demand. Therefore, customers served by imports continue to pay TUoS. The exception to this rule is if a strategic customer imports, in which case we propose that its payments to OETC are governed by the strategic customer exemption outlined above.

Figure 7- Proposed Access Charging Arrangements for Strategic Customers



Source: NERA illustration

Figure 7 above summarises the relevant power and financial flows for the strategic customer.

For simplicity, we assume the strategic customer is a 10 MW baseload customer. However, the charge would only apply to the energy taken from the grid (i.e., a strategic customer with a capacity of 10 MW which does not take 10 MW in every hour would pay less to reflect a lower volumetric demand).

Table 6 below summarises the payments due to OETC.

Table 6- Proposed Payments to OETC for Strategic Customer

Item	Calculation
TUoS Charge	The customer is exempt from paying TUoS
Wheeling charge	*Customer pays LRMC = levelized fixed costs of expansion to serve new demand* (only applicable if flows trigger network expansion.
Demand connection charge	Customer pays a demand connection charge on a bespoke basis, per existing arrangements
Generation connection charge	Direct access generators pay a generation connection charge on a bespoke basis, per existing arrangements. In addition, any generators which OPWP uses to serve demand will require to pay connection charges to OETC (note, these are not pictured in Figure 5.4 above).
External wheeling charges	The generator(s) serving the exempted customer need to pay relevant wheeling charges to external parties (e.g., TRANSCO in the UAE and/or the GCCIA).

Source: NERA analysis

6.46 Strategic customers may source their power from OPWP, a direct access generator or via import. Under our proposed approach, strategic customers only pay the marginal cost of serving their demand. As explained previously, strategic customers must cover the levelized fixed cost of any investments required by OETC to facilitate the additional demand.

6.47 As above, if a direct access generator serves the strategic customer, it will also pay a generation connection charge. The generator(s) serving the strategic customer may also need to pay additional wheeling charges to external parties to use the UAE and/or the Gulf Cooperation Council Interconnection Authority (GCCIA) networks.

Q10. Do you agree with the definition and proposed charging arrangements for exempted customers (exports that do not trigger investment and strategic customers)?

Assessment of proposed methodology against the economic principles

6.48 The following section sets out how the proposed methodology is assessed against the economic principles set out in section 5.2.

Criteria	Assessment against criteria
Price Signal	The proposed access charging regime is grounded in principles of cost-reflectivity which ensure that the price signals sent by the charges encourage more efficient behaviour by customers. Specifically: • The proposed wheeling charge reflects the costs that wheeling imposes on OETC, which is the same as the cost imposed by a customer consuming from the grid and reflected in the TUoS charge. • The proposed access charging regime improves on the existing charging structure by introducing a standby charge thereby, sending more efficient price signals over the value of self-generation and private wire in Oman. Specifically, it ensures that customers with behind-the-meter continue to contribute towards the costs that they impose on OETC's network, specifically the fixed costs of the network. However, the standby charge does offer a reduction on TUoS to reflect OETC's avoided marginal cost of serving the demand which is met through self-generation. • This approach also does not deter separable new types of electricity demand (such as exports and strategic industries) by pricing at marginal cost for specific exempted customers.
Cost recovery	Under the proposed approach, OETC will continue to recover its MAR. Additional revenue recovered through standby charges can be netted off OETC's MAR to ensure it does not over-recover in comparison to its revenue requirement.

	For customers that are exempt from paying TUoS, we propose charges that recover OETC's marginal cost of serving those customers, thereby also ensuring cost recovery.
Fairness & Equity	The proposed access charges are cost-reflective and therefore does not inequitably distinguish different types of customers. In particular, the charge does not subsidise or discourage self-generation over purchasing power from the grid explicitly, but instead sends more efficient price signals over the costs that OETC avoids due to self-generation to customers. Moreover, it treats OPWP and other customers equally, as all customers pay the costs that they impose on OETC.
Stability & Predictability	The proposed charges are linked to the notified values in OETC's MAR formula. The notified values are stable and predictable because they are set in advance for a whole regulatory period. To the extent that our proposed charges change between years, these changes reflect corresponding changes in OETC's costs of providing transmission.
Practicality	The proposed access charge is practical to implement. It is based on notified values which are already known and understood by OETC. Moreover, they are also simple to apply formulaically, such that customers can easily understand the charging arrangements. Exempted customers are subject to somewhat more complex bespoke arrangements, which are deemed necessary to avoid the inefficiency associated with average cost pricing towards separable new electricity user markets.

Q11. Do you have any views about how the proposed access charges are assessed against the five criteria?

7. Interactions with Existing Regulatory Regime

7.1 The following Section sets out the interactions of the proposed access charging methodology with the current regulatory regime in Oman.

7.2 The first section aims to describe how we anticipate revenues under the access charging regime contribute to OETC's MAR and the implications for calculating TUoS; and the second section will outline and illustrate our financial modelling to estimate values of TUoS and the standby charge under our proposed regime.

Implications of the Access Charging Regime for OETC's MAR and TUoS

7.3 Under the proposed access charging methodology, customers will continue to pay TUoS as normal, which will contribute to OETC's MAR as per the existing regime. However, there are new charges which OETC will levy on its customers: standby charges on customers with behind-the-meter self-generation, revenues from export customers, and revenues from strategic customers.

7.4 The standby charge would constitute another regulated income, and OETC therefore ought to also net standby charge revenues from the MAR before calculating TUoS charges on the residual to ensure consistency with the current approach to calculating TUoS.

7.5 Therefore, we propose that any revenues from standby charges are included in the "other revenues" term of OETC's MAR.

$$\boxed{MAR_t = MATR_t + MADISR_t + LF_t - K_t - Other\ Revenues_t}$$

Where:

- MAR_t denotes the Maximum Allowed Revenue in the year t.
- $MATR_t$ denotes the Maximum Allowed Transmission Revenue in the year t.
- $MADISR_t$ denotes the Maximum Allowed Dispatch Revenue in the year t.
- LF_t denotes OETC's share of the Licence Fee in the year t.
- K_t denotes the correction factor in the year t.
- Other $Revenues_t$ denotes other regulated income received by OETC in the year t, including any standby charge revenues.

7.6 However, it is proposed that revenues from customers with exemptions (i.e., export customers and strategic customers) are recovered in the same way as transmission connection charges. Specifically, we propose that OETC recovers the costs associated with assets that it builds to facilitate demand from export or strategic customers separately from the MAR. The costs of these investments will be recovered through charges on the customers that trigger the need for reinforcement under our proposed charging methodology.

7.7 Equally, we propose that revenues from volumetric charges levied on export customers that do not trigger reinforcement are also maintained outside of the MAR. This is because it would mean RUT will need to be redefined in order to be included in the MAR. In both cases, the revenue from these sales would exactly equal the marginal cost incurred by OETC to facilitate them. Therefore, for simplicity and to avoid changes to the definition of OETC's MAR, we propose that the revenues from export customers be treated outside of MAR.

Q12. Do you agree with the proposal that revenues from exempted customers should have the same treatment as transmission connection charges i.e they are recovered separately from OETC's MAR?

Financial Modelling Results

7.8 In the following section, four illustrative examples are presented to demonstrate how the levels of TUoS and standby charge vary with standby charge demand and revenues from exemption customers:

- Case 1: Zero standby demand in both 2019 and 2020 and no exemption customers.
- Case 2: Standby charge demand is 100 MW in both 2019 and 2020, and no exemption customers.
- Case 3: Zero standby charge demand in both 2019 and 2020. However, in both 2019 and 2020, we assume there is 5,000 MWh of demand for exporting from the MIS, and 500 MWh of demand for exporting in DPS. The exports do not trigger any investments.
- Case 4: Zero standby charge demand in both 2019 and 2020. However, a strategic customer implements a project costing OMR 17 million in Capex and OMR 1.7 million per annum in fixed Opex.

7.9 **Case 1: No revenues from standby charge or exemption customers**

In Case 1, we assume that there are no exemption customers nor revenues from standby charges. In the absence of any standby charge demand or revenues from exemption customers, Case 1 is the same as the status quo in Oman.

Table 7- Case 1 Standby Charge Calculation

		Unit	2019	2020
Demand				
MTSD	*[1]*	*MW*	6,669	7,013
SBC Demand	*[2]*	*MW*	0	0
Fixed Costs				
a_t		OMR	4,139,851	4,225,151
d_t		OMR	70,491,766	71,944,222
$MADISR_t$		OMR	2,521,142	2,141,335
LF_t		OMR	673,560	549,076
K_t		OMR	1,376,676	2,308,261
$GCCIA_t$		OMR	881,565	1,457,310
Misc Rev		OMR	260,000	200,000
Total Fixed Costs	[3]	**OMR**	**80,344,561**	**82,825,356**
SBC_t	*[3] / ([1] + [2])*	***OMR per MW***	**12,048**	**11,811**

Source: NERA analysis of OETC data

The standby charge does not generate any revenue as there is no standby charge demand on which to levy the charge. Therefore, OETC's recovers its entire MAR via TUoS and its Other Revenues. Table 8 summarises financial modelling results for Case 1.

Table 8- Case 1 Financial Modelling Summary

	Unit	2019	2020
Demand			
MTSD	*MW*	**6,669**	**7,013**
SBC Demand	*MW*	**0**	**0**
SBC_t	*OMR per MW*	**12,048**	**11,811**
Revenue Calculations			
Total MAR	*OMR*	107,264,653	112,293,004
Revenue from Exemption Customers	*OMR*	0	0
SBC Revenue	*OMR*	0	0
Total Other Revenue	*OMR*	260,000	200,000
Net MAR to be invoiced for TUoS	*OMR*	107,004,653	112,093,004
TUoS Calculations			
$TUoS_t$	*OMR/MW*	16,046	15,984
TUoS Revenue	*OMR*	107,004,653	112,093,004
Total revenue recovered	*OMR*	107,264,653	112,293,004

Source: NERA analysis of OETC data

7.10 **Case 2: Revenues from standby charge but no revenue from exemption customers**

In Case 2, we assume that there is 100 MW of standby charge demand in both 2019 and 2020. The increased standby charge demand results in a marginal decrease in the calculated standby charge, reflecting the fact that the fixed costs of the network are allocated across a larger demand base. Table 9 below illustrates the calculation of the standby charge according to the formula set out in Section 6.16.

Table 9- Case 2 Standby Charge Calculation

		Unit	2019	2020
Demand				
MTSD	*[1]*	*MW*	6,669	7,013
SBC Demand	*[2]*	*MW*	100	100
Fixed Costs				
a_t		OMR	4,139,851	4,225,151
d_t		OMR	70,491,766	71,944,222
$MADISR_t$		OMR	2,521,142	2,141,335
LF_t		OMR	673,560	549,076
K_t		OMR	1,376,676	2,308,261
$GCCIA_t$		OMR	881,565	1,457,310
Misc Rev		OMR	260,000	200,000
Total Fixed Costs	[3]	**OMR**	**80,344,561**	**82,825,356**
SBC_t	*[3] / ([1] + [2])*	***OMR per MW***	**11,870**	**11,645**

Source: NERA analysis of OETC data

In this example, standby charge revenues are around OMR 1.2 million in 2019 and 2020, which increase the total Other Revenues which OETC collects. TUoS therefore declines marginally to ensure that OETC recovers its MAR, accounting for its increased Other Revenues. Table 10 below summarises financial modelling results for Case 2.

Table 10- Case 2 Financial Modelling Summary

	Unit	2019	2020
Demand			
MTSD	*MW*	**6,669**	**7,013**
SBC Demand	*MW*	**100**	**100**
SBC_t	*OMR/MW*	**11,870**	**11,645**
Revenue Calculations			
Total MAR	*OMR*	107,264,653	112,293,004
Revenue from Exemption Customers	*OMR*	0	0
SBC Revenue	*OMR*	1,187,026	1,164,466
Total Other Revenue	*OMR*	1,447,026	1,364,466
Net MAR to be invoiced for TUoS	*OMR*	105,817,627	110,928,538
TUoS Calculations			
$TUoS_t$	*OMR/MW*	15,868	15,818
TUoS Revenue	*OMR*	105,817,627	110,928,538
Total revenue recovered	*OMR*	107,264,653	112,293,004

Source: NERA analysis of OETC data

7.11 **Case 3: No revenues from standby charge, but revenue from exports which do not trigger investments**

7.12 In Case 3, we assume zero standby charge demand, but instead assume that OETC serves exemption customers. Specifically, we assume that in both 2019 and 2020 there is 5,000 MWh of demand for exporting from the MIS, and 500 MWh of demand for exporting in DPS.

7.13 We note that the following example only includes revenues from exports which we assume do not trigger reinforcements. We do not include wheeling charges for other exemption customers (i.e., strategic customers and exports triggering reinforcements), which would be set on a project-by-project basis reflecting the specific long-run marginal cost of the exempted project (see Case 4 for an example).

7.14 As outlined in Section 7.3, we propose that OETC collects all revenues from exemption customers outside of the MAR. Therefore, we do not show calculations of the standby charge, TUoS and the MAR, since these are identical as under Case 1 (see Table 7 and Table 8). Instead, we show the calculation of revenues from exemption customers (specifically, from exports which do not trigger investments) in Table 11 below.

Table 11- Case 3 Exemption Customer Revenues

		Unit	2019	2020
Volume Demanded				
Volume Demanded (MIS)	[1]	*MWh*	5,000	5,000
Volume Demanded (DPS)	[2]	*MWh*	500	500
Applying Notified Values				
Notional Value Energy (MIS)	[3]	*OMR per MWh*	0.381	0.389
Notional Value Energy (DPS)	[4]	*OMR per MWh*	0.216	0.221
Energy Cost (MIS)	[5] = [1]×[3]	*OMR*	1,906	1,945
Energy Cost (DPS)	[6] = [2]×[4]	*OMR*	108	110
Revenue from Exemption Customers	[7] = [5]+[6]	*OMR*	2,014	2,056

Source: NERA analysis of OETC data

7.15 **Case 4: No revenues from standby charge, but revenue from strategic customer**

In Case 4, we again assume zero standby charge demand and that OETC serves exemption customers. Specifically, we now assume that OETC serves one strategic customer which implements a project costing OMR 17 million in Capex OMR 1.7 million per annum in Opex.

As explained above, we propose that OETC collects all revenues from exemption customers outside of the MAR. Therefore, we do not show calculations of the standby charge, TUoS and the MAR, since these are identical as under Case 1 (see Table 7 and Table 8). Instead, we present the calculation of revenues from the example strategic customer below.

As explained above, we propose to calculate wheeling charges for strategic customers (and for exports which trigger investments) on a case-by-case basis, such that the wheeling charges reflect the long-run investment costs associated with serving the relevant customer's load. We therefore calculate the total wheeling charge for the example strategic customer as the sum of the equivalent annual Capex cost and any fixed Opex costs.

Table 12- Case 4 Exemption Customer Revenues

Item	Unit	Value	Source
Parameters			
Size	MW	1,400	OETC
Capex	OMR million	17	OETC
Opex	OMR million	1.7	OETC
Assumed asset life	Year	20	NERA Assumption[1]
WACC	%	4.6%	APSR[2]
Equivalent Annual Cost Calculation			
Capex	OMR million	1.32	NERA Calculation
Opex	OMR million	1.70	NERA Calculation
Total	OMR million	3.02	NERA Calculation
Wheeling Charge	OMR / MW	2,156	NERA Calculation

Source: NERA analysis of cost information as provided by OETC. (1) APSR (then AER), (25 October 2018), T&D-PCR5: Initial Proposals, Table 9-10. Notes: we assume that capex is spent overnight at project commissioning, and that opex remains fixed in real terms over the duration of the project lifetime.

Q13. Do you agree with the proposed charging mechanisms for the four examples provided above? Please provide any comments you may have on the examples provided above.

8. Further Developments

8.1 The document presents the Authority's proposal and recommendation for the introduction of an access charging regime. As part of the Sector's development, the sector will undertake a broader set of reviews that will encompass the current TUoS, BST as well as the costs related to ancillary services and balancing the transmission system. These reviews are designed to ensure that the charging methodologies in place appropriately capture the ongoing and expected developments in the electricity sector.

8.2 The Authority welcomes your views and comments on this access charge consultation document by 19 May 2022.

9. Summary of questions

Section	Subject	Questions
5.24.22	Illustration of Current Transmission Charges	Q1. Do you agree with the proposed charging basis for wheeling charges?
5.2	Criteria for efficient tariff design	Q2. Do you agree with the above criteria and principles for the development of access charges? In your view, should any other criteria/principles be considered?
6.7	Illustration of payments under the proposed wheeling charges	Q3. Do you agree with the proposed charges charging basis for wheeling?
6.8	Standby Charge - *The economic justification for the standby charge*	Q4. Do you agree with the proposed introduction of the standby charge introduction for introducing a standby charge? If not, please explain.
6.15	Standby Charge - Proposed charging basis for the standby charge	Q5. Do you agree with the proposed charging basis for the standby charge?
6.22	Standby Charge - Proposed implementation of the standby charge	Q6. Do you agree with the proposed implementation of the standby charge? If not, please explain.
6.23	Standby Charge - Illustration of payments under the proposed standby charge	Q7. Do you have any comments on the proposed calculation of standby charges for customers with behind the meter generation?
6.25	Criteria for granting exemptions	Q8. Do you agree with the proposed criteria for granting exemptions to certain types of customers from paying the TUoS? If not, please explain.
6.30	Charge for exempted customers	Q9. Do you agree with the proposed basis for charges exempted customers the marginal cost to OETC of accommodating new customer demand?

6.33	Exports which do not trigger investments	Q10. Do you agree with the definition and proposed charging arrangements for exempted customers (exports that do not trigger investment and strategic customers)?
6.48	Assessment of proposed methodology against the economic principles	Q11. Do you have any views about how the proposed access charges are assessed against the five criteria?
7.7	Implications of the Access Charging Regime for OETC's MAR and TUoS	Q12. Do you agree with the proposal that revenues from exempted customers should have the same treatment as transmission connection charges i.e they are recovered separately from OETC's MAR?
7.8	Financial Modelling Results	Q13. Do you agree with the proposed charging mechanisms for the four examples provided above? Please provide any comments you may have on the examples provided above.

Annex 1

1. Technical Considerations of the Proposed Access Charge

1.1 The following Section summarises the key technical considerations around the proposed access charge.

Metering Arrangements

- The proposed access charging regime involves implementation of a standby charge, levied on the lesser of (a) the customer's average self-generation during the triad; and (b) the customer's connection capacity less net demand. To adequately capture demand during triad periods for connections possessing local site generation behind-the-meter, it is necessary to ascertain local demand accurately with a level of precision that could be reasonably expected for transactional based calculations.

- The implementation of the proposed regime requires some modification of the current metering arrangements. We recognise that such modifications are not directly aligned with the current regulatory requirements, so there may be a need to re-evaluate elements of the Grid Code. Some key considerations associated with the potential changes in metering arrangements.

- The Oman Metering and Data Exchange Code (MDEC) prescribes arrangements and technical characteristics around metering. Until today, internal (and potentially auxiliary) demand within a facility where both generation and demand exists has not needed to be metered to disaggregate the amount of demand offset by local generation. Therefore, only net demand/supply is visible at the Delivery Point, as set out within the associated parties' connection agreement. This data must be connectable to and interrogable by the OETC Load Dispatch Centre (LDC). Equipment at the LDC will read the Meter Data at the specified time and frequency.

- We recognise that MDEC also specifies obligations around metering location in relation to outstation. If additional meters or replacement of existing meters to more accurate revenue-based metering is necessary, then OETC would need to be able to interrogate these values. We note that the development of operational facilities did not occur with this obligation in mind. Therefore, it may be necessary to ensure access to this additional metering. For existing facilities, it may be necessary to take a measured approach, whereby associated metering data internal to the site can be extracted either by site personnel, or OETC at a pre-arranged point in time subsequent to triad hours. One could make the process subject to audit and cross verification if deemed necessary.

Scaling up Bilateral Arrangements

1.2 The concept of wheeling generally implies that electricity generated at one site will find its way to the site of the receiving customer. Once other consumers and generators are connected to the network, the flow of electricity becomes more complex, and as the generation mix changes and the load profile of the network varies, it is very difficult to determine the flow of power in the network from the generator to the intended load, or where power for a contracted load will come from. In reality, a generator supplies power to the grid and the customer draws power from the grid, and there is no fixed power flow between them.

1.3 We recognise that introducing wheeling may impact the transmission network. We outline below some of the potential consequences associated with changing the generation location and associated transmission as wheeling escalates.

(1) The historical utilisation of transmission assets may marginally change as power is wheeled. Specifically, the design of the existing infrastructure did not explicitly anticipate wheeling, so there may be changes in equipment loading and perhaps minor changes in transmission losses against historical norms. However, there would also be net benefits to system losses associated with exporting power internationally under low load conditions.

(2) The voltage profile could feasibly change, depending on whether specific spot loads are locally serviced or supplied by remote renewables in other locations. Although, whether this would step profiles outside of Grid Code limits is speculative.

(3) We would note that it may be necessary to re-evaluate the infeed loss risk depending on the potential levels of import that could conceivably occur were such a mechanism put in place. A potential unintended consequence could be less available reactive support from local generators unless alternatively procured.

Dispatch

1.4 We note that under the proposed arrangements, OETC requires additional documentation on a daily basis from companies who expect to be wheeling power. Specifically, OETC requires the following information:

1.5 Companies wheeling power from generation to demand using the transmission system should indicate:

a) how much demand they will supply on half-hourly basis;

b) generation production on a half-hourly basis; and

c) Companies exporting power to the GCCIA should provide data on exports to the GCCIA on a half hourly basis.

1.6 We would recommend that the provision of the above data roughly follows the below schedule:

- Companies wheeling power should provide details of wheeling contracts for the relevant day on a day-ahead basis, at an agreed time (generally before 10:00);
- The wheeling companies then issue details of forecast wheeling to OETC before gate closure; and finally

- For settlement purposes, wheeling parties should provide actual metering information for each wheeling contract and each half-hour period, within an agreed timescale (e.g., within 24 hours).

1.7 Whilst the proposed access charging regime imposes some additional data requirements, we consider that the existing dispatch procedures are fit for purpose.

Conclusions on Technical Considerations

1.8 We note that one would need to put in place mechanisms to meter self-generation, and such mechanisms may require some modifications to the Grid Code. However, we do not anticipate significant technical challenges to doing so, in particular for customers with self-generation for whom the new metering arrangements are relevant. We also note that, whilst the proposed access charging regime imposes some additional data requirements, we consider that the existing dispatch procedures are fit for purpose.

1.9 We have considered technical consequences associated with scaling up wheeling on the network. We anticipate that there may be small changes to the utilisation of transmission assets, the voltage profile on the network. Should large scale wheeling occur whereby Oman receives power in excess of the current infeed loss risk, there may be a need to need to consider the impacts of this. However, we think it is unlikely that any of these considerations poses a significant technical risk to the OETC network.