Oman Power and Water Procurement Co. (SAOC)

Bulk Supply Tariffs for 2019

Tariff Methodology

Summary

This document provides an overview of the methods used to prepare the Bulk Supply Tariffs (BSTs) for electricity and water as they are applied to the Main Interconnected System (MIS) and Dhofar.

OPWP conducted a review of the BST methodology in 2011, which the AER approved in February 2012. Minor modifications to the methodology have been approved by the AER and implemented in subsequent BSTs, with updates to this document. The methodology used for the 2019 BSTs is unchanged in principle, but introduces a Tariff Balancing Charge toward reducing year-to-year fluctuations in the tariffs that are not caused by changes in underlying costs in the current year. This change is intended to provide a clearer price signal to consumers.

The principles of the BST methodology, with respect to the tariff level, structure, and billing determinants, are described as follows:

1. **Level.** The level of both electricity and water BSTs should be set to the relevant revenue requirement. The revenue requirement is defined as the allowed financial costs allocated to the relevant sector and business;

2. **Structure.** The structure of the BSTs should be based on underlying marginal costs, and scaled appropriately to a level that will recover the revenue requirement. Conclusions specific to the electricity and water sectors are described as follows:

    a. Electricity. The structure is based on underlying short-run marginal economic costs. This approach best promotes allocative efficiency, recognising that electricity consumption outside the peak demand periods is unlikely to require new capacity. Both short-run marginal capacity costs and short-run marginal energy costs are scaled by a common factor to reach the electricity revenue requirement, in order to preserve the price signal.

    b. Water. The structure is based on long-run marginal economic costs. Considering that incremental water demand at any time of the year requires new capacity, unlike electricity, this approach best promotes allocative efficiency in the water sector. Separate scaling factors are determined for the fixed and variable components: the fixed component of long-run marginal costs are scaled to reach the fixed component of the water revenue requirement, and the variable component of long-run marginal costs are scaled separately to recover the variable component of the water revenue requirement. Other scaling approaches would expose OPWP to potentially large mismatches between its revenues and its costs given the difficulties with forecasting water sales volumes, and the large difference between variable economic cost and variable financial costs faced by OPWP.

3. **Billing Determinants.** The current billing determinants remain appropriate for both electricity and water.

Introduction

This document summarises the key steps in the methodology used to develop the electricity and water BSTs for 2019. The description of these steps examines first the electricity BST methodology, then the water BST methodology, and finally, the allocation of joint costs (in the case of IPWPs) to the electricity and water sectors respectively. The electricity BST for 2019 are presented in annex to the document.

The guiding principles are that:

a) Tariff **levels** should be based on financial costs.[1] While efficiency arguments would suggest tariff levels should be based on the economic costs, this is considered unacceptable as it would result in a large over-recovery of financial costs (i.e., exceeding the Maximum Allowed Revenue in the OPWP licence).

b) Tariff **structure** should be based on the underlying structure of economic marginal costs. Economic efficiency will be encouraged by reflecting the underlying structure of marginal costs where reasonably practical, for example in the choice of rate bands for electricity.

OPWP uses a number of models to develop the BSTs, comprising:

a) The **Demand Forecast** model: an in-house Excel model that takes input on historical electricity and water demand and projections of customer load growth to develop a forecast of electricity and water demand, which is used as input to the Power System Simulation model.

b) The **Power System Simulation** model: a proprietary generation investment planning and dispatch model, that takes input data on demand, generation and fuel prices (in either economic or financial prices), and power system operational characteristics to simulate the hourly dispatch of the power system and simultaneously estimate hourly short-run marginal costs (SRMCs), disaggregated into short-run marginal capacity costs (SRMCCs) and short-run marginal energy costs (SRMECs), and fuel costs.

c) The **Revenue Requirements** model: an in-house Excel model that takes input data on OPWP purchase costs, OPWP-own costs and other allowed costs and derives revenue to be recovered from the electricity and water BSTs for the Main Interconnected System ("MIS") and the Dhofar Power System ("DPS") (previously known as the Salalah System).

d) The **Electricity BST** model: an in-house Excel model that takes input data on hourly SRMCCs and SRMECs from the Power System Simulation model and the electricity revenue requirement from the Revenue Requirements model together with a user selection of rate bands and scaling approach to derive the electricity BST for a particular system.

e) The **water BST** model: an in-house Excel model that takes input data on costs of water production from a recent engineering report, electricity costs from the electricity BST model and the water revenue requirement from the Revenue Requirements model

[1] Financial costs in this context correspond to OPWP's actual "out-of-pocket" costs to supply electricity. This is relevant in particular to the actual cost of natural gas used for electricity generation as supplied by the Ministry of Oil and Gas. Economic costs in this context correspond in contrast to the "opportunity cost" of natural gas, evaluated at international prices.

together with a user selection of scaling approach to derive the water BST for a particular system.

The models place certain practical limitations on the methodologies. The Power System Simulation model is an hourly unit-commitment model that meets international standards, yet its flexibility is also somewhat limited as it needs significant user inputs to model combinations of outages of equipment at the combined cycle plants and electricity production at IWPPs and to meet the security standard in terms of loss-of-load-hours (LOLH). The in-house models were also developed to provide flexibility, yet there are implicit limitations in their design as well as explicit limitations such as on the number of rate bands, choice of hours in each rate band and the selection of scaling approach.

Electricity BST Methodology

The principles used to develop the electricity BST and the key steps in the methodology are described below, dealing firstly with structure and secondly with level and scaling. Figures 1 and 2 show the main steps in the development of the electricity BST.

Figure 1 : Steps to determine the structure of the electricity BST

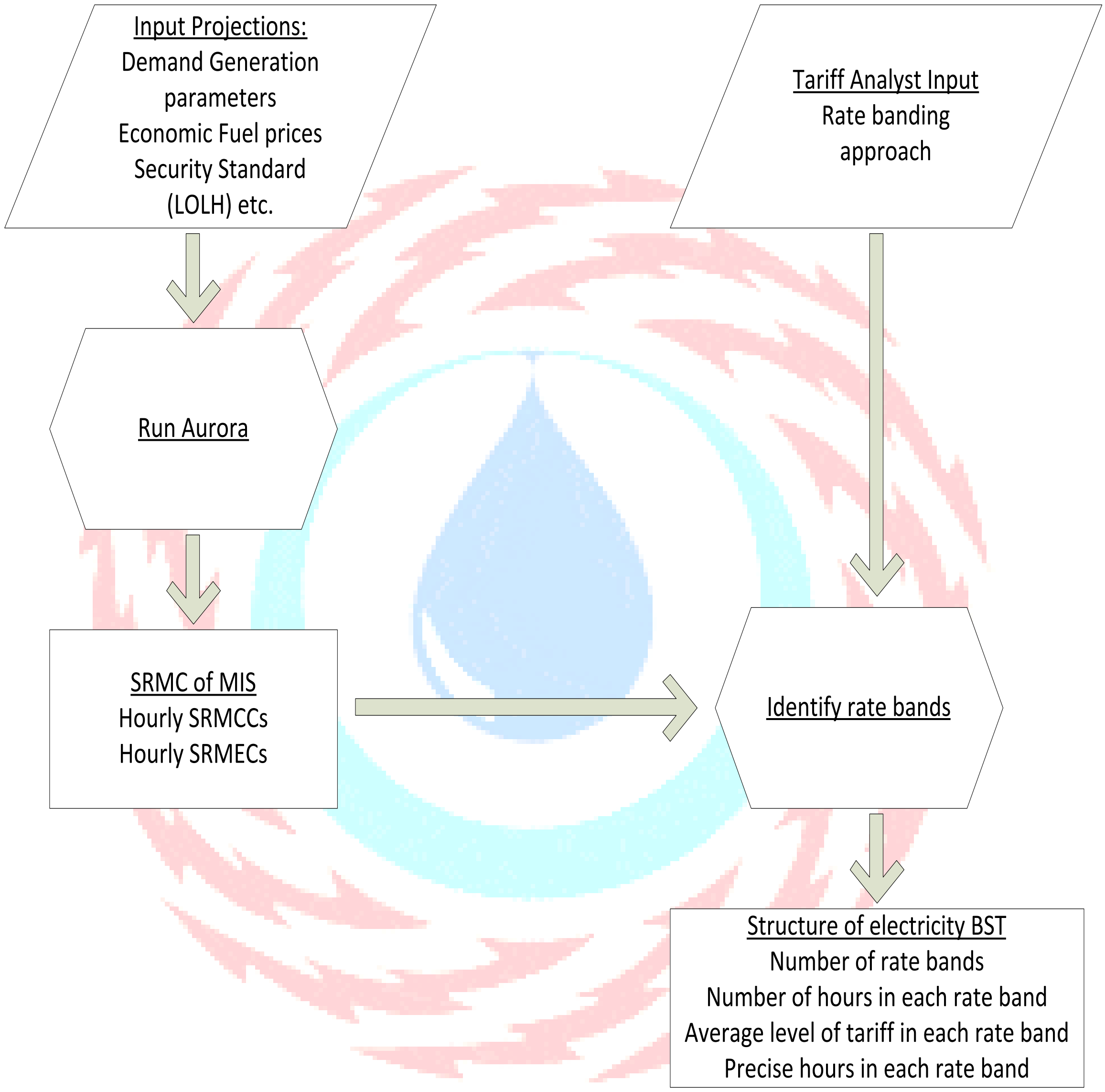
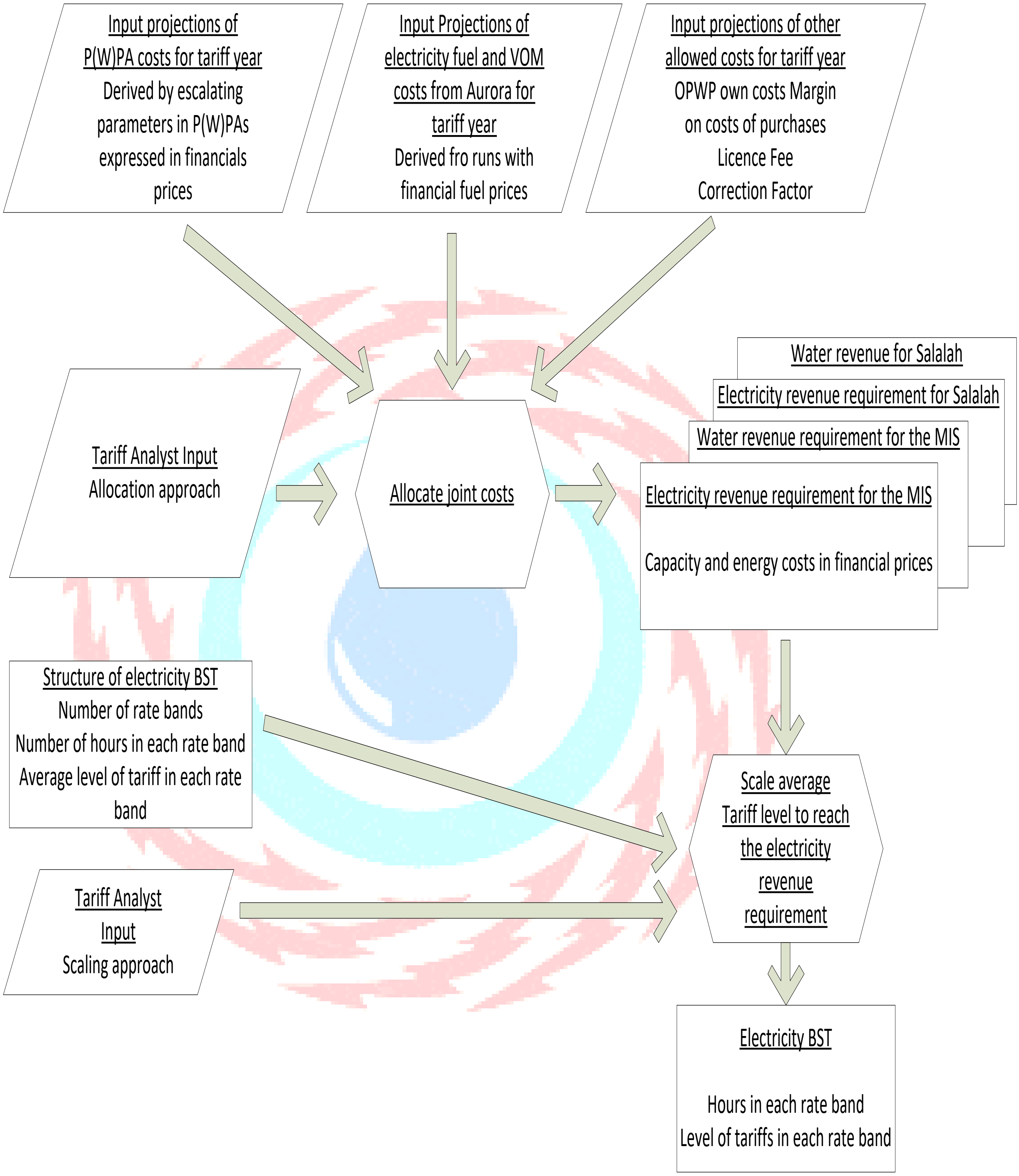


Figure 2 : Steps to determine the level of the electricity BST



Principles

The following five principles have guided the development of the electricity BST:

a) The structure of the BST is set to reflect short run marginal economic costs in order to promote allocative efficiency.

b) The level of the BST is set to achieve the combined electricity revenue requirement of the MIS and DPS. This revenue requirement comprises the financial costs attributed to electricity, comprising:

   i. direct costs of electricity purchases from IPPs;

   ii. indirect costs allocated to electricity, such as the allowed revenue in respect of OPWP-own costs and licence fee; and

   iii. the portion of joint costs at the IWPPs allocated to electricity.

c) Tariffs are scaled to reflect short-run marginal economic costs. The scaling factor is determined to limit total revenues to the electricity revenue requirement. The scaling factor is multiplicative, and applies uniformly to both capacity and energy costs for the following reasons:

   i. scaling of capacity costs alone would be insufficient;

   ii. given the relatively narrow time bands for peak demand, some reduction is necessary to the large differentials between peak and off-peak period tariffs as a practical matter, in order to encourage peak demand reduction rather than merely shifting the time of the peak demand. Multiplicative scaling reduces the large peak and off-peak differentials, whereas separate scaling of economic capacity and energy costs further exacerbates the large peak and off-peak differentials as it impacts disproportionately on energy costs.

d) The allocation of joint costs at IWPPs between electricity and water is based on sharing the benefits of joint production.

e) The current billing determinant remains appropriate. This is a single variable charge expressed in RO/MWh that combines both capacity and energy components (and, thus, ensures that variable charges better reflect underlying economic costs than would be the case if separate fixed and variable charges were introduced).

Tariff Structure

Concerning tariff structure, and specifically the rate bands, the methodology comprises the following steps:

1. Establish input data to the Power System Simulation model. The input data include projected demand (provided by the Demand Forecast model), operating and cost characteristics of generation units, projected fuel prices and value of lost load (VOLL)

at economic prices, and unit operating constraints such as must-run generation and outages of equipment at the combined cycle plants and IWPPs[2].

2. Run the Power System Simulation model for many iterations with stochastic demand and plant availability to determine the hourly average SRMCs, SRMCCs and SRMECs for a system in which plant capacity has been manually adjusted to ensure generation adequacy according to required standards[3]. For a particular iteration and hour, there is either:

    a. no unserved energy: in which case the SRMCC is zero and the SRMEC is the incremental cost of the marginal plant (the highest cost plant running unconstrained in the hour); or

    b. Unserved energy: in which case the SRMCC is the VOLL less the incremental cost of the marginal plant and the SRMEC is the incremental cost of the marginal plant.

3. Identify rate bands for each of the MIS and DPS by examining the hourly profile of average SRMCs and manually grouping the profile into bands of hours having similar SRMCs.

4. Determine tariff levels separately for each of the MIS and DPS, separated into capacity and energy components, for the selected rate bands as the demand-weighted average of the SRMCs for each hour in the relevant rate band.

Level and Scaling

Concerning the level and scaling of the tariffs, the methodology comprises the following steps:

1. Establish the purchase costs of electricity. These are the expected costs for the tariff year, projected according to the P(W)PA terms for each plant. They include the following components:

    a. Capital and fixed O&M (FOM) costs for each plant based on escalation of base PWPA charges and projected availability;

    b. Fuel and variable O&M (VOM) costs associated with electricity production at each plant, based on the projected dispatch provided by the Power System Simulation model using financial fuel prices;

    c. Fuel and VOM costs associated with water production at each IWPP based on escalation of base PWPA charges and projection of the historical trend in water production at each IWPP.

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[2] Of necessity, given the complex configurations of steam turbines, gas turbines, heat recovery steam generators and auxiliary boilers that can be in service at the IWPPs, we make a number of simplifications.

[3] The current generation security standard requires that there should be no more than 24 LOLH each year; whereas the GCC interconnection standard requires no more than 5 LOLH each year for the interconnected system. For BST purposes only, we have chosen to use around 5 LOLH to determine the SRMC profile. Using fewer LOLH to determine the SRMCs tends to mean sharper peaks in the SRMC profile as the times of loss of load, and hence material system stress and material SRMCCs, become confined to fewer hours.

2. Establish other allowed costs for the tariff year, comprising the projected amounts for:

    a. OPWP own costs;

    b. 0.25% margin on projected purchase costs;

    c. Licence fee;

    d. Correction factor;

    e. Extraordinary costs, if applicable.

3. Allocate financial costs to electricity and water for both the MIS and DPS, as set out more fully below, to determine the respective revenue requirements and their separation into fixed and variable components (with respect to output).

4. Set aside the Correction Factor (K-factor) from the other elements of the revenue requirement. The K-factor is a cost carryover from the previous year, and therefore not part of the underlying costs of the current year. This will be included in the Tariff Balancing Charge (TBC), discussed further below.

5. Scale the SRMC-based tariff levels to the electricity revenue requirement using the following procedure:

    a. Scale the capacity and energy components of the SRMC-based tariffs by a single multiplicative factor to match the electricity revenue requirement. The same factor is applied to both MIS and DPS tariff levels that were determined based on their respective SRMCs;

    b. Make an equity adjustment to assure (i) that tariff levels on each system have parity in the winter period, and (ii) that in aggregate the tariff levels on each system result in the same average tariff (revenue requirement divided by total electricity production). For the MIS, this may require a minor adjustment to the on-peak weekday tariff. For the DPS, being the smaller system, this may require a single factor multiplier applied to all winter period tariffs (Nov-Mar) to equal the MIS winter tariff, and then a further adjustment to all summer period tariffs (Apr-Jun) such that the DPS average tariff will equal the system average tariff.

    c. Round the resulting tariff levels to integer values and project the revenue resulting from the rounded tariffs. Assess the extent of over-recovery or under-recovery of the tariffs, as the Maximum Allowed Revenue (MAR) less the projected revenue, and apply this value to the TBC.

6. Determine the total revenue required of the TBC as the sum of the K-factor and the result of step 5(d) above (i.e., MAR less projected rate-band revenue). The Tariff Balancing Charge is this value divided by total electricity production. The TBC may be positive or negative in a given year, and is applied as a flat charge (or credit) per unit of electrical energy delivered.

Water BST Methodology

The principles used to develop the water BST are described below, followed by the key steps in the methodology dealing firstly with structure and secondly with level and scaling. Figures 3 and 4 show the main steps in the development of the water BST.

Figure 3 : Steps to determine the structure of the water BST

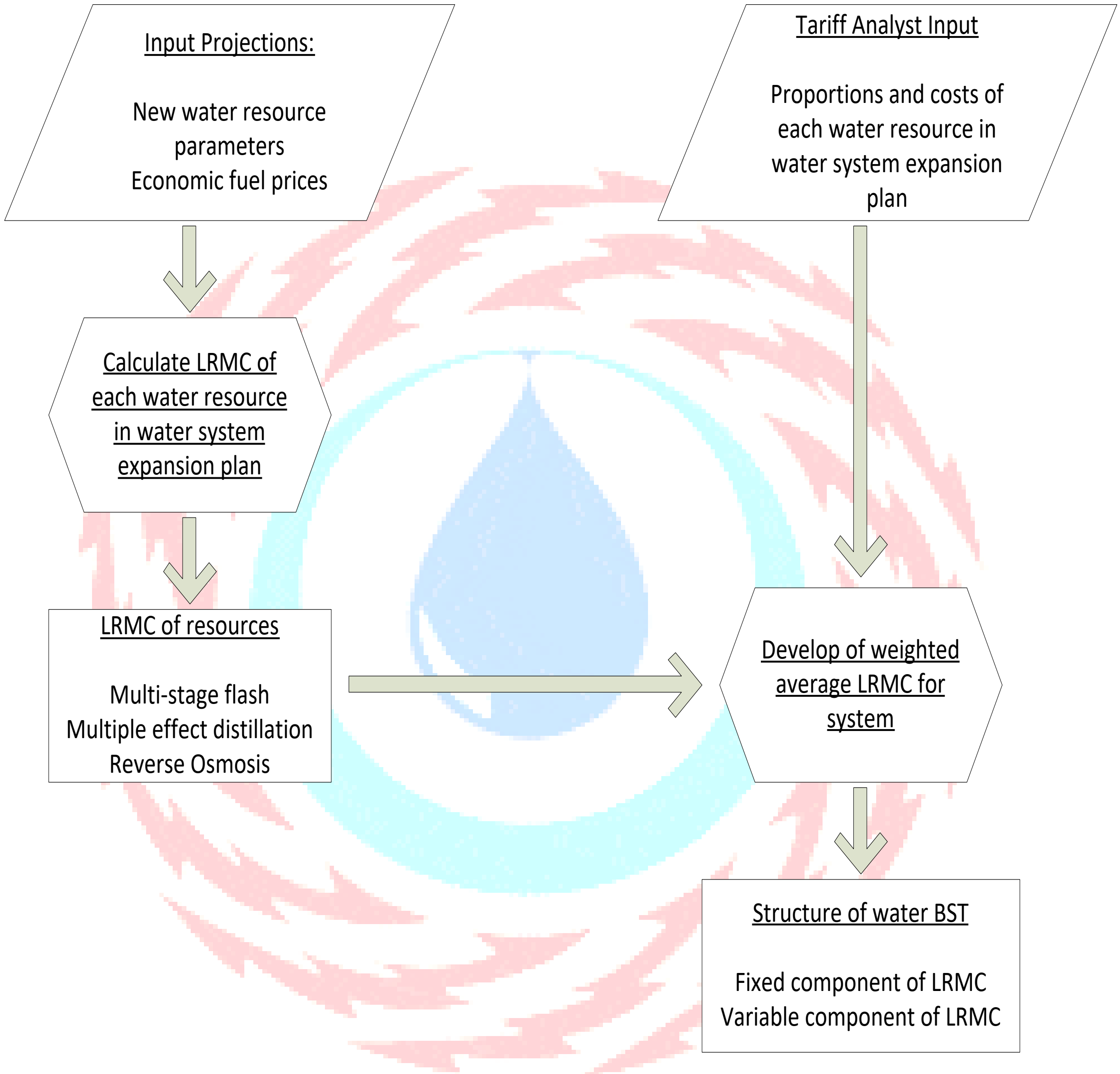
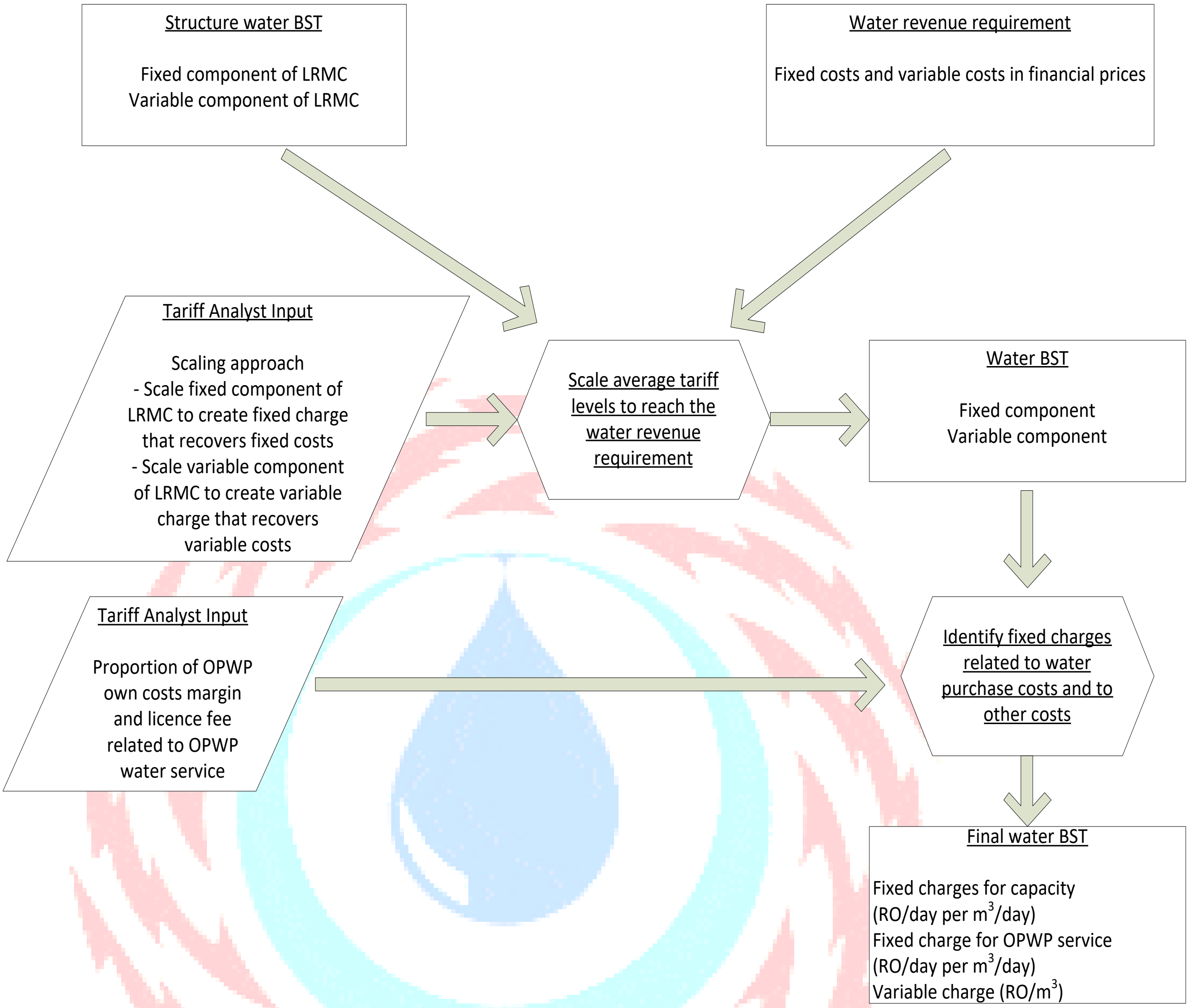


Figure 4 : Steps to determine the final water BST which covers the water revenue requirement



Principles

As for electricity, a key design choice is between structures that reflect SRMCs and structures that reflect long-run marginal costs (LRMCs). However, the choice is complicated by (a) absence of a suitable "water dispatch" model to determine SRMCs or LRMCs and (b) availability of substitute water resources that may not be priced at marginal economic costs.

The approach is similar to that for electricity with the exceptions that:

a) The structure of the BST is based on the long run marginal economic costs, as there is little spare capacity at existing water production facilities, which means that incremental demand will require development of new capacity; and

b) The fixed and variable components of the tariff are scaled by *separate* multiplicative factors, to recover respectively the fixed component and the variable component of the water revenue requirement.

Accordingly, the water BST methodology adheres to the following principles:

a) The structure of the BST is set to reflect long run marginal economic costs.

b) The level of the BST is set to achieve the water revenue requirement. This revenue requirement comprises the financial costs attributed to water, comprising:

   i. Direct costs of water purchases;

   ii. Indirect costs allocated to water, such as the allowed revenue in respect of OPWP own costs and licence fee; and

   iii. The portion of joint costs at the IWPPs that are allocated to water.

c) Separate multiplicative factors are used to scale the fixed and variable components of the tariff. Separate factors are used rather than a uniform factor (as in the electricity BST methodology) for the following reasons:

   i. If scaling were by fixed costs alone, this could lead to unreasonable charges for the IWPPs that have relatively low fixed costs;

   ii. OPWP will be less exposed to within-year volume volatility (because variable revenue will be more closely linked to variable costs).

d) The allocation of joint costs at IWPPs between electricity and water is based on sharing the benefits of joint production.

e) The current billing determinants remain appropriate. These comprise

   i. Fixed charges for capacity expressed in RO/day per m3/day;

   ii. Fixed charges for OPWP service expressed in RO/day per m3/day; and

   iii. Variable charges for water delivered expressed in RO/m3.

Structure

Concerning structure, the methodology comprises the following four steps:

1. Establish input data required to estimate LRMCs and projected actual costs of water production for the principal water resources. These inputs include projected technology capital and FOM costs, economic lifetimes, fuel prices, and VOM costs at economic prices. LRMCs are projected to be those associated with new RO technology, benchmarked to the most recent tariffs arising out of OPWP competitive tenders for IWPs. With respect to assessing the cost of water production under joint production at CCGT/MSF plants, the methodology is described in a subsequent section below, Allocation of Joint Costs to Electricity and Water. In principle, we assume for these plants that (i) the electricity sector bears the costs that it would have incurred if electricity were produced on a stand-alone CCGT with a relatively high

thermal efficiency, and (ii) the water sector bears all other costs associated with joint production[4 5].

2. Determine the LRMC of each new water resource using the input data.

3. Establish input proportions of water production on each new water resource[6]. In the absence of better information, for 2019 BST purposes, we assume that all new water production will be by RO plant in all zones of the MIS and Dhofar. The variable costs of RO plants are time differentiated—varying by time of day and season of the year—reflecting the impact of time-differentiated electricity costs (as seen in the electricity BST).

4. Determine the fixed and variable components of the average LRMC by taking a weighted average of the fixed and variable costs of the various technologies.

Level and Scaling

Concerning the tariff level and scaling, the methodology comprises the following four key steps:

1. Take the fixed and variable components of the water revenue requirement (established as described under the electricity BST).

2. Scale each of the fixed and variable components of the LRMC-based tariffs by a separate multiplicative factor to obtain, respectively, the fixed and variable components of the water revenue requirement.

3. Identify the proportion of fixed charges that recovers the water purchase costs and the other costs allocated to water. This step relies on a historical analysis of the proportions of OPWP-own costs that relate to the water sector.

4. Establish the final water BST with three billing determinants:

    a. Fixed charges for capacity expressed in RO/day per m^3/day;

    b. Fixed charges for OPWP service expressed in RO/day per m^3/day; and

    c. Variable charges for water delivered expressed in RO/m^3, differentiated into two rate bands for on-peak and off-peak periods, and by month.

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[4] At a combined CCGT/MSF plant, such costs would include: (i) the capital costs of the distillers and the heat recovery steam generators connected to the GTs, (ii) the additional capital costs of the larger sea water intakes and outfalls necessary to accommodate the larger water volumes required, and (iii) the additional fuel costs due to reduced thermal efficiency of the CCGT/MSF plant.

[5] See for example "Energy and Cost Allocation in Dual Purpose Power and Desalination Plants", by N M Wade, WSTA/EDS workshop on privatization in water supply, Bahrain, February 1999 referenced in OPWP report "Salalah new generating capacity strategy" dated 2011.

[6] If cost were the only consideration, OPWP's 2011 report "Salalah new generating capacity strategy" suggests that, for gas prices above about 1.0USD/MMBTU, reverse osmosis (RO) has lower total costs than either multi-effect distillation (MED) under joint production or multi-stage flash distillation (MSF) under joint production and, hence, all new water production would be from reverse osmosis plants. However, for a number of reasons, security of supply considerations may suggest that new water production should be from a range of technologies. This remains a potential issue for further study.

The fixed charges for capacity and fixed charges for the OPWP service are listed separately, because the availability rebate applies to fixed charges for capacity only.

Allocation of Joint Costs To Electricity and Water

The following approach has been adopted to allocate the joint costs of production purchased from IWPPs:

1. Determine the total cost for expected electricity and expected water production at each I(W)PP, separated into fixed and variable components. For example, the total purchase costs in respect of an electricity-only plant (e.g., Manah) is calculated from the PPA parameters and from the Power System Simulation model, by summing:

    a. Fuel and VOM costs from the Power System Simulation model;

    b. Capital and FOM costs from the PPA; and

    c. Other costs from the PPA, such as the annual generation licence fee and connection fee (expressed on a monthly basis rather than annually)[7].

2. Allocate direct costs as follows:

    a. To the electricity sector, the costs of IPPs and any separately identified costs of stand-alone electricity facilities at the IWPPs (such as the GTs at Al Ghubrah);

    b. To the water sector, any separately identified costs of any stand-alone water facilities at the IWPPs.

3. Allocate joint costs at IWPPs as follows:

    a. Determine the stand-alone costs for expected electricity and expected water production at the time the plant was conceived[8]. In this regard, stand-alone electricity production is based on a gas-fired CCGT in all cases. The reference technology for stand-alone water desalination differs for some plants, as follows:

        i. gas-fired multi-stage flash (MSF) distillation for Barka I, Sohar and Al Ghubrah[9]; and

        ii. reverse osmosis (RO) for Barka II and the DPS[10].

[7] Changes in licence fees and connection fees are recoverable under "change of law" provisions in the PPA. Any other costs recoverable as a result of the "change in law" provisions of the PPA would also be included here.

[8] Except for Al Ghubrah IWPP, for which we estimate electricity and water cost allocations from projected purchase costs under the PWPA. As Al Ghubrah IWPP is a complex plant that contains several CCGT configurations and several blocks, the stand-alone costs for Al Ghubrah for a particular configuration cannot readily be determined at the time when the plant was conceived.

[9] OPWP uses the costs of stand-alone CCGT and stand-alone MSF plants set out in the Fichtner analysis conducted for the Sohar IWPP in 2003.

[10] OPWP uses the stand-alone CCGT and stand-alone RO plants set out in the Mott MacDonald analysis conducted for the DPS in 2011.

b. Allocate the joint cost for expected electricity and expected water production under the PWPA to electricity and water in proportion to the relevant stand-alone costs of electricity and water (equivalent to allocating the cost savings from joint production to electricity and water in proportion to the respective stand-alone costs[11]).

We allocate other allowed costs as follows:

a) OPWP-own costs are allocated based on historical estimates of the proportions of OPWP staff time inputs that relate to the various activities.

b) 0.25% margin on purchase costs is allocated to electricity and water in proportion to the respective purchase costs including allocated joint costs.[12]

c) Licence fee is also allocated to electricity and water in proportion to the respective purchase costs.

d) Correction factor includes adjustments to be made to the tariff rates based on the K-Factor, the difference between the Maximum Allowed Revenue and the Proposed Revenue, and Liquidated Damages (if any).

[11] Economic theory provides no definitive allocation of joint costs. Instead, economic theory merely provides a ceiling and a floor to the allocation: the ceiling is set by the stand alone cost of production; and the floor is set by the incremental cost under joint production.

[12] Steps a) and b) are done indirectly by levying a service charge on water capacity which is deemed to represent an appropriate share of cost and margin.

Annex 1: Electricity BST for 2019

I) MAIN INTERCONNECTED SYSTEM (MIS)

MIS Electricity BST (RO/MWh)

Rate band	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Weekday Off Peak	12	12	12	14	16	16	16	16	16	14	12	12
Weekend Off Peak	12	12	12	14	16	16	16	16	16	14	12	12
Weekday Night Peak	12	12	12	14	25	25	25	22	22	14	12	12
Weekend Night Peak	12	12	12	14	25	25	25	22	22	14	12	12
Weekday Day Peak	12	12	12	14	67	67	67	26	26	14	12	12
Weekend Day Peak	12	12	12	14	36	36	36	20	20	14	12	12

MIS definition of rate bands - Sunday to Thursday (Weekday Rates in RO/MWh)

Hour ending	Rate band	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1.00	Night Peak	12	12	12	14	25	25	25	22	22	14	12	12
2.00		12	12	12	14	25	25	25	22	22	14	12	12
3.00	Off Peak	12	12	12	14	16	16	16	16	16	14	12	12
4.00		12	12	12	14	16	16	16	16	16	14	12	12
5.00		12	12	12	14	16	16	16	16	16	14	12	12
6.00		12	12	12	14	16	16	16	16	16	14	12	12
7.00		12	12	12	14	16	16	16	16	16	14	12	12
8.00		12	12	12	14	16	16	16	16	16	14	12	12
9.00		12	12	12	14	16	16	16	16	16	14	12	12
10.00		12	12	12	14	16	16	16	16	16	14	12	12
11.00		12	12	12	14	16	16	16	16	16	14	12	12
12.00		12	12	12	14	16	16	16	16	16	14	12	12
13.00		12	12	12	14	16	16	16	16	16	14	12	12
14.00	Weekday Day Peak	12	12	12	14	67	67	67	26	26	14	12	12
15.00		12	12	12	14	67	67	67	26	26	14	12	12
16.00		12	12	12	14	67	67	67	26	26	14	12	12
17.00		12	12	12	14	67	67	67	26	26	14	12	12
18.00	Off Peak	12	12	12	14	16	16	16	16	16	14	12	12
19.00		12	12	12	14	16	16	16	16	16	14	12	12
20.00		12	12	12	14	16	16	16	16	16	14	12	12
21.00		12	12	12	14	16	16	16	16	16	14	12	12
22.00		12	12	12	14	16	16	16	16	16	14	12	12
23.00	Night Peak	12	12	12	14	25	25	25	22	22	14	12	12
24.00		12	12	12	14	25	25	25	22	22	14	12	12

MIS definition of rate bands – Friday & Saturday (Weekend Rates in RO/MWh)

Hour ending	Rate band	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1.00	Night Peak	12	12	12	14	25	25	25	22	22	14	12	12
2.00		12	12	12	14	25	25	25	22	22	14	12	12
3.00	Weekend Off Peak	12	12	12	14	16	16	16	16	16	14	12	12
4.00		12	12	12	14	16	16	16	16	16	14	12	12
5.00		12	12	12	14	16	16	16	16	16	14	12	12
6.00		12	12	12	14	16	16	16	16	16	14	12	12
7.00		12	12	12	14	16	16	16	16	16	14	12	12
8.00		12	12	12	14	16	16	16	16	16	14	12	12
9.00		12	12	12	14	16	16	16	16	16	14	12	12
10.00		12	12	12	14	16	16	16	16	16	14	12	12
11.00		12	12	12	14	16	16	16	16	16	14	12	12
12.00		12	12	12	14	16	16	16	16	16	14	12	12
13.00		12	12	12	14	16	16	16	16	16	14	12	12
14.00	Weekend Day Peak	12	12	12	14	36	36	36	20	20	14	12	12
15.00		12	12	12	14	36	36	36	20	20	14	12	12
16.00		12	12	12	14	36	36	36	20	20	14	12	12
17.00		12	12	12	14	36	36	36	20	20	14	12	12
18.00	Weekend Off Peak	12	12	12	14	16	16	16	16	16	14	12	12
19.00		12	12	12	14	16	16	16	16	16	14	12	12
20.00		12	12	12	14	16	16	16	16	16	14	12	12
21.00		12	12	12	14	16	16	16	16	16	14	12	12
22.00		12	12	12	14	16	16	16	16	16	14	12	12
23.00	Night Peak	12	12	12	14	25	25	25	22	22	14	12	12
24.00		12	12	12	14	25	25	25	22	22	14	12	12

II) Dhofar Power System

DPS Electricity BST (RO/MWh)

Rate band	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Weekday On Peak (proposed change to Night Peak)	12	12	12	29	48	48	15	15	19	19	12	12
Weekend On Peak (proposed change to Night Peak)	12	12	12	20	29	29	13	13	15	15	12	12
Weekday Off Peak Morning	12	12	12	15	26	26	12	12	13	13	12	12
Weekend Off Peak Morning	12	12	12	15	26	26	12	12	13	13	12	12
Weekday Mid Peak (proposed change to Day Peak)	12	12	12	20	45	45	12	12	15	15	12	12
Weekend Mid Peak (proposed change to Day Peak)	12	12	12	15	23	23	12	12	13	13	12	12
Weekday Off-Peak Night (proposed change to Off-Peak Afternoon)	12	12	12	15	23	23	12	12	15	15	12	12
Weekend Off Peak Night (proposed change to Off-Peak Afternoon)	12	12	12	15	23	23	12	12	15	15	12	12

DPS definition of rate bands - Sunday to Thursday (Weekday Rates in RO/MWh)

Hour ending	Rate band	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1.00	Night-Peak	12	12	12	29	48	48	15	15	19	19	12	12
2.00		12	12	12	29	48	48	15	15	19	19	12	12
3.00		12	12	12	29	48	48	15	15	19	19	12	12
4.00	Off-Peak Morning	12	12	12	15	26	26	12	12	13	13	12	12
5.00		12	12	12	15	26	26	12	12	13	13	12	12
6.00		12	12	12	15	26	26	12	12	13	13	12	12
7.00		12	12	12	15	26	26	12	12	13	13	12	12
8.00		12	12	12	15	26	26	12	12	13	13	12	12
9.00		12	12	12	15	26	26	12	12	13	13	12	12
10.00		12	12	12	15	26	26	12	12	13	13	12	12
11.00	Day-Peak	12	12	12	20	45	45	12	12	15	15	12	12
12.00		12	12	12	20	45	45	12	12	15	15	12	12
13.00		12	12	12	20	45	45	12	12	15	15	12	12
14.00		12	12	12	20	45	45	12	12	15	15	12	12
15.00		12	12	12	20	45	45	12	12	15	15	12	12
16.00		12	12	12	20	45	45	12	12	15	15	12	12
17.00	Off-Peak Afternoon	12	12	12	15	23	23	12	12	15	15	12	12
18.00		12	12	12	15	23	23	12	12	15	15	12	12
19.00		12	12	12	15	23	23	12	12	15	15	12	12
20.00		12	12	12	15	23	23	12	12	15	15	12	12
21.00	Night-Peak	12	12	12	29	48	48	15	15	19	19	12	12
22.00		12	12	12	29	48	48	15	15	19	19	12	12
23.00		12	12	12	29	48	48	15	15	19	19	12	12
24.00		12	12	12	29	48	48	15	15	19	19	12	12

DPS definition of rate bands – Friday & Saturday (Weekend Rates in RO/MWh)

Hour ending	Rate band	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1.00	Night-Peak	12	12	12	20	29	29	13	13	15	15	12	12
2.00		12	12	12	20	29	29	13	13	15	15	12	12
3.00		12	12	12	20	29	29	13	13	15	15	12	12
4.00	Off-Peak Morning	12	12	12	15	26	26	12	12	13	13	12	12
5.00		12	12	12	15	26	26	12	12	13	13	12	12
6.00		12	12	12	15	26	26	12	12	13	13	12	12
7.00		12	12	12	15	26	26	12	12	13	13	12	12
8.00		12	12	12	15	26	26	12	12	13	13	12	12
9.00		12	12	12	15	26	26	12	12	13	13	12	12
10.00		12	12	12	15	26	26	12	12	13	13	12	12
11.00	Day-Peak	12	12	12	15	23	23	12	12	13	13	12	12
12.00		12	12	12	15	23	23	12	12	13	13	12	12
13.00		12	12	12	15	23	23	12	12	13	13	12	12
14.00		12	12	12	15	23	23	12	12	13	13	12	12
15.00		12	12	12	15	23	23	12	12	13	13	12	12
16.00		12	12	12	15	23	23	12	12	13	13	12	12
17.00	Off-Peak Afternoon	12	12	12	15	23	23	12	12	15	15	12	12
18.00		12	12	12	15	23	23	12	12	15	15	12	12
19.00		12	12	12	15	23	23	12	12	15	15	12	12
20.00		12	12	12	15	23	23	12	12	15	15	12	12
21.00	Night-Peak	12	12	12	20	29	29	13	13	15	15	12	12
22.00		12	12	12	20	29	29	13	13	15	15	12	12
23.00		12	12	12	20	29	29	13	13	15	15	12	12
24.00		12	12	12	20	29	29	13	13	15	15	12	12

III) MUSSANDAM SYSTEM

Mussandam Electricity BST – Fixed Charge Component

Month	Fixed Charges
	RO/MW/Hr
Jan	6.4
Feb	6.4
Mar	6.4
Apr	11.3
May	26.6
Jun	26.6
Jul	26.6
Aug	19.0
Sep	19.0
Oct	6.5
Nov	6.5
Dec	6.5

Mussandam Electricity BST – Variable Charge Component

Month	Variable Charges
	RO/MWh
Jan	15.198
Feb	15.198
Mar	15.198
Apr	15.198
May	15.198
Jun	15.198
Jul	15.198
Aug	15.198
Sep	15.198
Oct	15.198
Nov	15.198
Dec	15.198