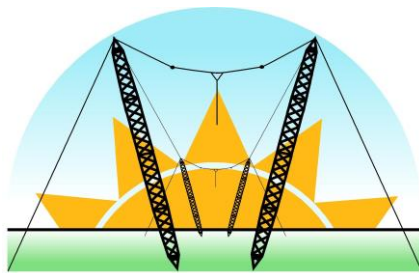


OPERATING AND REPORTING MANUAL

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USER GUIDE AND TARIFF RULEBOOK

Version 1.0 - March 2019



Electricity Control Board
35 Burg Street
Windhoek
Namibia

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Abbreviations

ADMD	after diversity maximum demand
ECB	Electricity Control Board
EDI	electricity distribution industry
ESI	electricity supply industry
GAAP	generally accepted accounting principles
IBT	inclining block tariff
IPP	Independent Power Producer
kVA	kilo-Volt-Ampere
kWh	kilo-Watt hour
LAS	Local Authority Surcharge
LV	low voltage
MD	maximum demand
MME	Ministry of Mines and Energy
MV	medium voltage
MWh	mega-Watt hour
NEST	national electricity support tariff
ORM	Operating and Reporting Manual
ORM-FR	Operating and Reporting Manual for Financial Reporting
ORM-TD	Operating and Reporting Manual for Tariff Determination
RED	Regional Electricity Distributor
TD	tariff determination
TOU	time-of-use
WACC	weighted average cost of capital

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1. Purpose and Background

1.1 Purpose

This 'ORM User Guide and Tariff Rulebook' summarises the main approach to correctly and consistently populate the **ORM-TD** (TD = Tariff Determination) and **ORM-FR** (FR = Financial Reporting) workbooks containing the operating and reporting schedules as per the Electricity Control Board's (ECB) rules and requirements.

1.2 Background

The Electricity Act, No. 2 of 2000, as amended in the Electricity Act, No. 4 of 2007, established the ECB. Its objectives are to regulate the generation, transmission, distribution and supply of electricity in Namibia, thereby ensuring the orderly operation of the country's electricity supply and distribution industry while protecting electricity end-users in accordance with Government policy.

Entities wishing to be licensed to distribute and supply electricity to end-users must fulfil specific distribution license conditions as are set by the ECB. These include the application and use of a consistent and transparent electricity tariff determination methodology as was developed by the ECB.

In 2018, the ECB commissioned the National Electricity Tariff Study for the Electricity Distribution Industry. The study entailed a complete review and update of Namibian electricity distribution tariffs, including the revision of the ECB's operating and reporting schedules and the Operating and Reporting Manual (ORM).

2. The Operating and Reporting Manual (ORM)

2.1 Structure of the ORM Workbooks

The ORM workbooks issued by the ECB and used by licensees comprise three distinct Excel workbooks which serve different purposes:

- The **ORM-TD** is used for tariff determination purposes. It must be completed and submitted by the licensee for each application for tariff approval. The ORM-TD usually contains forecast numbers, both for budgets and sales.
- The **ORM-FR** is used for reporting actual final results (usually audited results) of a licensee for a financial period to the ECB. It must be submitted by the licensee after completion of the audit of the financial year in question. The ECB may refuse to consider future tariff reviews if a licensee fails to submit the completed ORM-FR for the last financial year.
- The **ORM-Ringfencing** guideline is availed to licensees as an optional tool to assist local authorities and other licensee entities that are not solely dedicated organisations for electricity distribution and supply to financially ring-fence their electricity distribution and supply operations. Such ring-fencing is usually a requirement stated in the license conditions. The ECB may require affected licensees to submit a completed ORM-Ringfencing as supporting document to their ORM-FR.

2.2 Structure of this Document

This 'ORM User Guide and Tariff Rulebook' comprises of four parts, namely

- **Part A – The Tariff Rulebook**, which describes the design of the Namibian distribution tariffs and how they are determined;
- **Part B – ORM: Tariff Determination** describes how distribution licensees are to complete the schedules contained in the ORM-TD Excel workbook;
- **Part C – ORM: Financial Reporting** describes the financial data and information that licensees are required to complete after the end of a given financial year; and
- **Parts D – ORM: Maintenance and Timeline of Submissions** describes the maintenance requirements to keep the data and information needed to populate the ORM Excel workbooks current and provides the timeline of submissions of the licensee's tariff and financial information to the ECB.

3. Part A – The Tariff Rulebook

This part of the 'ORM User Guide and Tariff Rulebook' describes the design and determination of Namibian distribution tariffs.

3.1 Introduction

Tariffs are best designed in accordance with specific objectives that underpin the tariff setting methodology.

The principal requirement underpinning the Namibian distribution tariff methodology is that tariffs and the associated tariff structures must be cost reflective¹. This principle is the departure point that shapes the guideline presented in the following sections.

The principle of cost reflective tariffs is based on the realisation that economic efficiency is optimised by end-user prices that reflect (as best as possible) the true cost of services. The rationale is that cost reflective tariffs allow users of services to make the most rational decisions regarding the use of such services, thereby promoting economically efficient consumption.

The requirement for the cost reflectivity of tariffs has two main dimensions, namely that costs

- a) are allocated as accurately as is reasonably achievable to those connection (customer) categories that use services that incur costs, in proportion to the use of such services; and
- b) are further allocated to tariff charge types that best reflect the nature of the costs incurred.

The pure application of the above requirements is often modified or even made impossible by factors such as limited data quality, physical and/or practical limitations such as the type of metering equipment used, specific social and/or political considerations, limiting the complexity of tariffs and the tariff determination process, and many others. Based on this realisation, the sections below introduce and motivate a tariff setting approach taking the above considerations into account.

The design of tariff charges must be based on a rational and limited set of charge types. These are to be designed to enable their transparent allocation to those customer categories that are actual users of specific services. Most tariff types include several different tariff charges – a notable exception are prepaid tariffs which traditionally only comprise of an energy charge.

It is important to recognise that tariffs and the underlying tariff charges evolve in time. This is because the basis on which tariffs are determined is changing over time, which in turn results in successive changes of tariff charges. From a regulatory perspective it is desirable that this development in time is guided by overarching tariff objectives and follows a deliberate tariff trajectory that is defined by tariffs moving towards their desirable long-term state.

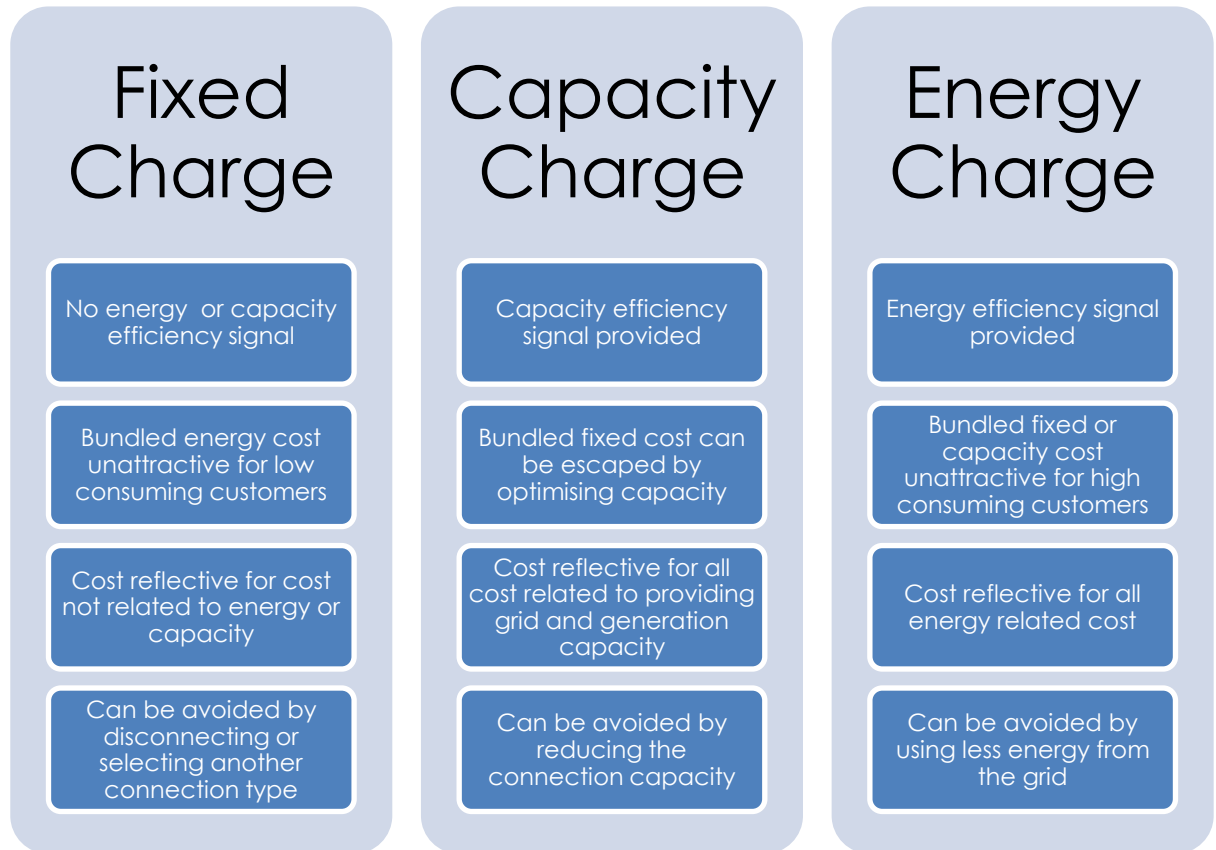
3.2 General Considerations in the Application of Charge Types

Several factors need to be considered when deciding how best to structure tariff charges to be as cost reflective as possible. Figure 1 illustrates some aspects to consider when allocating

¹ As set out in the National Energy Policy of 2017, policy statement P5.e.

charge types and deciding on the charges to be applied to a given connection. It uses the phrase “bundled cost”, which refers to other cost types being recovered as part of a given charge type. To illustrate: fixed costs recovered through capacity charges are “bundled” into capacity charges. While the bundling of costs is often unavoidable it may also lead to a dilution of specific cost signals to consumers, which is undesirable and may potentially hold risks to end-users as well as licensees.

Figure 1: Some considerations for charge type allocations



Fixed charges provide no energy efficiency signals to customers. They can be cost reflective and fully recover the relevant fixed costs, but they cannot be avoided by customers except through disconnecting or selecting another connection category without such charges (if these available). For consumers using larger amounts of energy and capacity, fixed charges are usually small in comparison to energy and capacity costs and are therefore a good instrument to recover fixed costs. For consumers using little energy and capacity, fixed charges may represent a significant portion of the total cost of supply and may therefore be unpopular. Bundling non-fixed costs into fixed charges may incentivise customers to alternatives to the supply of electricity through the grid.

Capacity charges are used to recover all costs that can reasonably be related to the provision of network capacity and generation capacity. They provide a signal to use capacity efficiently, motivated by the fact that providing network and generation capacity carries significant costs. Capacity charges do not represent fixed revenue to a licensee since customers have the option to change the capacity purchased. They are considered “semi-variable” because changing connection capacity usually involves an application process and

physical changes to the connection, i.e. they involve actions taken by the licensee and cannot be implemented unilaterally and without notice by the customer. When bundled, capacity charges may represent a risk to licensees, which is however limited by the slow pace at which capacity can be changed. Customers can reduce connection costs by reducing their network capacity.

Energy charges are the cost reflective manner of recovering all costs related to energy purchased or sold (including, for example, vending costs incurred in relation to kWh sold) and arise because the generation of electrical energy incurs costs. They are fully variable revenue to the licensee. Customers can instantaneously decide to use more/less energy without having to notify the supplier. When bundled, energy charges may incentivise customers to use less energy and/or install own generation, which represents a risk to licensees.

Time and/or seasonal variations in energy (and potentially capacity) costs can be included in the design of energy and capacity charges and their associated application rules. Time-of-use (TOU) energy tariffs are an example of making energy charges better reflect the fact that the cost of generating electricity is not constant but fluctuates with overall demand on the electricity network as well as the production profiles of different generators that are deployed to serve this demand. Therefore, time- and seasonally-differentiated tariffs may improve the cost reflectivity of charges. However, they also add complexity to the customer's bill, which is not desirable nor effective for all customer groups. More complex charge structures must therefore be applied with due consideration for the costs involved in implementation (e.g. metering) and the customers' ability to interpret and react to such tariff signals.

The complexity of tariff structures must be appropriate for the customer group to which they are applied. Large electricity customers usually have well-developed capacities and abilities to respond to complex tariff signals and structures, while small customers often have very limited capacities to deal with tariff complexity.

The tariff methodology seeks to allocate costs to the different charge types taking the above rationale into account. Licensees are encouraged to keep this rationale in mind when designing their tariff structures and tariff charges.

3.3 Tariff Setting Guidelines

3.3.1 Fixed Charges

The electricity distribution industry (EDI) incurs substantial fixed costs that are not directly related to the provision of either energy or capacity. As a result, such costs should not be allocated to energy/capacity charges but should rather be evenly apportioned amongst all connections served by the distributor.

From the perspective of distributors, fixed charges are a source of guaranteed income provided that customers remain on the grid. However, from the perspective of end-users, fixed charges are often viewed as being unjustified as there is nothing that customers can do to reduce such charges except defect from the grid. This is one of the main arguments suggesting

that “high” fixed charges are responsible – amongst others – for incentivising customers to defect from the grid as self-generation and storage are increasingly mainstreamed.

Based on the developments taking place on the customer-end of the EDI, it is argued that fixed charges must be applied with due care. They should not be introduced to residential customers that do not already face such charges. Instead, fixed costs in this connection category should be recovered through capacity charges (or energy charges for prepaid connections). Also, the level of fixed charges must be carefully set, and should not dominate the total electricity bill of an ordinary end-user. As a guideline, fixed charges should not exceed the capacity charge for the smallest available connection size in the specific customer segment, although it is noted that such an approach is not entirely objective. Lastly, as social tariffs are only available to prepaid connections, they do not incur fixed charges.

At a practical level, licensees should implement fixed charges for all three phase connections, including demand metered connections. The level of these fixed charges should include recovery of metering cost, especially if remote/automated metering is implemented.

3.3.2 Capacity Charges

Every network connection avails capacity. The cost associated with the provision of capacity is expressed as a capacity charge that scales proportionally with the amount of capacity that is provided.

Capacity charges based on the current limiter setting apply to all connections except prepaid and demand metered connections. For demand metered connections, the cost of capacity is recovered through maximum demand charges.

Capacity charges for post-paid end-users without demand metering must be reflective of the cost associated with the capacity provided based on an estimate/empirical after diversity maximum demand (ADMD). While one could argue that installed capacity should be used to apportion capacity cost, only the consumer connection asset itself is sized to the installed capacity, while all the up-stream network as well as bulk capacity purchases are driven by ADMD and not installed capacity. Based on this, capacity cost must be allocated according to ADMD and *not* on installed capacity.

From the end-user perspective, the advantage that capacity charges have over fixed monthly charges are that they allow users to reduce costs by opting for a smaller connection size. This drives efficiency and reduces the costs arising from peak demand use, which are significant. Because users can opt for a smaller connection, the expense/revenue due to capacity charges are ‘moderately variable’, when compared to energy charges that are fully variable (both in timing and amount). This renders capacity charge revenue more predictable, which is an advantage for end-users (as expenses can be forecast with greater accuracy) as well as the distributor (as revenue can be forecast with some degree of confidence).

There are, however, special cases where capacity charges are onerous for customers, specifically in the case of highly seasonal loads such as those used at some irrigation schemes, agricultural facilities, as well as seasonally dependant processing, packaging and cooling facilities. Charging an end-user operating a seasonal load the full capacity charge throughout the year for capacity that is only required for short periods renders a grid electricity connection less attractive and may therefore incentivise the use of a temporary generation plant.

Licensees could allow highly seasonal connections (with predictable firm demand) to be maximum demand metered, with specific provisions for seasonality (refer to maximum demand (MD) charges), even if the capacity is below the normal MD connection limit.

Alternatively, capacity charges could be waived/reduced during off-season periods, although this may be difficult to administer. Licensees should consider the matter and propose a most manageable approach to the ECB.

Generally, the ESI should move towards greater standardisation of current limiter sizes. This should include the way in which these are reported in the ORM and should result in the use of standardised summated Ampere ratings, as opposed to the reporting of nominal ratings as is currently used by most licensees.

The ECB intends to facilitate a process for the EDI to agree on a standard for publishing tariffs, to enhance the comparability of tariffs, and enhance the value of information that is provided to end-users, including the provision of tariffs for summated or nominal ratings.

Lastly, licensees must ensure that the charge rate per Ampere for capacity charges is the same for single- and three-phase connections of the same category (per summated Ampere).

3.3.3 Energy Charges

The National Distribution Tariff Study of 2018/19 recommends that energy charges should only include the cost of bulk energy, energy losses and other costs directly related to energy sales. While this recommendation holds for post-paid connections, it is not applicable for prepaid connections.

The application of the above recommendation implies that energy charges, expressed in N\$/kWh must be the same for single- and three-phase connections of the same category, with the assumption that they have comparable time-of-use (TOU) profiles. Similarly, TOU energy charges must only reflect the bulk provider's TOU rates plus a flat c/kWh charge to compensate for distribution losses. Where a licensee purchases significant power from Independent Power Producers (IPPs) on rates which are not differentiated on TOU, in addition to bulk TOU supplies, the ORM reflects the blended TOU rates based on both TOU and non-TOU purchases.

For inclining block tariff (IBT) rates on post-paid connections, the top rate must include the cost of bulk energy purchases plus losses, while lowest/lower (subsidised) rate(s) must be based on an understood and documented rationale of what is being subsidised. It is recognised that the top rate of residential and social tariffs of many licensees has historically be subsidised, however this subsidy may be reduced over time, subject to economic analysis by the ECB and policy decisions in this regard.

Arguably, once post-paid energy rates reflect only bulk energy costs plus losses, IBT-based energy charges should not be offered on post-paid connections unless there is a specific approved rationale for subsidising energy costs, which does not currently exist. Even the national electricity support tariff (NEST) mechanism sets the lowest IBT energy rate at the cost of bulk energy, i.e. the bulk energy cost is not being subsidised in the NEST.

For prepaid IBT rates, the top rate must be equal to the cost reflective rate at design cross-over point between pre- and post-paid connections. Lower (subsidised) rates are to be based on an understood and documented rationale of what is being subsidised, which currently only exists for the NEST mechanism.

3.3.4 Maximum Demand Charges

The main considerations regarding maximum demand (MD) charges are the same as for capacity charges as were covered in section 3.3.2.

Recently, MD charges included the concept of network access charges, where MD charges are charged on measured MD while network access charges are levied on notified MD or the highest actual demand recorded during a preceding 12-month period. This essentially splits the demand charge revenue into a fully predictable stream (from network access charges which are not monthly consumption related) and a partly variable revenue stream (from demand charges, which can vary between billing periods but are, for a continuously operating business, stable and predictable).

Not all licensees have implemented network access charges, and applications of how the network access quantity is calculated differs between licensees. Some use a minimum MD clause on the demand charges to ensure that a minimum income is derived from these charges, noting that demand charges are typically levied on at least 70% of notified demand.

For the sake of uniformity across the EDI, licensees should implement the schedule of MD and network access charges like NamPower's charges. This is to include definite rules, specifically on how a) the quantity for the access charge is determined and revised, b) during which TOU periods the MD is registered, c) how MD is notified and adjusted, and d) what the associated notice periods are. Such alignment with NamPower's practice will increase cost reflectivity across the industry, if NamPower's practices are cost reflective. The ECB will facilitate a process to reach agreement in the EDI on this matter.

There may be merit in considering the introduction of TOU-differentiated maximum demand charges, or billing only on maximum demand recorded during peak and standard hours (as is practiced by NamPower). This would incentivise customers to optimise their demand during high demand time slots.

Licensees must introduce a discount on MD and network access charges for medium voltage (MV) connected end-users, on the condition that such end-users comply with all legal safety requirements applicable to such installations². No discount must be given on fixed and energy charges. This discount is motivated by MV connected customers not using the transformation assets and low voltage network of the licensee and should therefore not be required to pay for those assets.

Special, extra-large power user tariffs, which by design already exclude certain distribution costs, must not automatically qualify for the above-mentioned discount, even though such end-users would likely be connected at MV. Licensees must grant the discount if the standard demand and access charges do include the distributor's LV and transformation costs. If this is not the case, the discount should not be availed.

Lastly, licensees must consider introducing concessions for highly seasonal connections, provided that their demand is predictable. For example, network access charges could be converted to an MD charge that is based on actual demand, while the concession is discontinued, or a penalty is applied if the end-user has a draw exceeding the agreed MD during the agreed off-season.

² A discount percentage of 9% was determined based on the industry average costs. Licensees are encouraged to compute the percentage applicable to their own cost composition.

3.3.5 Availability Charges

Availability charges were introduced to cover the cost of providing network infrastructure in areas with newly serviced properties until these are developed and connected to the grid. Often, property owners find such charges unpalatable, and distributors find it difficult to collect them as services are not actively being provided and there is little leverage to collect outstanding bills. Availability charges are charged as fixed monthly charges and are usually differentiated between residential and commercial properties.

The introduction of availability charges might be contemplated for customers defecting from the grid. From the distributors' perspective, such charges may seem justified as costs have been incurred in establishing infrastructure which would no longer be used when a customer disconnects from the grid, but which still incurs the same cost for maintenance and operations because it must be kept operational for other customers still connected to the grid as well as providing services like streetlights from which everyone benefits. One can also argue that recovering the same costs from a shrinking network user base will mean that those defecting will make the network more expensive for those remaining, leading into a defection spiral which may leave only those customers on the grid who can either not afford to make the investments necessary to defect or do not have the physical space to generate enough electricity for their own use. This can be considered socially unjust and used to motivate the implementation of availability charges for those defecting from the grid.

However, it is considered likely that such charges would be met with massive resistance from end-users thinking about defecting and could well be regarded as perpetuating technologies (and associated payments for services) that can be better met by other means. It is also considered possible that such charges may be found unconstitutional, as end-users can likely not be forced to pay for services that are not needed and/or are perceived as being obsolete. Such charges could also easily be construed as being anti-renewables as the bulk of self-generation that would be associated with grid defection is based on renewable energy. Since the Government of Namibia has various policies that promote the use of renewable energy in general, a move that can be construed as being against such policies may not be politically acceptable.

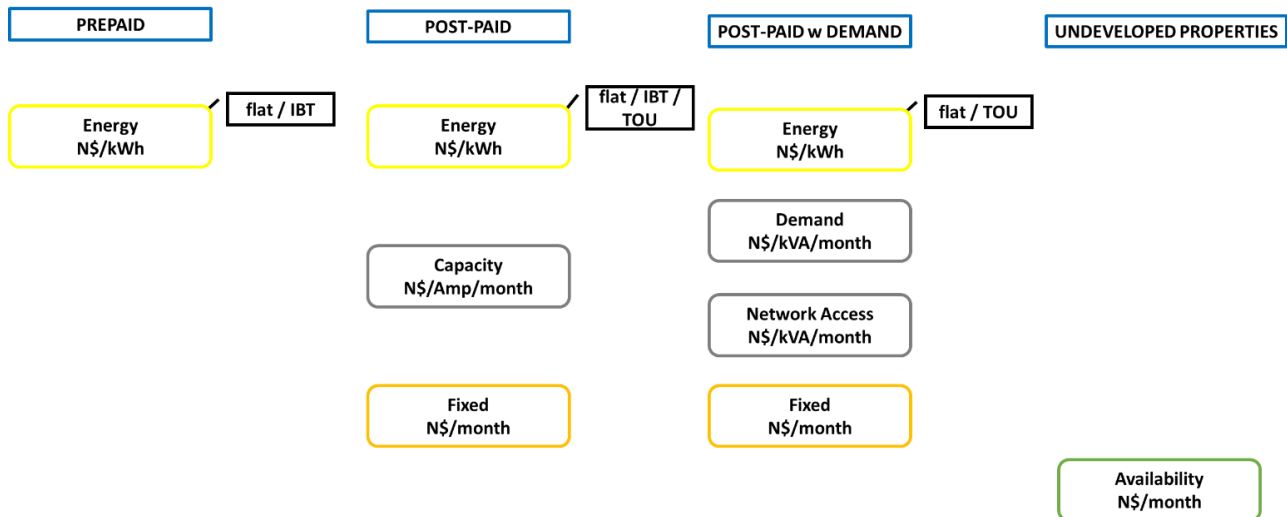
This leaves the EDI in a conundrum which necessitates guidance from the policy maker so that a common position can be elaborated which finds a balance between customers wishing to use self-generation while protecting the electricity grid that remains a key national asset.

The ECB will facilitate a process to give clear guidance on this matter to the EDI.

3.4 Allocation of Charge Types to Connection Categories

Figure 2 depicts how the various charge types are allocated to the connection categories as are used by most distribution licensees in Namibia. There is, however, a need to further align these charge structures across the EDI, in accordance with the overarching tariff objectives.

Figure 2: Allocation of charge types to connection categories



3.5 Cost Allocation Approaches

The allocation of costs across customer categories is of critical importance in the development of cost reflective tariffs. Data to inform the cost allocation process is limited to three main cost drivers, namely sales quantities (energy), customer capacity (in terms of installed capacity, measured MD and estimated ADMD) and the number of connections served.

3.5.1 Allocation Principles

The method used to allocate costs to charges is critical in determining the cost reflective level of charges for each connection category. One approach entails an allocation by determining the charge type that conveys the most direct cost signal regarding a given cost item to the customer. To illustrate: the cost of generating energy should be recovered through energy charges and losses. Applying the same reasoning, customer service costs should be recovered through monthly fixed charges per connection, since these costs are related neither to energy consumed nor to capacity made available.

However, one also needs to consider other factors beyond the desire to recover costs in the most appropriate manner, especially in an era where self-generation and customer-installed storage are becoming cost-competitive with grid-supplied electricity. This is as high fixed monthly charges may encourage customers to defect from the grid because the customer cannot escape these at all. Also, high capacity charges may encourage customers to reduce their need for grid capacity and may further incentivise grid defection. Similarly, high energy charges encourage customers to seek alternatives, for example by investing in their own generation plant.

As stated before, energy charges should only reflect generation cost and losses. All other costs should be recovered through fixed and capacity charges, leaving the question of how these costs are to be apportioned between fixed and capacity charges. It is noted that fixed charges are completely non-escapable while capacity charges provide the customer with options to reduce capacity and therefore cost.

From the licensee perspective, the application of fixed charges implies that the distributor has no revenue risk (except for grid defection). On the other hand, the use of capacity charges

implies that the risk is shared between the licensee and the customer. With energy charges, the risk remains completely with the licensee.

In the case of MD charges, risk sharing is modified if the licensee applies a minimum demand charge rule such as the “70% clause”, which implies that a customer is charged at least 70% of notified maximum demand even if the measured demand is less. This turns the maximum demand (capacity) charge into a charge that is almost like a fixed charge. Similarly, if network access charges are significant when compared to demand charges, the same applies. Therefore, balancing MD and network access charges necessitates a licensee’s careful consideration.

The principle that is applied in the following sections is that fixed monthly charges are to be limited to what can be considered “reasonable levels”, while allocating costs beyond this level to capacity charges. It is emphasised that this allocation approach should not detract from the pressing need to contain all costs, to reduce the total price of electricity, which is another critically important aspect in keeping customers on the grid.

3.5.2 Allocating Costs to Cost Drivers

The first question to ask in the cost allocation process is which of the principal cost drivers, i.e. sales, capacity/demand and connections, is best used to allocate costs to.

Table 1 summarises how the allocation of costs has been determined in the National Distribution Tariff Study 2018/19. Should a licensee wish to deviate from this allocation approach, the intention to do so must be discussed and agreed to with the ECB before it is implemented.

Table 1: Allocation of costs to cost drivers

Allocation of Cost	Key Driver
Cost of Sales - energy	Energy
Cost of Sales - other	Capacity
Employee Costs	Capacity
Operating and Maintenance Costs	Capacity
Customer Services Costs	Energy
Overheads Costs	Connections
Special Costs	Capacity
Depreciation of Assets	Capacity
Return on Assets	Capacity
Return on Working Capital	Connections
Bad Debts	Connections
Less: Other Income	Capacity
Less: Revenue from Special Services	Capacity
Reconciliation amount	Energy
Nett NEF and ECB Levies	Energy
LA Surcharge	Energy

3.5.3 Determination of Capacity to be used for Capacity Cost Allocation

The National Distribution Tariff Study 2018/19 used estimated ADMD figures to allocate capacity-related costs to connection categories. Table 2 illustrates the ADMD estimates that were used for the 20 licensees that were considered in the Study.

Licensees are encouraged to use the ADMD estimates as provided in Table 2 until their own estimates have been made. Should a licensee wish to use ADMD values other than those in Table 2, the intention to do so must be discussed and agreed to with the ECB before these are used.

Table 2: Estimated ADMD per connection per category and licensee, in kVA

Licensee	ADMD TABLE (kVA)					
	Residential	Social	General	General Demand	Institutional	Institutional Demand
NORED	0.60	0.60	4.50	20.00		
OPE	1.00	0.60	5.00	30.00	5.00	20.00
CENORED	0.90	0.75	5.00	30.00	5.00	20.00
ERONGORED	1.75	1.25	5.00	70.00	5.00	20.00
WINDHOEK	1.00	0.75	10.00	70.00	5.00	30.00
NAMPOWER	1.50	0.00	10.00	150.00	0.00	0.00
OKAHANDJA	1.25	0.75	5.00	35.00	5.00	20.00
GOBABIS	0.40	0.30	3.00	8.00		
REHOBOTH	0.75	0.75	4.00	10.00		
MARIENTAL	0.75		4.00	20.00		
KEETMANSHOOP	0.80		5.00	30.00	5.00	
LUDERITZ	0.95	0.75	5.00	20.00	5.00	
ROSHSKOR	1.50	1.00	5.00	25.00	5.00	
LEONARDVILLE	0.50		5.00			
GOCHAS	0.20		4.00	10.00	1.00	
KALKRAND	0.50		4.00			
NAUKLUFT			13.00	35.00		
HARDAP	0.25		2.00	5.00		
OMAHEKERC	0.50	0.25	2.00	0.00	4.00	15.00
FINCKENSTEIN	2.75		4.00			
ESTIMATED GLOBAL AVERAGE	1.00	0.75	5.00	55.00	5.00	40.00

3.6 Charges for Embedded Generators

In preparation for the updated National Electricity Market Framework it is necessary to devise a mechanism for how licensed generators connected to the distribution system are to be charged for using the distribution network. The principle to be applied in this case is that the generator must pay for the services it uses. A double-recovery of costs is not allowed as will be further aligned with the Market Framework as is currently developed by the ECB.

The following approaches are to be applied:

Energy charge – Energy provided by the distributor to a generator (e.g. for own consumption while the generator is not running) is to be charged at the distributor's normal energy tariff as applies to the specific connection size of the generator.

An embedded generator wheeling electricity to a customer that is not connected to the same distribution network will have to pay for losses on the distribution system. The losses will be calculated at the bulk supply tariff and not exceeding the percentage of losses allowed by the ECB for the licensed distributor.

Fixed monthly charge – In principle, a generator connected to the distribution system should be subjected to the same monthly fixed charge as is applicable to general demand connections. If the administration of the generator's connection requires significant effort above that of normal consumptive general demand connections, a licensee may determine a cost reflective additional monthly fixed charge to cover such additional administrative costs. Such charge must be presented to and approved by the ECB before it is implemented.

Capacity charge – For licensed generators supplying customers not connected to the same distribution network the distributor's standard consumptive capacity charge must be interrogated, whether it includes any provision for generation capacity passed through from NamPower as part of the transmission (maximum demand and network access) charges. If the NamPower capacity cost does include generation capacity costs (as determined by the regulator), this generation capacity component must be removed from the capacity charge applied to the embedded generator. Capacity charges should not be applied to licensed generators selling exclusively to customers located on the same distribution network since the capacity is already being paid for by the customer. This is to be verified and aligned with the Market Framework that is currently being developed by the ECB.

Local Authority Surcharge (LAS) – Licensed generators connected to a distributor's network and selling to customers on the same network must charge these customers the same LAS rate as would be applicable to energy supplied by the distributor and pay such LAS over to the local authority on a monthly basis.

Connection charge – If NamPower levies any additional charges on the distributor in relation to the connection of an embedded generator, such charges must be recovered from the generator causing them. The generator must furthermore pay connection charges to the distributor as provided for in the National Connection Charge Policy.

Also, a distributor's standard capacity-related charges must be applied to a generator to have it pay its share of the distribution network's fixed and operating costs, as well as the distributor's transmission connection cost if the generator sells energy via the transmission network.

If a licensee's charges for load customers are significantly non-reflective of actual costs incurred, a licensee may apply to the ECB to have more cost reflective charges approved, to be applied to embedded generators instead of the standard load customer charges, to ensure that such entities are charged reasonable and economically efficient tariffs.

3.7 **Pre- and Post-paid Tariffs**

This section summarises the main aspects related to pre- and post-paid tariffs.

3.7.1 **Introduction**

Most smaller electricity end-users have the option to choose either pre- or post-paid tariffs. Prepaid tariffs usually comprise of an energy charge only, designed to cover both the energy and fixed costs attributable to an end-user's average consumption. Post-paid tariffs usually have more complex charge structures than prepaid tariffs. Often, these include a combination of energy charges (which are lower than prepaid energy charges), fixed charges and capacity charges.

Originally, prepaid tariffs aimed to serve end-users with low average electricity consumption to more readily enable them to keep track of their consumption and associated expenditure.

Today, however, prepaid tariffs have become ubiquitous, especially in the case of residential connections.

Phase 1 of the National Distribution Tariff Study 2018/19 has shown that the cross-over points of many residential pre- and post-paid tariffs are rather high. The cross-over point between pre- and post-paid tariffs is the point (expressed in kWh/month) at which the total cost for electricity services is the same, irrespective of whether an end-user is served by a pre- or post-paid connection. This threshold value is readily calculated by dividing the monthly fixed and capacity charge(s) of the post-paid option(s) by the difference between the energy charge of the pre- and post-paid tariff. This assumes that the prepaid energy rate is higher than the post-paid energy rate, which should be the case since the prepaid energy rate generally includes provisions for fixed costs, which are generally not included in the energy charge of post-paid tariffs.

If the cross-over point between pre- and post-paid tariffs is set incorrectly, it sends incorrect tariff signals to customers, and disallows end-users to make a rational choice regarding these tariff options, which is undesirable.

3.7.2 Objectives for Prepaid Connections

This section elaborates the objectives that underpin prepaid connections.

3.7.2.1 Residential End-Users

For **residential end-users on prepaid tariffs**, the following objectives are important:

- Enable end-users to optimally manage their personal electricity consumption and associated expenditure;
- Provide 24/7/365 electricity purchase options to allow end-users to pay for electricity whenever needed;
- Provide a simple tariff that is readily understood by end-users, including those having a limited technical background; and
- Reduce the risk of end-users accumulating debt due to uncontrolled consumption.

The national average consumption of residential end-users on prepaid connections amounts to some 290kWh/month. Keeping in mind that prepaid tariffs consisting of an energy charge only are not cost reflective, it is argued that the cross-over point between pre- and post-paid tariffs should be set low, to ensure that end-users consuming more than a set monthly consumption level pay for the full cost of the services they use.

An important additional argument to consider when determining the cross-over point is the capacity of the current limiter that is used. The smaller the capacity of the current limiter, the smaller is the potential use of the network. This creates opportunities to introduce prepaid (energy-only) tariffs that are related to the maximum capacity of the electrical connection. In this way, and in harmony with NEST, prepaid tariffs for a 20Amp connection would be lower than those for a 40Amp, which in turn would be lower than those for a 60Amp connection, which ensures that end-users requiring a large current limiter are paying more for services than those who only need a basic connection.

When prepaid connections are offered at the same current limiter capacity than post-paid connections, setting the correct cross-over point is particularly important. To illustrate: using Windhoek's tariffs for 2018/19: using a 25Amp current limiter and based on a prepaid (post-paid) energy charge of N\$2.05/kWh (N\$1.44/kWh), and a monthly post-paid capacity charge

of N\$9.6/Amp/month, implies a cross-over point at 393kWh/month. When increasing the current limiter size to 40Amp (60Amp) moves the cross-over point to 630kWh/month (944kWh/month).

Based on the above, it is evident that the cross-over points are considerably above the average monthly consumption of residential end-users on prepaid connections, i.e. 290kWh/month. Therefore, lowering the cross-over point to more sensible thresholds requires the re-adjustment of tariffs, most likely across several years, to limit price shocks to end-users.

To balance pragmatism with the need to keep tariffs as cost reflective as possible, one could, for example, limit the maximum available current via residential prepaid connections to 30Amp, and offer residential post-paid connections between 40Amp and 80Amp. This would continue to enable residential access to basic electricity services on prepaid connections, while placing residential end-users who have higher power requirements and/or wish to benefit from net metering onto post-paid connections. Also, preferential prepaid tariffs for residential end-users, such as those under NEST as well as other social and subsidised tariffs should continue to be offered on a low ampere capacity limit only, for example not exceeding 20Amp, which ensures that subsidies can be applied with greater focus and only benefit those that are eligible to receive them.

3.7.2.2 Commercial/General End-Users

For **commercial/general end-users on prepaid tariffs**, the following objectives are important:

- Enable end-users to optimally manage their electricity consumption and associated expenditure;
- Provide relief from fixed charges (fixed, capacity) for customers with low consumption;
- Encourage the productive use of electricity by fostering the development of small- and medium enterprises;
- Reduce the risk of accumulating consumer debt; and
- Provide 24/7/365 electricity purchase options to allow end-users to pay for electricity whenever needed.

Based on the above objectives, prepaid connections for commercial/general users are predominantly aimed to advance small businesses that are characterised by low electricity consumption. This implies that the cross-over point between pre- and post-paid connections is best set at a level that enables "low-consuming" businesses to start their operations. Target end-users would therefore predominately be small as well as start-up enterprises. For general users, the cross-over point is more difficult to determine, as the use of electricity in businesses is much more diverse than in the case of residential end-users.

Setting the correct cross-over point can once again be informed by the average consumption from within the relevant end-user group(s). From the analysis of the 20 licensees included in the National Distribution Tariff Study 2018/19, the average monthly electricity consumption of end-users using a general connection amounts to some 1 750kWh/month. This is an empirical finding, based on the consumptive behaviour of many Namibian commercial/general end-users. It could be argued that a sensible cross-over point between pre- and post-paid commercial/general end-user tariffs should therefore not be higher than what is currently evident in the market. In the absence of economic guidelines into the electricity needs of small and emerging enterprises, the cross-over point is to be set around the average consumption of general connections which ensures that - on average - the choice between pre- and post-paid connections is revenue-neutral for licensees.

3.7.3 Guidelines for the Application of Prepaid Tariffs

In specific settings, the ECB may prescribe certain tariff/metering types. This is already practiced, for example in the case of the NEST, which are only offered via prepaid meters.

Generally, prepaid tariffs are to be offered to

- a. residential (social) connections benefitting from NEST;
- b. low-consumption single-phase residential and commercial/general end-users, provided that the cross-over point to post-paid tariffs is judiciously set;
- c. general end-users characterised by low load factor, while requiring a sizeable current limiter, as is for example used by community services including for sports field lighting, churches and similar end-users having an irregular demand for electricity; and
- d. temporary connections (up to 3x100 Ampere or maximum prepaid meter current limiter capacity, whichever is lower), as is for example used at temporary construction sites.

3.8 “Other Charges”

The so-called “other charges” include service charges, administrative as well as penalty charges for services that are not directly related to the fixed, capacity and energy costs of active connections.

The income that a licensee derives from these “other charges” is deducted from the revenue requirement before fixed, capacity and energy charges are determined.

3.8.1 Schedule of “Other Charges”

Table 3 provides a description of the charge categories that are used for “other charges”, while Table 4 provides a summary of standard “other charges”.

Table 3: Description of the various charge categories used for “other charges”

Charge Category	Description
Service	A service provided to customers or prospective customers. In principle such service charges should be based on estimated or average cost of providing such service. Licensees should maintain a motivation for the costs included in each such service charge.
Penalty	A penalty charge to customers is usually based on the cost of dealing with customer non-compliance or breach of contract. In principle, such penalties are cost based, and licensees should motivate why such costs are included in each such penalty charge.
Penalty fee	A penalty fee may be charged in case of serious customer or contractor non-compliance, or violation of safety regulations. Penalty fees are normally set at a level intended to deter customers from taking certain actions, such as illegal wiring or tampering with installations, which have safety and/or financial implications.
Connection fees	Connection fees are intended to cover the cost of providing the connection assets (materials, labour, transport etc), and are regulated under the National Connection Charge Policy and must comply with it.

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Table 4: Summary of standard "other charges"

Fee Type	Fee Category	Cost driven	Description
Administrative			
Administrative	Penalty fee	no	Unblocking prepaid account, interest on late payment
Administrative	Service	no	Replacement and reversal of prepaid tokens, clearance certificates
Administrative	Penalty	yes	RD cheques
Contractor registration	Service	yes	Service fee for contractor registration
Contractor penalty	Penalty	no	Penalty fees for contractor non-compliance
Connection, Disconnection, Reconnection			
Call out	Service	yes	Call-out due to customer installation faults
Connection	Capital cost	yes	Connection charges to defray connection capital costs
Connection	Service	yes	Connection charges to defray connection administrative costs
Disconnection	Service	yes	Service fee for voluntary disconnection
Disconnection	Penalty	yes	Cost for disconnection due to customer non-compliance
Disconnection	Penalty fee	no	Penalty for disconnection due to customer non-compliance
Installation test	Service	yes	Service fee for customer installation test
Reconnection	Penalty	yes	Penalty for reconnection after customer non-compliance
Reconnection	Service	yes	Service fee for reconnection after voluntary disconnection
Relocation	Service	yes	Service fee for relocating prepaid meter to another premises
Metering and Current Limiter Tests and Changes			
Current limiter change	Service	yes	Service fee for changing a customer current limiter
Current limiter test	Service	yes	Service fee for testing a customer current limiter
Meter reading	Service	yes	Service fee for special meter reading on customer request
Meter replacement	Service	yes	Service fee for meter replacement on customer request
Meter replacement	Penalty	yes	Penalty fee for meter replacement due to customer tampering
Meter test	Service	yes	Service fee for meter testing
Penalties			
Tampering penalty	Penalty fee	no	Penalty fee for tampering
Damage cost	Penalty	yes	Recovery of cost to repair customer caused damage
Damage penalty	Penalty	no	Penalty fee for damaging licensee infrastructure
Illegal wiring	Penalty	no	Penalty for customer illegal wiring
Late payment fee	Penalty	no	Penalty for late payment of account
Meter Tampering	Penalty fee	no	Penalty fee for meter tampering by customer

All other charges that licensees are to apply must be classified using the standard structure of "other charges" as shown in Table 4. Charges that do not need to be approved by the ECB must be omitted from the schedule of approved "other charges" prepared by licensees, to avoid creating the impression that such charges are regulated and/or approved by the ECB.

Account deposits required to be paid by customers must also be stated on the schedule of approved other charges of the licensee, as per applicable rules.

3.9 Guidelines for General Tariff Changes and Customer Impact Analyses

Tariffs are generally modelled in the ORM as weighted averages of a connection category. Customer impacts are therefore calculated on charge averages that do not reflect the actual impact that tariffs have on individual customers. Actual individual impacts may be quite different from the average, based on the tariff structure, tariff rate changes implemented and the customer's load factor.

Licensee are therefore encouraged to

- Model proposed tariff changes on individual customers using their billing and vending system data, and to establish statistics on how individual customers will be affected. This should guide the licensee in its customer outreach and information efforts, and to inform customers on the impact that tariff changes have on the end-user's total electricity bill. For connection categories with few customers it may be possible for a

licensee to inform individual customers of expected impacts and counsel them regarding possible actions that can be taken to reduce the overall impacts.

- Encourage customers to use energy efficient appliances, and how to best respond to specific pricing signals conveyed via the tariffs;
- Advise customers having special (higher) tariffs (such as the rural MV customer groups) on the rationale for applying special tariffs to them and explore steps to reduce or mitigate the costs that underly the higher tariffs;
- Consider how to best achieve a balance between the use of cost reflective tariffs versus social, economic, customer impacts and the complexity of tariffs. The ORM-TD includes numerous indicators (in the form of % change) for individual tariff rates, sales volume changes, load factors and overall tariff changes that should guide the licensee in balancing the above aspects.

3.10 Special Considerations Regarding Inputs in the ORM

3.10.1 Requirements of Network Assets above 33kV

Assets above 33kV are not valued using the NENA asset register because they are often individualised and can therefore not be reasonably valued using the NENA categorisation approach. The following requirements apply to asset registers developed by licensees for assets above 33kV:

Asset registers must

- differentiate by primary operating voltage;
- separately identify, quantify and value overhead versus underground assets;
- separately identify, quantify and value line/cable assets (length denominated) versus transformation assets (capacity to be denominated in kVA) versus other assets not falling into the previous two categories;
- record and report network lengths and transformation capacities;
- separately show the assets added between formal valuations and external asset valuations; and
- report recently added assets in terms of actual installation cost.

Asset valuations must be based on periodic professional valuations undertaken by external entities, and summary reports must be submitted to the ECB as supporting evidence.

3.10.2 Special Cost Items and Exclusions from the Cost Base

The following rules apply to specific cost items that may appear in a licensee's operating budget:

- Interest on long-term loans taken up for the funding of the licensee's assets is not allowed as part of interest costs claimed in the operating budget as such interest is included in the rate of return allowed on assets. Licensee are therefore required to split interest charges claimed between short-term loans (not related to fixed assets, such as overdraft facilities) and long-term loans (related to assets). The ECB may request the licensee to submit a detailed schedule showing how the claimed interest costs arose.
- Social responsibility investments and similar discretionary expenses cannot be recovered in the regulated cost base and must be paid from a licensee's profits.

- Consultancy costs associated with engineering and architectural design, supervision and project management related to the creation of assets is not allowed in the cost base. Such consultancy costs must be capitalised with the relevant asset and will be allowed depreciation and return unless grant/customer funded.

3.10.3 Local Authority Surcharge (LAS)

The Local Authority Surcharge (LAS) was introduced by the ECB to compensate local authorities (including regional councils) joining a Regional Electricity Distributor (RED) for the loss of income derived from the sale of electricity prior to joining a RED. The LAS is an allowable part of the revenue requirement of a licensee and is either included in the tariff charges of the licensee or shown as a separate charge.

The ORM includes the LAS as a line item in the Revenue Requirement sheet. It is not included in any other cost schedule, irrespective of whether the licensee refers to it as the LAS, "royalties", "interest on investment", or using any other name.

It is to be noted that all and any payments to local authorities or regional councils – over and above the shareholder dividends or in terms of service agreements where the local authority provides services to a licensee – are recognised as LAS, and must as such be reflected in the Revenue Requirement schedule as the LAS, irrespective of the name and/or rationale that a licensee may use/have for such an expenditure.

3.10.4 Grant/Customer Funded Assets

Grant- and/or customer-funded assets are a licensee's fixed assets that were funded by any means other than from own resources. Licensees may only earn a regulated return on assets if these have not been funded by grants and/or customers. In other words, the tariff methodology does not allow a licensee to earn a return on any grant- or customer-funded assets, as this would result in the double-recovery of costs. In this context, grant-funded assets are those that have been "donated" to a licensee, for example by way of a donation by the Government or from donors.

Given the above it is necessary that all licensees identify and account for all customer- and/or grant-funded assets. Often, and particularly in the case of older assets where records are unavailable, it is not practically possible to fully account for such assets. In such cases, the ECB in collaboration with licensees will determine a reasonable percentage of such grant- and customer-funded assets which is to be used in the return calculation.

Similarly, the tariff methodology does not allow depreciation charges to be raised for customer- and/or grant-funded assets, using the same rationale as this would constitute a double dipping at the expense of customers.

Extending the above rationale implies that income from connection fees charged to cover the capital cost of assets must not be included in "other revenue" as deducted from the revenue requirement. In this context it is noted that the ECB has in the past allowed a compromise on this matter, by allowing licensees to claim depreciation on such assets while including all connection fees in "other revenue".

3.10.5 Ampere Capacity Rating and Charge Denomination

The ORM denominates Ampere-based capacity charges and connection capacities in the form of summated capacities. To illustrate: a three-phase 40Amp connection is recognised as

a 120Amp connection, and the corresponding tariff rate is expressed as charge per summated Amp rating. This implies that tariffs for single- and multi-phase connections of the same category should be the same.

Licensees using nominal Ampere ratings must therefore ensure that multi-phase Amp-rated connections are correctly converted to obtain the summated total Amp rating as required in the ORM. Licensees may express tariffs using nominal capacity ratings and converted tariffs as applicable to such ratings, provided that adequate information is availed to enable customers to understand the difference between nominal and summated Amp ratings and associated tariffs.

4. Part B: ORM – Tariff Determination

4.1 Purpose

The purpose of the ORM – Tariff Determination (ORM-TD) is to

- a) calculate a licensee's revenue requirement for a specific financial year; and
- b) determine a licensee's tariffs and resulting revenues for a given financial year, in alignment with the revenue requirement and the rules as summarised in this rulebook.

The ORM-TD is an Excel workbook that is provided by the ECB.

4.2 Process

Each year, the ECB updates each licensee's ORM-TD workbook before making it available to licensees for completion. Such inputs by the regulator include the previous financial year's approved budget and tariffs, as well as the approved weighted average cost of capital (WACC) for the previous and next year. Alternatively, the ECB may require the licensee to complete the ORM-TD with the approved information. In either case the ECB will check the ORM-TD on submission by the licensee for correct insertion of previous year approved figures.

The ORM-TD Excel workbook contains schedules that must be completed by a licensee. These capture the licensee's

- a) Power purchase costs;
- b) operating budget, including cost and other revenue items;
- c) asset summary; and
- d) projected sales.

Based on above inputs, the ORM-TD is used by the licensee to determine a licensee's

- a) detailed tariffs; and
- b) performs select analyses which are of use to the licensee as well as the ECB.

Once approved by the ECB, the ORM-TD workbook captures the licensee's approved revenue requirement as well as the approved tariffs for a given financial year.

4.3 Definitions

A "licensee", as referred to throughout this document, means

- a licensee's *entire* operations and organisation where the licensee is a dedicated electricity distribution and supply entity (such as a RED or fully commercialised and legally separated stand-alone electricity distribution entity); or
- only the ring-fenced electricity distribution and supply portion of an organisation that has an embedded electricity distribution and supply operation but also undertakes other activities (such as a local authority or regional council).

4.4 Conventions

The ORM-TD workbook uses colour coding to indicate items that must be entered by a licensee, inputs that are provided by the ECB, as well as cells that contain formulas to calculate results. Licensees are not authorised to add, amend or input data in any fields marked for ECB entry. Worksheet "Conv" provides the colour codes used throughout the ORM-TD.

The format of worksheets in the ORM-TD workbook are mostly fixed, and licensees may not add rows or columns to most sheets contained in the workbook. A notable exception to this is worksheet 'B1.0 Budget Input' where as many rows as may be needed to accommodate a licensee's detailed operating budget may be added.

For organisations having a ring-fenced electricity distribution and supply entity, the following applies (amongst others):

- Staff numbers (full time) only refers to staff required for licensed electricity-related activities;
- Staff cost (part time) refers to staff costs of other departments recovered from electricity;
- Budget refers to the budget of the ring-fenced electricity distribution entity only;
- Assets refer to dedicated assets used as part of licensed activities only;
- All shared costs accounted for in budgets other than the dedicated budget for licensed activities are to be recovered following the ECB's Ring-Fencing Guidelines, and must be supported by detailed documentary evidence submitted with the licensee's ORM-TD;
- The ECB will not accept any lump sum cost items such as "administrative charges" or "support service costs" unless they are supported by detailed schedules indicating the types of cost items and respective budgets included in such "lumped" amounts.

4.5 Populating the ORM-TD

Licensee's should populate the ORM-TD workbook using the following sequence of steps:

- a) Ensure that the ORM-TD Excel workbook is the latest version that has been received from the ECB, and is for the new financial year;
- b) Insert the required information in the sheet "A1.1 General" (all ECB approved numbers should be obtained from the ECB);
- c) Insert the operating budget and link it to the ORM standard cost items;
- d) Insert the asset data and working capital data as well as bad debt data;
- e) Insert the power purchases and associated tariffs;
- f) Review the resulting draft revenue requirement, and comparing it to the previous financial year's approved revenue requirement;
- g) Adjust the budget where excessive cost increases are indicated (unless these can be fully motivated);
- h) Prepare a sales volume forecast (based on the projected sales volumes for the current year), while considering volume change percentages as well as load factor changes (revenue schedule and dashboard);
- i) Review the alignment of the projected sales volume with projected power purchase volumes using the losses schedule;

- j) Design the new draft tariff rates to meet (or at least not materially exceed) the draft revenue requirement;
- k) Review the proposed draft tariff rates against the indicative tariffs calculated in the Indicative Tariffs schedule after adjusting the ADMD estimates in the indicative tariff schedule, to reasonably align with the projected capacity purchases;
- l) Ensure that the proposed tariff rates and prepaid to post-paid cross-over points move closer to cost reflective values by comparing them to the previous year's ORM; and
- m) Review the customer impacts resulting from the proposed draft tariff rates (on the revenue schedule as well as the dashboard) to ensure that price changes per connection category remain within reasonable limits.

Should the projected draft revenue lead to an under-recovery (when compared to the draft revenue requirement), the licensee must review all cost items comprising the revenue requirement and reduce excessive costs where possible. If an under-recovering tariff application is submitted to the regulator, the ECB may reduce tariffs in alignment with regulatory budget reductions. This approach is aimed to discourage licensees from submitting inflated budgets.

The following input discipline is of critical importance:

- Cells marked for licensee input are the **responsibility of the licensee** to populate; and
- Cell marked for ECB input may **only contain ECB approved** input, i.e. input to these cells will either be made by ECB staff or by the licensee using official ECB approved data only.

4.6 **EPM Sheets**

The name 'EPM' refers to the ECB's regulatory database system. Two EPM sheets are included in the ORM workbook, capturing tariff and sales volume data from the ORM's sales schedule in a standard format that can be read by the EPM software, to generate the schedules of approved tariffs.

The worksheet named 'EPM' feeds the ORM's indicative tariff calculation sheet with tariff and sales data. A second EPM sheet, named 'EPM-P', contains the previous year's data. Both EPM sheets must contain valid and properly linked data, and they have the following main requirements:

- The format of the EPM sheets (in terms of columns and starting row of data) may not be modified by the licensee in any way;
- The standard and special connection categories allowed in the Sales Schedule are all pre-linked into the EPM sheet and should not require additions or amendments by licensees;
- Licensees wishing to publish area-differentiated tariff schedules (i.e. REDs that offer area-differentiated tariffs) may add additional rows to the EPM sheet above the row highlighted in red. Licensees using this option must ensure that:
 - All tariff and sales volume data for all connection categories and areas must be correctly linked in the EPM sheet;
 - All calculations and lookup columns of the EPM sheet are properly populated with formulae and data using the same approach as applied in the existing pre-populated rows;

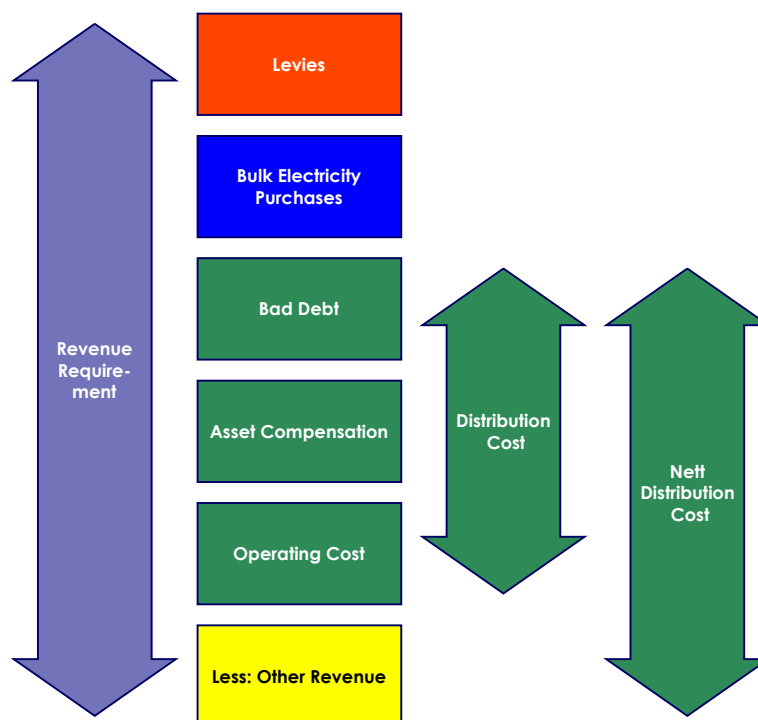
- Conversions of units between the Sales Schedule and the EPM sheet are correctly implemented (e.g. MWh to kWh, Ampere to summated Ampere);
- Where the LAS is included in tariffs in the Sales Schedule, it must be deducted from such tariffs in the EPM sheet, and the LAS must be captured in the LAS column;
- The total revenue calculated in the EPM sheet must correspond to the total revenue calculated in the Sales Schedule.

NOTE: If the above requirements have not been complied with the ECB will return the ORM-TD workbook to the licensee, for correction by the licensee, before the tariff application is considered any further.

4.7 Revenue Requirement

The approach to determine electricity tariffs – as laid down in the National Tariff Study (2001) and National Distribution Tariff Study for Namibia (2018/2019) – rests on determining a licensee's approved revenue requirement, which includes allowable costs plus a regulated return on assets. Figure 3 depicts the components of a licensee's revenue requirement. The ORM-TD schedules capture the inputs to calculate the components of the revenue requirement.

Figure 3: Composition of the Revenue Requirement

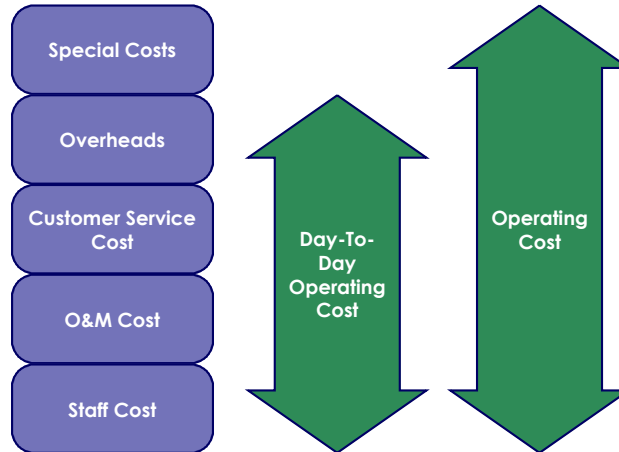


A distribution licensee's core business rests on owning and operating an electricity distribution system. Statutory levies and bulk electricity purchases are cost items arising outside the actual distribution business and are therefore not under the direct day-to-day control of a licensee.

Operating costs, asset-related costs, bad debts and other revenues are at the core of a distribution licensee's business, and the total of these cost items are referred to as net distribution cost. It includes the regulated compensation allowance for assets (i.e. depreciation of assets and a regulated return on assets). Bad debt is a cost item not directly associated with

the day-to-day operations of the licensee, and is therefore treated separately, while the “other revenue” is accounted for as reducing the overall tariff revenue requirement of the licensee, since other revenues do not need to be recovered from a licensee's normal tariffs. The remainder of the revenue requirement is referred to as the “operating cost” of the licensee, which is focussed on cost items directly related to the operation of a distribution licensee's business and fully controllable by the licensee, refer to Figure 4.

Figure 4: Composition of the Operating Cost



4.8 Tariff Determination Schedules

The following sections explain the individual sheets contained in the ORM-TD.

4.8.1 Conventions

This sheet

- specifies the key to the colour codes used throughout the ORM; and
- provides a code generator for connection categories that is to be used to generate valid category codes, as used in Schedule “A1.2 Sales” to identify non-standard connection categories.

To generate a connection category code, select each of the seven determinants and then copy the resulting code and paste into the relevant code cell on the sales sheet.

4.8.2 Schedule A1.1 General

This sheet

- identifies the licensee as well as the name and telephone number of the licensee's contact person;
- specifies the year(s) to which the ORM applies;
- specifies the licensee's staff numbers;
- calculates the licensee's recommended discount percentage on capacity/maximum demand/network access charges for MV connected customers;

- provides the capacity limit rules for common connection categories and specifies whether the charges for a multi-phase Ampere capacity connection are based on nominal or summated capacities ³; and
- specifies the WACC, statutory levy rates and maximum bad debt percentage as provided by the ECB.

Regarding a licensee's staff numbers, the following inputs are needed:

- total number of positions budgeted for in the ORM staff budget including filled positions and to-be-filled vacancies included in the budget; and
- total number of staff members employed by the licensee at the time of completion of the ORM;
- total number of vacant positions in the approved organisational structure of the licensee at time of completion of the ORM.

4.8.3 Schedule A1.2 Sales

This sheet captures the connection categories used by the licensee, the tariff charges for the different connection categories, the projected sales volumes of each connection category and revenues associated with such tariffs.

Regarding the connection categories, this worksheet includes two main sections, i.e.

- Section 1 that contains standard, pre-defined connection categories which the licensee cannot alter. These include all common variants of the six standard connection categories used and should therefore constitute the majority of the licensee's customer base and revenue; and
- Section 2 that contains the "special categories" that are offered and that must be populated by the licensee. Each such connection category must be appropriately named and classified using a valid connection category code as can be generated on the "A1.0 Conventions" sheet.

The following guidelines apply when populating the "**Tariff Rates**" portion of the schedule:

- present year tariffs are the last ECB-approved rates as per the schedule of approved tariffs;
- capacity (per Ampere) tariffs are entered in terms of **summated capacity**, irrespective of whether the licensee publishes these in nominal or summated terms;
- fixed tariffs are entered in N\$/connection/month;
- capacity tariff rates are entered in N\$/Ampere/month;
- energy tariff rates are entered in c/kWh;
- maximum demand and network access tariffs are entered in N\$/kVA/month (or N\$/kW/month for those categories that still use kW instead of kVA); and
- The next year's tariff rates (i.e. the tariffs that are being applied for) must:
 - comply with the provisions and directives contained in this rulebook;
 - comply with all instructions and/or directives issued by the ECB to the licensee;

³ Nominal capacity means that a three phase 40 Ampere connection is billed as 40 Ampere, while summated capacity means that a three-phase 40 Ampere connection is billed as 120 Ampere.

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- result in a projected total revenue that does not materially exceed the revenue requirement that is applied for;
- demonstrably move towards the relevant indicative tariff rates as indicated in the indicative tariff computation sheet (refer to Schedule "C1.2 Indic"), where applicable; while
- tariffs for special connection categories should align with rates for standard categories where applicable, and all deviations must be motivated and justified by the licensee.

The following guidelines apply when populating the "**Sales Volume**" portion of the schedule:

- the licensee must populate the sales volumes for all connection categories for the present year (forecast for the year based on the most recent available actual sales data) and the projected sales volumes for the next year;
- installed Ampere capacity must be completed for all connection categories, **including prepaid connections** and other connections where no capacity charges are levied (except for demand metered connections where the maximum demand data must be completed);
- installed Ampere capacity for multi-phase connections must be expressed in terms of **summed** Ampere ratings;
- accurate connection numbers must be completed for all connection categories, **including** for prepaid connections and other connection categories where no fixed charges are levied;
- IBT and TOU energy sales must be completed on the TOU and IBT Sales schedules (from where they are automatically transferred to the revenue schedule);
- all energy sales are entered in MWh;
- energy sales reported in this section must be actual energy sold by the licensee only. Special services provided by the licensee and charged on the basis of energy quantities not supplied by the licensee must be reported in the section at the bottom of the sheet, titled "Special Services";
- maximum demand and network access sales must be stated as average monthly quantities;
- energy used for streetlighting and other public service applications such as traffic lights must **not be included here unless** the licensee bills such energy to another entity which then results in revenue received by the licensee. Energy used for streetlighting and other public service applications which is not billed and/or is not resulting in revenue received by the licensee must be accounted for in Schedule "A2.2 Losses".
- energy used for the licensee's own purposes (licensee offices, workshops etc) must also be accounted for in Schedule "A2.2 Losses".

At the bottom of this sheet there is an additional section titled "Special Services" with sub-sections for tariffs, volumes and revenue. This is to be used for special cases where the licensee provides services based on quantities where the sales quantities reported are not provided by the licensee. An example of this is the envisaged reliability service charge which will be based on energy sales of an IPP. The sales quantities reported in this section are not included in the sales statistics of the licensee. The revenue derived from these special services is deducted from the revenue requirement on the Schedule "C1.1 RR".

NOTE: A licensee's failure to supply complete capacity and connection counts invalidates the indicative tariff calculation and may result in the ECB rejecting the licensee's tariff application.

Statutory levies resulting from past and projected sales are automatically calculated below the revenue schedule, using per unit rates as are provided by the ECB. The resulting amounts are carried to the "Nett NEF and ECB Levies" item in the Schedule "C1.1 RR", which summarises the licensee's revenue requirement for the next year.

4.8.4 Schedule A1.2.1 TOU Sales

This sheet contains the tariff rates and sales for TOU-based sales. The schedule deals with energy rates and sales only, noting that fixed and capacity sales are entered in Schedule "A1.2 Sales".

TOU energy rates must comply with ECB directives on their relation to TOU energy rates at which the licensee purchases energy. The default position is that TOU energy sales rates must be a constant c/kWh above the purchased TOU energy rates, i.e. all rates for all TOU time slots must have the same c/kWh difference to the purchased TOU energy rate for the same time slot.

The ECB will issue directives on how sales TOU rates are to be modified in case of non-TOU purchases.

The licensee must motivate and justify any deviations from the above rules and submit these in writing at the time when the tariff application is submitted to the ECB.

4.8.5 Schedule A1.2.2 IBT Sales

This sheet contains the IBT block sizes, the tariff rates and projected sales for IBT-based energy sales. The schedule deals with energy rates and sales only, noting that fixed and capacity sales are entered in Schedule "A1.2 Sales". IBT block sizes must be specified in kWh/month.

4.8.6 Schedule A1.2.3 Special Services

This sheet deals with "Special Services" with sub-sections for tariffs, volumes and revenue, arranged similar to "A1.2 Sales". This is to be used for special cases where the licensee provides services based on quantities where the sales quantities reported are not provided by the licensee. An example of this is the envisaged reliability service charge which will be based on energy sales of an IPP. The sales quantities reported in this section are not included in the sales statistics of the licensee. The revenue derived from these special services is deducted from the revenue requirement on the Schedule "C1.1 RR".

4.8.7 Schedule A1.2.4 TOU Special

This sheet contains provision for TOU energy denominated special services sales. Its form and function are the same as for schedule A.1.2.1.

4.8.8 Schedule A1.3: Indicative Tariff Calculation

This sheet draws on information provided in the other schedules of the ORM, using the revenue requirement to compute the licensee's indicative tariffs, as is comprehensively described in the National Distribution Tariff Study of 2018/19. The tariff calculation results in a set of indicative

cost reflective tariffs using the ECB-approved cost allocation mechanism and estimated ADMD of each connection category.

The schedule also calculates the over- / under-recovery of the actual tariffs compared to the indicative tariffs. Licensees must ensure that indicative and actual tariffs are increasingly aligned from one year to the next, thereby steadily reducing the percentage over- / under-recovery.

The schedule further calculates the desired and actual cross-over points for prepaid versus post-paid tariffs where both options are offered. The licensee must demonstrate that the cross-over point moves materially closer to the desired cross-over point from one year to the next.

The only licensee input on this sheet is the ADMD estimates for the past and next year. The ADMD estimates should result in a summated ADMD that is within 5% of the maximum demand purchased from NamPower. The balance of ADMD estimates between connection categories must not be changed substantially from one year to the next.

The licensee should ensure that as far as reasonably possible the over- and under-recovery of revenue from connection categories should either a) be reduced from year to year and/or b) be equalised between similar connection categories.

4.8.9 Schedule A1.4: Dashboard

This sheet summarises the key changes that take place in tariffs, sales volumes and revenues in moving from the current to the next financial year, based on the inputs in the various ORM schedules. The sheet is to assist the licensee and ECB to identify unexpected changes that arise by error or design, and address these where applicable.

Here, the licensee can easily see the high-level results of the proposed tariffs and projected sales volumes in terms of a) generating revenue that meets the revenue requirement, b) results in reasonable tariff impacts on the major connection categories and c) moves the tariffs closer to the desired tariff levels.

The licensee can also identify the magnitude of changes in energy sales and capacity sales volumes as well as load factors. This is intended to help the licensee identify any significant errors in capturing sales data.

4.8.10 Schedule A2.1 Purchases

This sheet captures the licensee's bulk energy and capacity purchases, including purchases from NamPower, IPPs, generation plant owned by the licensee, net metering clients and others. The schedule includes sections specifying supplier tariff rates, purchase volumes and associated costs.

The licensee must enter the tariff rates at which electricity purchases are contracted, as well as estimated and/or projected purchase quantities. For non-TOU energy purchases the same rate must be entered in all TOU time slots, and the purchased quantities must be entered in the relevant TOU time slots. **This implies that for any significant bulk purchases besides flat energy net metering, the metering arrangements must provide TOU-differentiated energy purchase quantities, even if the applicable tariff is not TOU-differentiated.** This is done to correctly calculate the overall TOU-differentiated energy purchase costs which influence the TOU energy sales tariffs.

The schedule also includes a section where ECB-allowed purchase tariffs (that may be recovered from customers) are specified by the regulator. This mechanism allows the ECB to transparently reduce tariff rates where a licensee's contracting arrangements result in rates

that exceed the NamPower-supplied alternative. Where this is the case, the ECB may reduce the allowed rates to NamPower-equivalent rates, thereby protecting the customer from ineffective power purchase contracts entered into by the licensee.

Statutory levies payable on power purchases are calculated below the purchase cost calculations, using rates provided by the ECB. The resulting amounts are carried to the "Nett NEF and ECB Levies" item in the Schedule "C1.1 RR", which summarises the licensee's revenue requirement.

NOTE: Purchases from IPPs entered on this sheet must only be energy physically taken from the IPP at the rate approved for such supply. Deemed energy payments or quantities must **not** be included on this schedule but reported in Schedule "A2.2 Losses" instead.

4.8.11 Schedule A2.2 Losses

This sheet reconciles energy sales and other legitimate energy uses with energy purchases to compute the licensee's energy losses. Such losses include both technical losses (which are a physical characteristic of all electricity networks) and non-technical losses (including electricity lost as a result of theft, illegal connections, faulty metering and/or billing problems, as well as causes not directly related to the technical characteristics of the distribution network).

The schedule uses total energy sales and purchases from the respective schedules in the workbook. The licensee must enter the energy used by streetlights (provided these are not billed and generate revenue) as well as energy used for the licensee's own operations.

Energy used by streetlights can either be metered or may be estimated using the total installed wattage of streetlights (as per the NENA asset register, as is provided to the ECB as supporting documents) multiplied by the typical daily operating hours for streetlights.

Energy used for a licensee's own operations must be metered, and a reconciliation of such metering data must be supplied to the ECB on request. Estimates of the licensee's own energy consumption are not permissible and must therefore not be entered into this schedule.

The schedule also includes a feature for the ECB to regulate the maximum allowed level of energy losses to a percentage determined by the regulator. Should the ECB choose to apply this mechanism, a reduction in the power purchase costs allowed to be recovered through the licensee's tariffs will result, thereby reducing the licensee's overall revenue requirement in a transparent manner without affecting the actual sales and energy purchase data included in the ORM. Any loss capping that is to be applied by the ECB will be discussed with the licensee.

Finally, this schedule contains a section where expected deemed energy payments to IPPs are to be captured, both the expected kWh of deemed energy as well the deemed energy payment amounts. The deemed energy payment total as well as any loss capping reductions in revenue requirement are reported on Schedule "C1.1 RR".

4.8.12 Schedule B1.0 Budget Input

This sheet captures the licensee's operating budget and links it to standard line items in the ORM. It primarily a **licensee input** sheet.

The licensee must use the schedule's first two columns for budget item descriptor(s) in the licensee's budget format, while the next two columns must contain the forecast expenditure for the current year (12-month forecast) and the proposed budget for the next year. The licensee's budget line item set-up should ideally mirror the licensee's own set-up in which

budgets are compiled, to allow for easy updating as the licensee's budget may be revised during the tariff application process.

If the sheet contains too few rows, additional rows may be inserted, provided this is done above the red indicator row bearing the following text "INSERT YOUR BUDGET ABOVE THIS ROW". Should this be required, the formulas that are used in columns E, F and G must be copied from the existing to the newly added rows.

In column F, the licensee must select the appropriate ORM cost line item for each budget line. The dropdown list provided in column F is limited to cost items that are approved by the ECB. During the licensee's application review process, the ECB reviews all cost allocations. If a licensee's budget contains costs that may not be included in the revenue requirement, such items will not be linked to any ORM line item.

NOTE: the convention used in this sheet is that all expenditures must be entered as positive numbers, while "other income" must be included in the operating budget and be entered using negative numbers. A licensee's tariff revenue budget lines as well as bulk purchases budget lines must not be included in this sheet as these are dealt with in the ORM's revenue schedule.

Below the schedule's main budget part is a special section for **consultancy budgets**. All consultancy budget line items must be captured in this special section. This section differs from the main section in that the ECB may intervene here on individual line items to reduce or disallow them, whereas for all other budget lines this activity takes place on the Schedule "B1.1 Budget".

The licensee is responsible to capture all relevant budget items in this schedule and ensure that all relevant line items are properly linked to a valid ORM standard line item. Omissions will result in such items not being included in the revenue requirement. Financial losses incurred as a result of any such omissions may not be included as reconciliation amounts in future budgets.

Line items that are validly linked with an appropriate ORM cost category automatically display a green colour in column E, all others remain red.

Column G indicates the amount carried over to the Budget Schedule.

The sum of the raw budget versus allocated items is shown at the top of the schedule, this is to assist the licensee in ensuring that all relevant budget items are captured and linked correctly.

A licensee may not add any items to the standard ORM cost line items. Where considered necessary, a licensee can approach the ECB to request that additional line items are included. Where a licensee is unsure of how a given budget item is to be linked, the ECB must be approached for clarifications.

4.8.13 Schedule B1.1 Budget

This sheet is used to examine whether the licensee's operating budget is correctly compiled and compares the budget to a) the previous year's approved budget and b) the licensee's projection for the present (previous) year using the ORM standard cost formats. It is an **ECB input** sheet.

The ECB provides the previous year's approved budget, as per that year's approved ORM.

As part of the assessment of a licensee's tariff application, the ECB reviews the licensee's proposed budget items and indicates the approved budget amount in column E. This enables the licensee to readily identify any differences between the amounts requested (column D)

and those approved by the ECB (column E), and the amount and percentage deviation (columns H and L).

The ECB will discuss any budget interventions with the licensee.

The sheet also summarises "Other revenue", which typically includes connection and re-connection fees, noting that the licensee must provide adequate information about the sources of any "other revenue". It is noted that "other revenue" is deducted from the licensee's revenue requirement that is to be recovered through the tariffs.

4.8.14 Schedule B2.1: Asset Values and Depreciation

This sheet captures the licensee's fixed asset values (book values) and associated depreciation claims. The schedule has three main parts, namely

1. **Network assets up to 33kV**, which are valued using NENA. The licensee must submit the NENA dataset and valuation result (Summary by Asset Category report) to the ECB together with the completed ORM.
2. **Network assets over 33kV**. The licensee must submit the valuation summary or asset register summary extract together with the completed ORM.
3. **Non-network assets**, as per the licensee's approved asset register. The licensee must submit the valuation summary or asset register summary extract together with the completed ORM.

The following general stipulations apply regarding **asset values**:

- value changes resulting from NENA cost updates or other re-valuations must be recorded in the "revaluation adjustment" column (column D);
- new asset additions must be recorded in the "additions" column (column E); and
- asset disposals must be recorded in the "disposals" column (column F).

Regarding the network assets, the following stipulations apply:

- NENA uses a modern equivalent replacement cost valuation approach;
- the ECB updates the unit cost rates for all NENA asset types periodically.
- the value of new NENA network assets must be recorded at NENA standard valuation (i.e. unit value rates supplied by the ECB);
- the depreciation of NENA network assets must be as per the NENA valuation report;
- the closing value of NENA network assets must be as per the NENA valuation report;
- customer- and/or grant-funded asset values must be shown in the appropriate rows (in the absence of detailed records of such assets the licensee and the ECB will agree on a suitable percentage to be applied for such assets); and
- no return on assets is allowed for grant- and customer-funded assets.

The following stipulations apply regarding the **depreciation of assets**:

- values of property, investment property, plant and equipment must be stated at cost less accumulated depreciation;
- depreciation must be calculated at cost less residual value, using the straight-line method over the estimated useful life of the asset.
- The following estimated asset lives are provided as a guide:
 - Networks up to 33kV – refer to NENA
 - Networks over 33kV – as per professional asset valuation

- Investment property – 50 years
- Buildings – 50 years
- IT hardware – 5 years
- IT software – 2 years
- Vehicles (busses) – 10 years
- Vehicles (trucks) – 5 years
- Motor vehicles – 5 years
- Office equipment – 5 years
- Furniture and fittings – 5 years

The following stipulations apply regarding **investment property**:

- investment property is property in the form of land and buildings that is held to generate revenue (rentals and/or capital appreciation);
- investment property is not used in the production or supply of goods and services, nor for administrative purposes, nor for sale as part of ordinary business activities;
- investment property may not be included in the regulatory asset base, and must be ring-fenced in the licensee's accounts, as well as all costs and revenues associated with it; and
- only net profits derived from investment property must be recorded as "other revenue".

4.8.15 Schedule B2.2: Return

This sheet calculates the expected return on assets that is to form part of the licensee's revenue requirement, excluding the value of grant- or customer-funded assets. The return on net working capital (i.e. current assets minus current liabilities) is also calculated.

For licensees with a ring-fenced distribution undertaking within a larger organisation it is permissible to estimate the current assets and liabilities as follows (if no full ring-fencing information is available):

- Current assets = 2/12 projected revenue from post-paid sales; and
- Current liabilities = 1.5/12 * projected power purchase costs + 1/12 of O&M, Customer Service and Overheads Costs.

NOTE: The rate of return is specified by the ECB (in form of the WACC) and represents the regulated return that the licensee may generate from assets and net working capital employed, and the ECB will advise on the WACC to be used.

4.8.16 Schedule B 3.1: Bad Debt

This sheet calculates the regulated provision for bad debt, based on the revenue that the licensee wrote off in the previous year.

The ECB encourages licensees to improve their debt collection efforts and only allows a maximum of 1.25% of the revenue requirement to be included as provision for bad debt in the licensee's revenue requirement for the next year. Licensees are encouraged to improve on this maximum allowable figure.

4.8.17 Schedule C1.1: Revenue Requirement

The sheet "C1.1: RR" is the revenue requirement schedule and is the ORM-TD's main cost summary schedule. It relies on the accurate completion of the other schedules that are part of the ORM-TD workbook.

The schedule includes a summary of the electricity units sold, losses and purchases (in MWh), as well as purchased capacity (in kVA). It also summarises the main cost and other income components as are calculated in the ORM's other schedules based on the provisions contained in the National Distribution Tariff Study of 2018/19.

The total revenue requirement, once reviewed and approved by the ECB, forms the basis from which the licensee's indicative electricity tariffs are computed.

For transparency and control purposes this sheet includes a section below the revenue requirement calculation which summarises the regulatory interventions affecting the licensee's requested budget. These are items that the licensee is likely to face as actual expenditure, but which are not allowed as part of the revenue requirement and which are therefore not covered in the revenue from tariffs. The licensee will usually have to cover these items from provisions for return on assets and depreciation of assets (both of which are not intended to cover non-allowed operating costs). The ECB will monitor these amounts to assess the extent to which the licensee compromises its capability to invest in assets (represented by the depreciation and return allowances) by incurring unauthorised costs or carrying unapproved levels of inefficiency in power purchases or energy losses.

4.8.18 Schedule D1.1: Capital Budget

This sheet captures capital budget information, both for the current and the next financial year under consideration. Capital budget items must be divided into new as well as continuing projects. The sheet provides an indication of the current and next year's capital expenditure and serves as a useful indicator of possible changes that may affect future electricity tariffs.

4.8.19 Schedule EPM and EPM-P

The EPM and EPM-P sheets are **interface** sheets that allow the ECB to link the approved tariffs and projected sales volumes in the ORM to its regulatory database that is used, among others, to produce the schedule of approved tariffs. All tariffs and sales volumes contained in the standard, special and special services section of the Schedules A1.2, A1.2.1 and A1.2.2 are already linked to the EPM sheets and should not require user intervention.

Licensees with area differentiated tariffs who enter weighted average tariffs on the Schedule A1.2 through A1.2.2 may need to add the detailed tariffs manually to the EPM and EPM-P sheets. See also section 4.6.

4.8.20 Schedules C2.1 and C2.2 – TOU Definitions and TOU Sales Analysis

These schedules are used to record the TOU definition and analyse the TOU energy sales of the licensee.

5. Part C: ORM – Financial Reporting

5.1 Purpose

The purpose of the ORM – Financial Reporting (ORM-FR) is to

- a) capture a licensee's key financial and operating results at the end of a given financial year⁴;
- b) provide the ECB with an overview of a licensee's audited financial results using a standardised format (independent of the format of the annual financial statements used by a licensee), including details on focus areas of specific interest to the regulatory process such as borrowings, assets and debtors;
- c) provide the ECB with accurate information on actual expenditures, revenue and sales for a given reporting period as is used for statistical purposes as well as the ECB's annual revenue reconciliation process; and
- d) provide the ECB with performance management data and information aligned with the regulator's performance framework.

The ORM-FR is an Excel workbook that is provided by the ECB.

The submission of a completed ORM-FR for the previous financial year is a pre-requisite for the approval of tariffs for the next financial year.

Since a financial audit does not necessarily include a detailed audit of sales volumes, licensees are explicitly encouraged to have their sales volume information audited or otherwise verified by a competent external reviewer.

5.2 Introduction to the ORM-FR

The ORM-FR contains several schedules that capture the information contained in a licensee's balance sheet, income statement and cash flow statement of a given financial year. These schedules must agree with a licensee's audited annual financial statements.

If a licensee's audited results are not yet available when the submission of the ORM-FR is due, the licensee shall notify the ECB of the delay and its reasons. The ECB and licensee will then agree on the process to be followed, which may include postponing the due date for submission of the ORM-TD and ORM-FR or submitting an interim ORM-FR using information based on the latest management accounts instead of the audited results.

The ORM-FR also contains schedules that correspond to schedules that are part of the ORM-TD. These are intended to capture final (i.e. after-the-fact) data and information on a licensee's budget, power purchases, sales and revenues. While the information used in these schedules must correspond to the licensee's respective audited or verified numbers, the schedules may in- or exclude certain items that form part of the audited annual financial

⁴ Audited licensees are to use the audited annual financial statements to populate the ORM-FR workbook.

statements or vice versa. This implies that the totals may – in certain cases – not be directly comparable to the figures contained in the licensee's audited financial statements.

The ECB reserves the right to request a licensee's supporting documentation. These may, amongst others, include a licensee's management accounts and/or financial audit working papers to verify the information contained in the ORM-FR.

5.3 Populating the ORM-FR

5.3.1 Schedule F1.1 Balance Sheet

This schedule captures the information contained in the licensee's balance sheet for the reporting year under consideration, as per the licensee's audited annual financial statements.

Items included in the balance sheet of the audited statements but not listed in the ORM-FR are to be summated in the rows marked "Other ..." in each of the main sections of schedule F1.1.

Items where additional details are required must be captured in sub-schedules F1.1.1 to F1.1.9.

A licensee must ensure that the balance sheet balances, and that the totals included in the balance sheet agree with those contained in the respective audited financial statements.

5.3.2 Sub-Schedules F1.1.1 to F1.1.9

Schedules F1.1.1 to F1.1.9 are sub-schedules of a licensee's balance sheet schedule F1.1 and capture additional details of select items of relevance to the balance sheet.

The purpose of these sub-schedules is to provide the ECB with additional information of relevance to the items listed in the licensee's balance sheet, specifically focusing on aspects relating to a licensee's financial performance and status. Where applicable, items from the sub-schedules are transferred to the balance sheet.

Schedule F1.1.1 captures the values of a licensee's **fixed assets**, as per the audited results. Network asset figures used in this sub-schedule will likely be different from the NENA values used in schedule T3.2, while non-network asset figures should be the same as those in schedule T3.2.

Schedule F1.1.2 captures a licensee's **asset revaluation and depreciation** figures. Similar to schedule F1.1.1, network asset numbers will likely differ from those based on the NENA valuation used in schedule T3.2, while the remaining assets should be the same as used in schedule T3.2.

Schedule F1.1.3 captures a licensee's **short- and long-term investments**. Each major investment must be listed separately, while minor investments may be combined, where this is sensible.

Schedule F1.1.4 captures a licensee's **long-term debtors**. Each of the main long-term debtors must be listed separately, while minor debtors may be combined, where this is sensible.

Schedule F1.1.5 captures a licensee's **summary of customer debtors**, including the amounts of customer deposits held and an age analysis of customer debtors.

Schedule F1.1.6 captures the details of a licensee's **other (short-term) debtors**. Each of the main debtors must be listed separately, while minor debtors may be combined, where sensible.

Schedule F1.1.7 captures a licensee's **interest-bearing borrowings as at year-end**. Each main loan must be listed separately, and the purpose of each such loan must be stated. Minor loans may be combined per main usage category (e.g. for vehicles, for equipment, for other assets).

Schedule F1.1.8 captures a licensee's **trade and other payables**. Each main creditor must be listed separately, while minor creditors may be combined using the main usage categories.

Schedule F1.1.9 captures a licensee's **short-term borrowings**. Each main lender must be listed separately, while minor lenders may be combined, where sensible.

5.3.3 Schedule F1.2 Income Statement

This schedule captures a licensee's income statement for the reporting year, as per the respective audited annual financial statements.

Items included in the income statement of the audited financial statements but not listed in the ORM-FR must be summated in the rows marked "Other ..." in each of the main sections in schedule F1.2.

A licensee must ensure that the totals included in the income statement agree with those contained in the respective audited financial statements.

5.3.4 Schedule F1.3 Cash Flow Statement

This schedule captures a licensee's cash flow statement for the reporting year, as per the respective audited financial statements.

Items included in the cash flow statement of the audited financial statements but not listed in the ORM-FR must be summated in the rows marked "Other ..." in each of the main sections in schedule F1.3.

A licensee must ensure that the totals included in the cash flow statement agree with those contained in the respective audited financial statements.

5.4 ORM-FR Regulatory Reporting Schedules

The schedules named T*.* are identical in layout and purpose to their counterparts in the ORM-TD, except that they only include the audited/verified results for a given year.

The relevant sections of the ORM-TD user guide apply to the completion of these schedules too, except that the schedules T*.* are **strictly to be populated with only audited/verified**

- financial results (budget, asset values except those relating to NENA data);
- customer and sales data, incl. ECB-approved tariffs and verified final sales;
- power purchases corresponding to supplier invoices; and
- local authority surcharges that have been paid.

5.5 ORM-FR Performance Management Schedules

The ORM-FR includes two schedules related to a licensee's individual performance and align and are used as part of the ECB's Performance Management Framework (as updated).

5.5.1 Schedule P1.1 Performance Data Matrix

The performance data matrix was developed as part of the ECB's Performance Management Framework, capturing data to determine various performance indicators. The matrix includes

information on the expected source of each data item as well as the purpose for which the item is required.

Most of the inputs required in this schedule are linked to other schedules in the ORM-FR, but some items must be entered manually, including the following:

- Allocated management and support services costs (for ring-fenced licensees only) – this is the sum of other departments' costs recovered from electricity;
- Total post-paid sales (to calculate debtor days);
- Wheeling costs (if applicable);
- Loan principal and lease principal payments;
- Marketable securities (if any);
- A licensee's employee numbers;
- Network data (from NENA for medium voltage and low voltage networks)
- A licensee's geographical and population-relevant areal data; and
- Data related to the quality of service and supply (to be drawn from QOSSS reporting).

5.5.2 Schedule P1.2 Performance Indicators

This schedule calculates some performance indicators as per the ECB's Performance Management Framework ⁵.

The inputs required in this sheet are for ECB-approved data only and are normally entered by ECB staff once a licensee has submitted a completed ORM-FR to the regulator.

⁵ For more information on the indicators please refer to the ECB's Performance Management Framework.

6. Part D: Tariff Determination and Financial Reporting Process

6.1 Tariff Determination and Financial Reporting Cycle

The tariff determination and financial reporting process for licensees is an annual process with a defined succession of events as broadly illustrated in the figure below:

Figure 5: Tariff Application Cycle

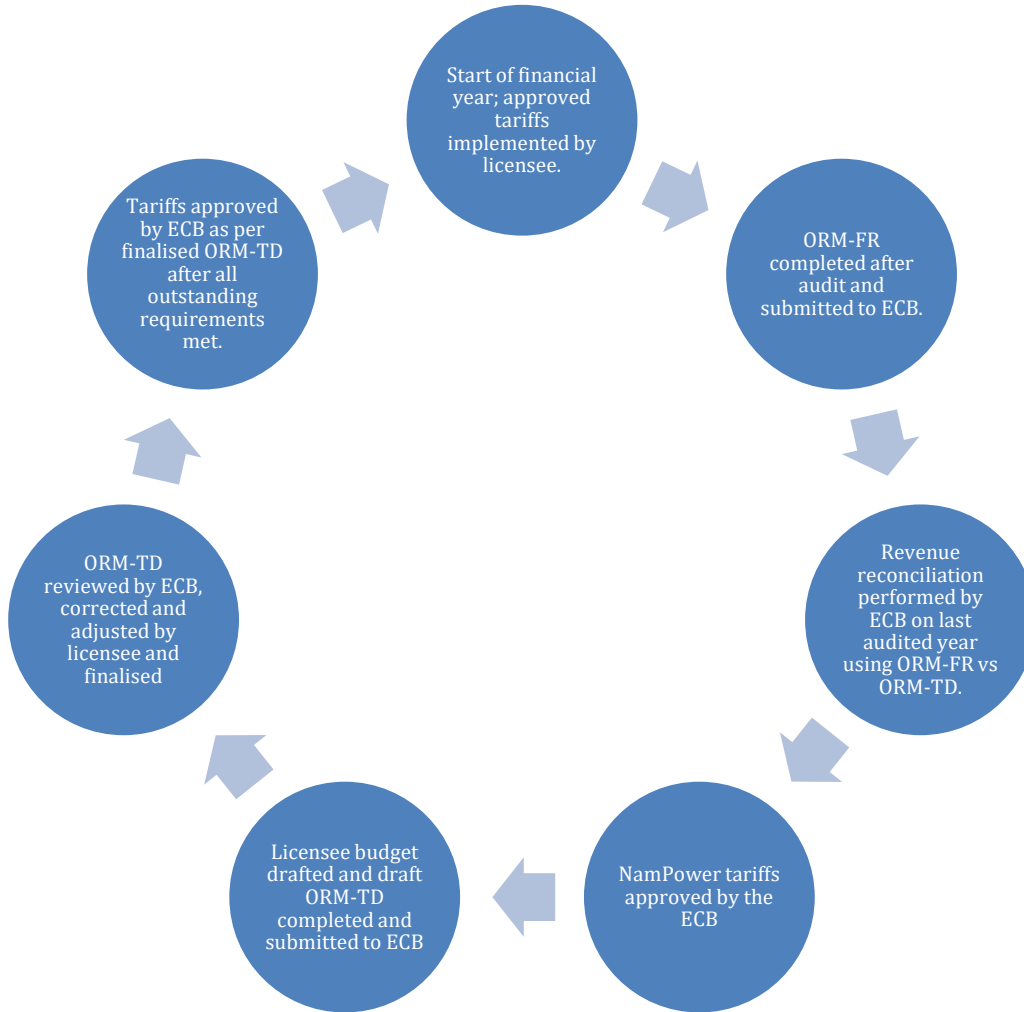


Table 5 expands on the above cycle and sets indicative target dates.

Table 5: Reporting Cycle Activities and their Timing

Event	Timing	Remarks
Start of licensee financial year N	1 July	Expected implementation date for new approved tariffs. Customers are duly notified of new tariffs.

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Event	Timing	Remarks
Licensee completes financial results for past year N-1, audit completed	31 December (as per license conditions)	<p>Audited financial statements to be submitted to the ECB when available.</p> <p>If the audit is delayed the licensee notifies the ECB of the expected delay as well as the reasons for the delay.</p> <p>The ECB agrees with the licensee regarding submission of an interim or delayed ORM-FR.</p>
Licensee completes ORM-FR with audited results for prior year N-1	31 January	ORM-FR to be completed and submitted with final information for year N-1
Revenue reconciliation	28 February	<p>The ECB performs a revenue reconciliation for year N-1 by comparing the ORM-FR to the ORM-TD submitted earlier for the year N-1. This may result in reconciliation amounts being determined for the next ORM-TD.</p> <p>The ECB reviews all relevant ECB audit results and associated requirements, including remedial actions and document submissions, and alerts the licensee to any outstanding requirements.</p>
NamPower tariff approval process	31 March	The ECB reviews and approves NamPower's tariff application for year N+1. NamPower's approved tariff for year N+1 are published.
Licensee budget and tariff application process	30 April	<p>The licensee prepares a draft operating budget as well as sales and purchases forecasts, populates the ORM-TD for year N+1, designs proposed tariffs for year N+1 and submits the draft ORM to the ECB for scrutiny.</p> <p>The licensee reviews any requirements for submission of documents and/or ECB audit issues that must be addressed, ensuring that all requirements are met before submission of the ORM-TD to the ECB.</p>
Tariff application review	30 May	<p>The ECB reviews the draft ORM submitted by the licensee and resolves any questions or discussions with the licensee.</p> <p>The licensee submits a final revised ORM-TD tariff application with a formal request letter and required supporting information.</p> <p>The ECB considers and approves the licensee's tariffs and returns the approved ORM-TD to the licensee for records.</p>
Tariff implementation	1 July	<p>The licensee informs customers of the approved changes to tariffs and other conditions of supply.</p> <p>The new approved tariffs are implemented as from the approved effective date.</p>

6.2 Additional Matters Regarding the Tariff Application Cycle

6.2.1 Documents and Remedial Actions Required of Licensee

As part of the tariff review process as well as ECB's compliance audits the ECB may require the licensee to submit certain documents and/or implement certain remedial actions to address non-compliance issues and/or provide documentary evidence for certain matters to the ECB. Such requirements will be submitted by the ECB to the licensee in writing. The licensee is responsible for acknowledging such requirements and complying with such requirements within a reasonable time.

As part of its enforcement mechanisms the ECB may decline to process or approve tariff reviews if a licensee fails to react within a reasonable time to compliance requirements and supply adequate evidence of compliance to the ECB in good time before the tariff submission is made.

In case of any uncertainties or where licensees face issues in complying to ECB regulatory requirements the licensee should contact the ECB immediately and make arrangements for permission to comply / submit evidence or documents at a later date agreed between the licensee and the ECB as being reasonable. In the absence of such arrangements the ECB will regard the licensee as being non-compliant if any compliance requirements have not been met and reported on by the time that the next tariff submission is received by the ECB.

6.2.2 Completion of the ORM-TD and ORM-FR

Licensees are encouraged to contact the ECB with any queries that may arise during the completion of the ORM documents to ensure that any issues are addressed in good time.

In cases where the approval of NamPower's tariffs may be delayed, licensees are encouraged to complete the ORM-TD with all data except final NamPower tariffs and submit this to the ECB for a preliminary review. Such a preliminary review can be used to reach agreement of budget levels, allowable expenses and proposed draft tariffs. This will substantially reduce the time required for the final ORM-TD review once the NamPower tariffs have been approved.

Should a licensee's audit be delayed beyond the 6-month period after year-end the licensee should notify the ECB of the reasons for and likely duration of such delay before the expiry of the six-month period. The licensee and the ECB may then jointly decide whether an interim ORM-FR should be submitted on the basis of the licensee's management accounts (unaudited) or whether the submission of the ORM-FR and the revenue reconciliation process should be delayed.

A licensee's failure to submit a completed ORM-FR or make arrangements with the ECB regarding its late submission may lead to the regulator declining to process the licensee's ORM-TD.