Regulatory Reset
for the July 2011 to June 2015
Third Regulatory Period for
the First Entry Group of
Privately Owned Distribution Utilities
subject to
Performance Based Regulation

<u>Position Paper</u>

December 1, 2009

Republic of the Philippines

Energy Regulatory Commission

San Miguel Avenue, Pasig City

Regulatory Reset for the July 2011 to June 2015 Third Regulatory Period for the First Entry Group of Privately Owned Distribution Utilities subject to Performance Based Regulation

Position Paper

Pursuant to Section 43(f) of Republic Act No. 9136, otherwise known as the Electric Power Industry Reform Act of 2001, and Rule 15, Section 5(a) of the Implementing Rules and Regulations issued pursuant to that Act, the Energy Regulatory Commission (ERC) promulgated the Guidelines on the Methodology for Setting Distribution Wheeling Rates, referred to as the 'DWRG', (ERC Resolution no 12-02, Series of 2004, dated December 20, 2004). The DWRG has subsequently been revised and re-issued as the Rules for Setting Distribution Wheeling Rates for Privately-Owned Distribution Utilities Entering Performance Based Regulation [Second and Later Entry Points] [ERC Resolution No. 54, Series of 2006, dated December 13, 2006, hereafter referred to as the 'RDWR'].

Following consultation from September to December 2008 on changes to the rules, an updated version of the RDWR was published, to form the basis for future Regulatory Resets. The RDWR for the Third Entry Point for Privately-Owned Distribution Utilities Entering Performance Based Regulation, was published on December 5, 2008. Likewise, an updated version of the RDWR, was published on June 22, 2009, pertaining specifically to the Fourth Entry Point for Privately-Owned Distribution Utilities.

Under clause 7.1.2 of the RDWR, the ERC must publish a Regulatory Reset Issues Paper to provide the ERC's initial views on the issues to be discussed during the pending Regulatory Reset Process, and to specify the information required to be delivered by each Regulated Entity for the purposes of the Regulatory Reset Process and the time by which such information should be delivered. The Issues Paper for the Regulated Entities entering Performance Based Regulation (PBR) at the First Entry Point for the Third Regulatory Period, on July 1, 2011 was published on October 5, 2009 and submissions were invited on the Paper. Public Consultation on these submissions took place on November 17, 2009

This Position Paper describes the final position of the ERC with regard to the price reset for the Third Regulatory Period for the First Entry Group into PBR, following the ERC's consideration of the submissions received on the Issues Paper and views and observations raised during the consultation process.

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1. INTRODUCTION

1.1 Purpose

In January 2005, the Energy Regulatory Commission (ERC) adopted the Distribution Wheeling Rate Guidelines (DWRG) which had been developed through a public consultation process in 2004. The DWRG dated December 10, 2004 outlined a Performance Based Regulation (PBR) framework using a price cap on the provision of wheeling services by private Distribution Utilities. This DWRG described the setting of rates under PBR, which the ERC has adopted as an alternative form of internationally-accepted rate-setting methodology under Section 43(f) of Republic Act No. 9136, otherwise known as the Electric Power Industry Reform Act of 2001 (EPIRA), and Rule 15, Section 5(a) of its Implementing Rules and Regulations (IRR).

Annex B of ERC Resolution No. 12-02 Series of 2004 "Adopting a Methodology for Setting Distribution Wheeling Rates", dated December 10, 2004, defined five entry points into PBR for privately owned Distribution Utilities. This was later amended to four entry points by the ERC under Resolution No. 24, series of 2007, dated October 24, 2007.

This Position Paper relates specifically to the First Entry Group - those Regulated Entities that will enter the Third Regulatory Period of PBR at the First Entry Point, commencing on July 1, 2011. The privately owned Distribution Utilities entering PBR at the various entry points are listed in Appendix K.

During the Regulatory Reset Process for the First Entry Group for the Second Regulatory Period, certain revisions were made to the DWRG. Following consultation, a new set of regulatory rules for PBR for Distribution Utilities was issued, the Rules for Setting Distribution Wheeling Rates for Privately-Owned Distribution Utilities Entering Performance Based Regulation [First Entry Point], dated July 26, 2006 (the RDWR). Subsequently, following further consultation and to accommodate the further entry groups, further updated versions of the RDWR was published, with the latest being the RDWR for the Fourth Entry Group, dated June 22, 2009.

For the Third Regulatory Period, further revisions to the RDWR were required to reflect the changes between this period and the Second Regulatory Period. Following public consultation, an updated version of the Rules for Setting Distribution Wheeling Rates for Privately-Owned Distribution Utilities operating under Performance Based Regulation (First Entry Group, Third Regulatory Period) has therefore been issued on December 1, 2009.

The RDWR specifies that the ERC must publish an Issues Paper to commence the regulatory reset process, not later than 21 months prior to the start of each Regulatory Period. The Issues Paper for the Regulated Entities entering Performance Based Regulation (PBR) at the First Entry Point for the Third Regulatory Period, on July 1, 2011 was published on October 5, 2009 and submissions were invited on the Paper. Public Consultation on these submissions took place on November 17, 2009. Following the submissions and consultation, this Position Paper:

- provides the ERC's views and intentions with regard to the issues raised by the pending Regulatory Reset Process for the First Entry Group for the Third Regulatory Period;
- specifies the information to be provided by each Regulated Entity for the purposes of the Regulatory Reset Process and the time by which it has to be provided; and
- provides the time by which each Regulatory Entity must file an application with the ERC to commence the Regulatory Reset Process.

The Position Paper also provides additional guidance to the independent expert(s) who may be appointed to assist and advise the ERC during the Regulatory Reset Process.

1.2 Use of terms and definitions in the Position Paper

Throughout this Position Paper, where capitalized terms are used, this indicates that the term has been defined in Clause 1.3 of the RDWR or Clause 1.2 of the ERC's Distribution Services and Open Access Rules (DSOAR). Where there is any contradiction in the definition of the terms between the RDWR and the DSOAR, the later definition, as contained in the DSOAR, should apply.

A number of additional terms have also been defined for the purposes of this Position Paper. These terms have the following meanings:

First Entry Group	The group of Regulated Entities who will enter the Third Regulatory Period under PBR at the July 2011 Entry Point.
First Entry Point	July 1, 2011 - the date at which the First group of privately owned Distribution Companies, thus mandated by the ERC in terms of Resolution No. 12-02 Series of 2004, amended in terms of Resolution No. 27 Series of 2007, will enter the Third Regulatory Period under PBR.
Revenue Application	A formal application that has to be made by each Regulated Entity to the ERC, in which approval is sought for the efficient revenue requirement for that Regulated Entity for the Third Regulatory Period. This will form the basis of the information considered by the ERC for its draft and final determinations on the price-control arrangements for distribution wheeling rates for the Third Regulatory Period.

1.2.1 Reading the Position Paper in conjunction with the draft RDWR

This Issues Paper is intended to be read in conjunction with the RDWR prepared for the First Entry Group, which is a public document and available on the ERC website.[1] A key goal of the Position Paper is to inform interested parties about the ERC's interpretation of various aspects contained in the draft RDWR, to provide a better level of general understanding of PBR and to assist in the rate-setting process. Where deemed necessary,

[1] http://www.erc.gov.ph

some sections in the RDWR are therefore further explained and clarified in this Position Paper.

Where any contradictions exist between the Position Paper and the RDWR, the RDWR should take precedence.

To avoid the potential for confusion between instances where references are made to provisions in the RDWR or the Position Paper, all references to provisions from the RDWR will refer to clauses or articles. References to provisions in the Position Paper will refer to Sections.

1.3 Services covered under the RDWR

The purpose of the RDWR is to specifically describe the methodology for setting distribution wheeling rates, for the provision of Regulated Distribution Services. It should be read in conjunction with the ERC's DSOAR, which describes the rules for access to Distribution Systems and the ERC's Business Separation Guidelines (BSG), which describe the framework and rules for the structural and functional unbundling of the business activities of Electric Power Industry Participants.

The BSG (par. 4.4) describes the services in Table 1.1 as distribution and related activities.

Table 1.1: Distribution and related activities as defined in the BSG

Service	Description in BSG
Distribution services	• Provision of regulated distribution services. • Provision of Ancillary Services that are provided using assets which form part of a Distribution System. • Planning, maintenance, augmentation and operation of a Distribution System. • Provision, installation, commissioning, testing, repair, maintenance and reading of WESM-related meters that are not also used to measure the delivery of electricity to End-users or other customers. • Billing, collection and customer service for customers purchasing distribution and distribution connection services (whether such services are provided to those customers, to Suppliers or to any other person).
Distribution connection services	• Provision of access services (i.e. connection services). • Planning, installation, maintenance, augmentation, testing and operation of Distribution Connection Assets. • Services that support the above-mentioned services.
Regulated retail services	• Billing, collection, customer service, energy trading and electricity sales for Captive Market. • Provision, installation, commissioning, testing, repair, maintenance and reading of meters that are used to measure the delivery of electricity to customers in the Captive Market.
Non-regulated retail services	• Billing, collection, customer service, energy trading and electricity sales for Contestable Market or for other customers who purchase electricity but are not End-users. • Provision, installation, commissioning, testing, repair, maintenance and reading of meters that are used to measure the delivery of electricity to customers in the Contestable Market or to customers who are not End-users (whether such services are provided to those customers, to Suppliers or to any

	other person).
Related businesses	• Related businesses utilizing distribution assets/facilities/staff (e.g. telecommunications business utilizing distribution wires and/or poles).
Wholesale aggregation services	• Billing, collection and the provision of customer services to Distribution Utilities; • Energy trading (including the purchase of electricity and hedging activities) undertaken in connection with the sale of electricity to Distribution Utilities; • The sale of electricity to Distribution Utilities.
Last resort supply services	• Billing, collection, basic customer service, energy trading and electricity sales for Supplier of Last Resort customer.

Of these services, the following are included under the distribution wheeling rates:

- Distribution services[2]
- Distribution Connection Services
- Regulated retail services

It should, however, be noted that in terms of the DSOAR, once fully implemented, Distribution Connection Services would be deemed an Excluded Service and costs associated with this service would be recovered separately from distribution wheeling charges (under distribution connection charges). At that stage, Distribution Connection Services (or the part thereof that is determined by the ERC to be Excluded Services), would no longer be taken into account when determining distribution wheeling rates.

1.4 First Regulatory Period

For the first entry group, Regulated Entities were given the option to enter PBR at the First Regulatory Period or the Second Regulatory Period. For the Second, and subsequent entry groups, there was no First Regulatory Period and they therefore entered PBR directly in the Second Regulatory Period.

1.5 Outline of this paper

This Position Paper is structured as follows:

- Section 2 provides a high-level, descriptive overview of the PBR and the price-setting mechanism as described in the RDWR.
- Section 3 provides the process and time-line for the reset process, highlighting the dates at which submissions or information is required from Regulated Entities. It also discusses the proposed use of expert(s) by the ERC for the Reset Process.
- Sections 4 to 13 discuss various aspects of the PBR and the ERC's views and intended approach thereon.

[2] Note that while the definition of distribution services in terms of the BSG is not identical to that of the term "Regulated Distribution Services" as described in the RDWR, these are intended to address the same service. For the purpose of this Issues Paper, the "distribution services" described in the BSG should therefore be read as the "Regulated Distribution Services" in the RDWR.

- The appendices provide supporting information and more expanded definitions of aspects raised in the body of the paper. Data templates are also provided for the information that has to be provided by Regulated Entities to the ERC as part of the Regulatory Reset Process.

2. OVERVIEW OF PRICE SETTING METHODOLOGY

This section presents a brief, high-level overview of the price setting methodology as described in the RDWR.

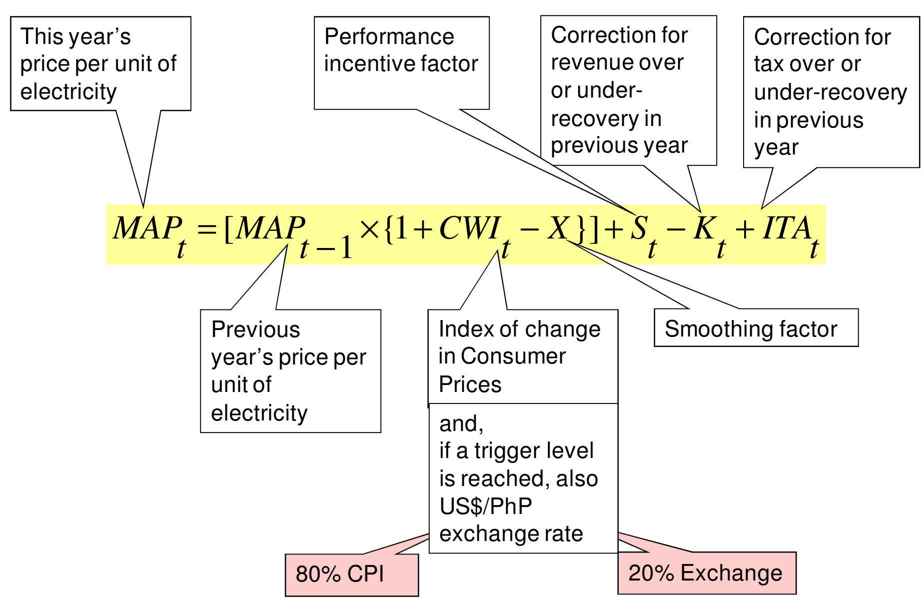
The RDWR applies only to privately owned Distribution Utilities that have commenced the Regulatory Reset Process and are therefore defined as Regulated Entities in terms of the RDWR. It determines the manner in which the maximum electricity distribution wheeling rates for providing Regulated Distribution Services may be charged by Regulated Entities and the Performance Incentive Scheme to be implemented under PBR.[3]

2.1 Price cap

The RDWR describes a form of Performance Based Regulation (PBR) for Regulated Distribution Services. Fundamentally, it sets a cap on the maximum average rates for providing distribution wheeling services. This price cap is set for each Regulated Entity to allow them to recover efficient expenditure only and provide an appropriate return to investors in the Regulated Distribution Systems. In addition, built-in incentives exist to further improve the efficiency of operating and capital expenditures, as well as network and service performance levels.

Regulation occurs in four-year periods and the annual average price-caps are set in accordance with the actual Philippines consumer price index (CPI) and Philippine Peso/US dollar exchange rate experienced over the Regulatory Period, modified by a smoothing factor (X-factor) that is determined in terms of the RDWR. This is a variant of the "CPI-X" form of regulation. The price cap formula is demonstrated in Figure 2.1 below, giving a high level explanation of each of the terms used.

Figure 2.1: Simple presentation of the maximum price-cap formula



$$MAP_t = [MAP_{t-1} \times \{1 + CWI_t - X\}] + S_t - K_t + ITA_t$$

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[3] Distribution wheeling charges are distinct from other energy charges such as transmission wheeling charges or energy purchase costs. It only pertains to those regulated services described in Section 1.3.

It will be noted that the formula refers to a weighted index rather than CPI adjustments. Normally this weighted index would include the Philippines CPI only. However, if the PhP/US$ exchange rate fluctuates by more than a predefined trigger level, the exchange rate is also incorporated into the weighted index.[4]

A key component in the price cap is the X-factor. This is a smoothing factor that prevents undue price fluctuations, after allowing for the approved, efficient expenditure of a Regulated Entity. It is individually determined for each entity. Under the base assumption that the efficiency of Regulated Entities can be improved over time, in the majority of cases the X-factor will be positive.[5] This will, over time, result in the price of electricity increasing at a rate lower than inflation, or in other words a decline in the real electricity price.[6] Calculation of the X-factor is further discussed in Section 2.3 below.

It is widely recognized that there is a trade-off between the quality and pricing of distribution services. In a regulatory environment where prices or revenue is capped (such as under PBR), and there is an incentive for Regulated Entities to increase profits by limiting expenditure, it is therefore necessary that the regulator also ensures that no material deterioration in service quality levels are experienced. For the form of PBR adopted in the Philippines this is achieved through a quality-based incentive factor, the S-factor. This factor takes into account the reliability of a distribution network and the quality of service delivery. If the weighted service performance targets for a Regulated Entity are exceeded, it will result in a reward (an addition to the price cap). Alternatively, if the targets are not met, it will result in a penalty (a reduction of the price cap). This incentive component is further discussed in Section 10.3.

The other factors in the formula are to make corrections to over- or under-recovery of revenue and/or taxes during previous Regulatory Years.

Implicit to the setting of a price cap, is the fact that Regulated Entities have an incentive to improve their efficiency. Because the calculation of the X-factor depends on the approved revenue allowance for a Regulated Entity (see Section 2.2) and it is fixed for the duration of a Regulatory Period, reductions in expenditure result in direct profit gains[7]. Over time, these efficiency gains are shared by customers since they are reflected in lower price settings, through a higher X-factor for later Regulatory Periods, recognizing the earlier efficiency gains. To avoid minimizing the incentive to reduce costs towards the end of a Regulatory Period, it is intended to carry over any efficiency gains for a full four-year period. (The efficiency carry-over mechanism is discussed in Section 8.)

[4] This is to reflect the fact that a large part of major capital equipment used by Philippine electricity distributors are imported, using the US$ as the proxy currency.

[5] This will not always be the case, especially earlier on after adopting PBR when addressing historical imbalances or under-recoveries may result in real price increases during the initial regulatory period.

[6] The word “real” is used in this document in its financial context. It implies that a figure is given in current value terms, i.e. ignoring the impact of inflation.

[7] Increases in expenditure will erode profits.

2.2 Revenue requirements

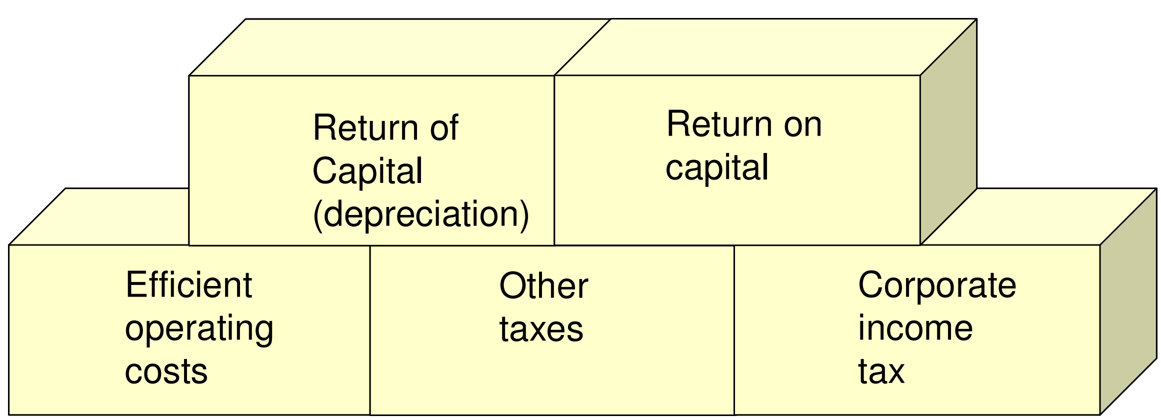
Underlying the determination of the X-factor, is the calculation of the annual efficient revenue to which a Regulated Entity should be entitled. During the regulatory reset process, in their Revenue Applications, Regulated Entities have to provide the ERC with estimates of their forecast revenue requirements for the Third Regulatory Period. The ERC will approve this after consultation and making such changes as are warranted.

It is essential that the price setting mechanism adequately provides for a Regulated Entity's efficient revenue requirements, to sustain efficient service levels and sufficient infrastructure investment. Over time this will ensure a sustainable supply, with sufficient capacity and appropriate quality levels. Such sustainability is essential to encourage growth and establishment of new businesses in a region, resulting in a positive impact on the whole of the regional economy. Conversely, under-investment in Distribution Systems due to insufficient incentives to invest, may in the short-term lead to price reductions, but will in the longer term lead to unreliable or under-capacity electricity supplies, with potentially severe negative economic and societal implications for a supply area.

At the same time, it is the duty of a regulator to ensure that the interests of customers are protected, being a captive market of electricity Distribution Utilities working as a monopoly. It has to ensure that allowed expenditure is efficient and targeted at achieving maximum benefits to consumers, at the lowest sustainable prices that would ensure the continued effective operation of Distribution Systems.

The calculation of the fair revenue requirement of Regulated Entities is based on the so-called building block approach, as illustrated in Figure 2.2 below. This highlights those cost components which build up the total efficient revenue requirement for Regulated Entities.

Figure 2.2: Building blocks for calculating revenue requirements



Each of these components is briefly discussed below.

2.2.1 *Operating & maintenance costs*

The operating and maintenance cost component allows Regulated Entities the ability to recover efficient expenditure incurred in operating a Distribution System to provide acceptable service levels to all customers, and to maintain the Distribution System to a standard that will ensure assets can deliver at full rated capacity for their full standard lives.

2.2.2 *Regulatory depreciation*

The regulatory depreciation component is to allow Regulated Entities a return of the capital invested in a Regulated Distribution System, over standard asset lives.

2.2.3 *Return on capital*

The return on capital component is to allow investors in Regulated Distribution Systems a reasonable return on their investments, commensurate with the riskiness of the investment. The return on capital is calculated as the product of the value of the Regulatory Asset Base and the regulatory weighted average cost of capital (Regulatory WACC).[8]

The value of the Rolled-Forward Depreciated Asset Base is used to calculate the return on capital. The opening value of the asset base is determined at the start of each Regulatory Period and shall then be rolled forward each year by adding the approved efficient capital expenditure and deducting the depreciation of the asset base and any disposals made.

The opening value of the Regulatory Asset Base is calculated using the optimized depreciated replacement cost (ODRC) methodology. This methodology values assets at the historical or modern equivalent cost to replace them, notionally removing any unnecessary assets from the asset base[9], and depreciating the residual asset base in accordance with the actual asset ages.

2.2.4 *Corporate income tax*

The RDWR allows for the recovery of corporate income tax as an expense that a Regulated Entity has to incur in the normal course of its business. The tax payable is based on the regulated profit realized in the Regulated Distribution System each year, applying the corporate income tax rate for a particular Regulated Entity to that amount.

The fact that corporate income tax is an allowed recoverable expense, is reflected in the use of an after-tax Regulatory WACC to determine the reasonable return on investments.[10]

However, following recent consultation on the changes to the RDWR and consideration of price-setting decisions to date, the ERC was unanimously requested by the Regulated Entities that the corporate income tax component should be set to zero for the Second Regulatory Period. The ERC has decided to accept this recommendation, which will also apply to the Third Regulatory Period. Since this building block is included in PBR based

[8] Allowance is also made for a return on the working capital required by Regulated Entities.

[9] Unnecessary assets are those that are stranded, redundant, provide unnecessarily high service standards or have capacity in excess of what is required for a realistic planning window.

[10] If corporate income tax was not considered a recoverable cost, an equivalent revenue outcome would be achieved by allowing a corresponding pre-tax Regulatory WACC to be earned on the asset base,

on sound economic principles, it will however not be removed and the position will be reconsidered at future Regulatory Periods.

2.2.5 Other taxes, levies and duties

The last building block component is an allowance to Regulated Entities to recover costs incurred for levies, duties or other taxes (excluding corporate income tax) in the operation and management of the Regulated Distribution Systems.

2.3 Smoothing factors

The final step to allow the maximum annual price cap to be set after the allowed annual revenue for a Regulated Entity has been determined, is the calculation of the X-factor. The calculation, in essence, determines the rate at which the price-cap would have to change over a Regulatory Period to ensure the allowed revenue for a Regulated Entity will be recovered over the four years of the Regulatory Period. This rate of change is a combination of the expected inflation and the X-factor – with the X-factor therefore indicating the real decline or growth in electricity prices.

In addition the X-factor formula also contains a further smoothing factor – the P_0-factor. This factor is set by the ERC to avoid price shocks during the transition from one regulatory period to the next, and also to take into account windfall losses or gains that may arise as a result of external factors. By selecting a higher P_0-factor, the price-cap during the first Regulatory Year will be reduced, but the X-factor will be lower and the resulting price increases will be higher over the Regulatory Period. The opposite is true for a lower P_0-factor.

3. PROCESS AND TIMETABLE

The ERC is committed to conduct public consultation on the next steps in the implementation of the PBR framework for private Distribution Utilities, including the Regulatory Reset Process.

The RDWR specifies this Regulatory Reset Process over a period of approximately 21 months from September 2009 to the start of the Third Regulatory Period on July 1, 2011. This process and its associated timetable are discussed below.

3.1 Reset process

The reset process and timeline are shown in the flowchart in Figure 3.1. In broad terms, the process that will be followed is as follows:

- An Issues Paper was published by the ERC, accompanied by a draft RDWR. Public submissions on these two documents were invited.
- Following the submissions on the Issues Paper and draft RDWR, public consultation sessions to discuss these were held at the ERC offices in Manila on November 16-17, 2009 for the RDWR and Issues Paper respectively.
- Following the consultation, this Position Paper and a final version of the RDWR is published, in which the ERC's final decisions on the rules for the Third Regulatory Period and the reset process are given.
- Regulated Entities will collect historical network and service performance data and submit this to the ERC.
- The ERC will develop an ODRC Valuation Handbook which will set out the methodology that Regulated Entities are to adopt to value their Regulatory Asset Base for the purposes of their Revenue Applications. The Handbook will be subject to full public consultation, after which it will be issued.
- The ERC will finalize the performance incentive scheme, determine the Regulatory WACC and carry out all of its other obligations in terms of the RDWR, with the assistance of a Regulatory Reset Expert(s) as appropriate. This information will be provided to the Regulated Entities to allow them to file their rate applications.
- Regulated Entities will collect the necessary expenditure data, prepare their asset valuations (based on the methodology provided in the Handbook) and expenditure forecasts, and submit their Revenue Application to the ERC for approval of their revenue requirements.
- In the same Revenue Application, the Regulated Entities will also submit their proposed performance incentive schemes for the Third Regulatory Period for ERC approval.
- Each Regulated Entity will make a public presentation explaining their Revenue Applications.
- Public hearings will be conducted on the Revenue Applications, allowing for queries and clarifications by parties of record to the revenue filings.

- Clarification meetings will be held between the ERC, its Reset Experts and technical staff of the Regulated Entities, to discuss aspects of the Revenue Applications in detail. These meetings may be observed by all parties of record.
- The ERC will review the Revenue Applications submitted by the Regulated Entities and based on this review and the outcome of the public consultation, publish a draft price determination, indicating its preliminary decision on the price-control arrangements for Regulated Distribution Services that will apply to each Regulated Entity for the Regulatory Period.
- Submissions will be invited and public consultation sessions conducted on the draft determination, in each of the three areas where the Regulated Utilities in the First Entry Group principally operates.
- After considering new evidence presented during the consultation process, the ERC will prepare a final determination on the price-control arrangements for providing distribution wheeling rates for the Third Regulatory Period, setting out the final decisions on the price-cap, X-factor and performance incentive scheme for each Regulated Distribution System.
- The Regulated Entities are required to convert the initial price-caps into distribution rates and submit a rate-filing. This filing will be subject to public hearings. After the ERC has approved the rate-filing, making amendments as appropriate, these rates will be implemented from the start of the Third Regulatory Period.

3.2 Reset timetable

Article VII of the RDWR sets out the time frames within which various activities are required to be performed during the Regulatory Reset Process. Taking this into account, the key dates will be as set out in Table 3.1 and Figure 3.1.

Table 3.1: Timeline for the Regulatory Reset Process

Position Paper		
i.	Issues Paper submitted for consultation	Oct. 6, 2009
ii.	Public consultation to present the Issues Paper	Oct 13, 2009
iii.	Submission of comments on Issues Paper close	Nov 6, 2009
iv.	Consultation on submissions made on the Issues Paper	Nov 16, 2009
v.	Position Paper Posted at the ERC website	Dec 14, 2009
Valuation Handbook		
i.	ERC to appoint Reset Expert to prepare a general ODRC Valuation Handbook to be used for asset valuations for the Third Regulatory Period	Dec 2009
ii.	Draft Valuation Handbook published for consultation	Mar 31, 2010
iii.	Submissions on Valuation Handbook close	Apr 21, 2010
iv.	Public consultation on Valuation Handbook	May 2010
v.	Final Valuation Handbook issued to Regulated Entities	May 21, 2010
Information gathering and analysis: Revenue Application		
i.	Pre-filing conference	Mar 15, 2010
ii.	ERC to communicate other regulatory parameters (including the Regulatory WACC, working capital computation and final performance incentive scheme) to Regulated	May 7, 2010

	Entities	
iii.	ERC to finalize review team for Distribution Utility Revenue Applications	June 4, 2010
iv.	Utilities to file Revenue Applications (including performance incentive scheme details)	June 15, 2010
v.	ERC to conduct jurisdictional & expository hearings on Revenue Applications	July 2010
vi.	ERC to conduct clarificatory meetings and evidentiary hearings on Revenue Applications	Aug/Oct 2010
Draft determination process		
i.	Draft determination published for consultation	Nov 11, 2010
ii.	Submissions on draft determination close	Dec 8, 2010
iii.	Public consultation on draft determination	Jan 2011
Final determination published		Feb 23, 2011
Rate filing		
i.	Distribution Utilities' rate filing	Mar 23, 2011
ii.	Public hearings on rate filings	Apr 2011
ii.	Rate filings approved	June 1, 2011
Start of Third Regulatory Period		July 1, 2011

The RDWR involves only the determination of a maximum annual price for distribution wheeling services and excludes prescriptions on how this should be translated into a tariff structure. The design of tariff structures is addressed under Article V of the DSOAR and the Uniform Filing Requirements (UFR) issued by the ERC on October 31, 2001.

3.2.1 Pre-filing conference

At a date not later than three months before Regulated Entities are required to submit their Revenue Applications, the ERC will arrange for a pre-filing conference to be held at its offices in Manila. Representatives from the Regulated Entities in the First Entry Group will be invited to attend this conference. At the conference, the following will be discussed with and provided to Regulated Entities:

a) The pro-forma format for the Revenue Application and associated performance incentive scheme application.

b) Spreadsheet models in which a Regulated Entity's historical and forecast operating and maintenance expenditure data has to be submitted. These models will make provision for forecasts of local and international expenditure, as well as the conversion of real values to nominal values (or vice versa where applicable).

c) Spreadsheet models in which a Regulated Entity's historical and forecast taxes (other than corporate income tax), levies and duties expenditure data has to be submitted. These models will make provision for forecasts of local and international expenditure, as well as the conversion of real values to nominal values (or vice versa where applicable).

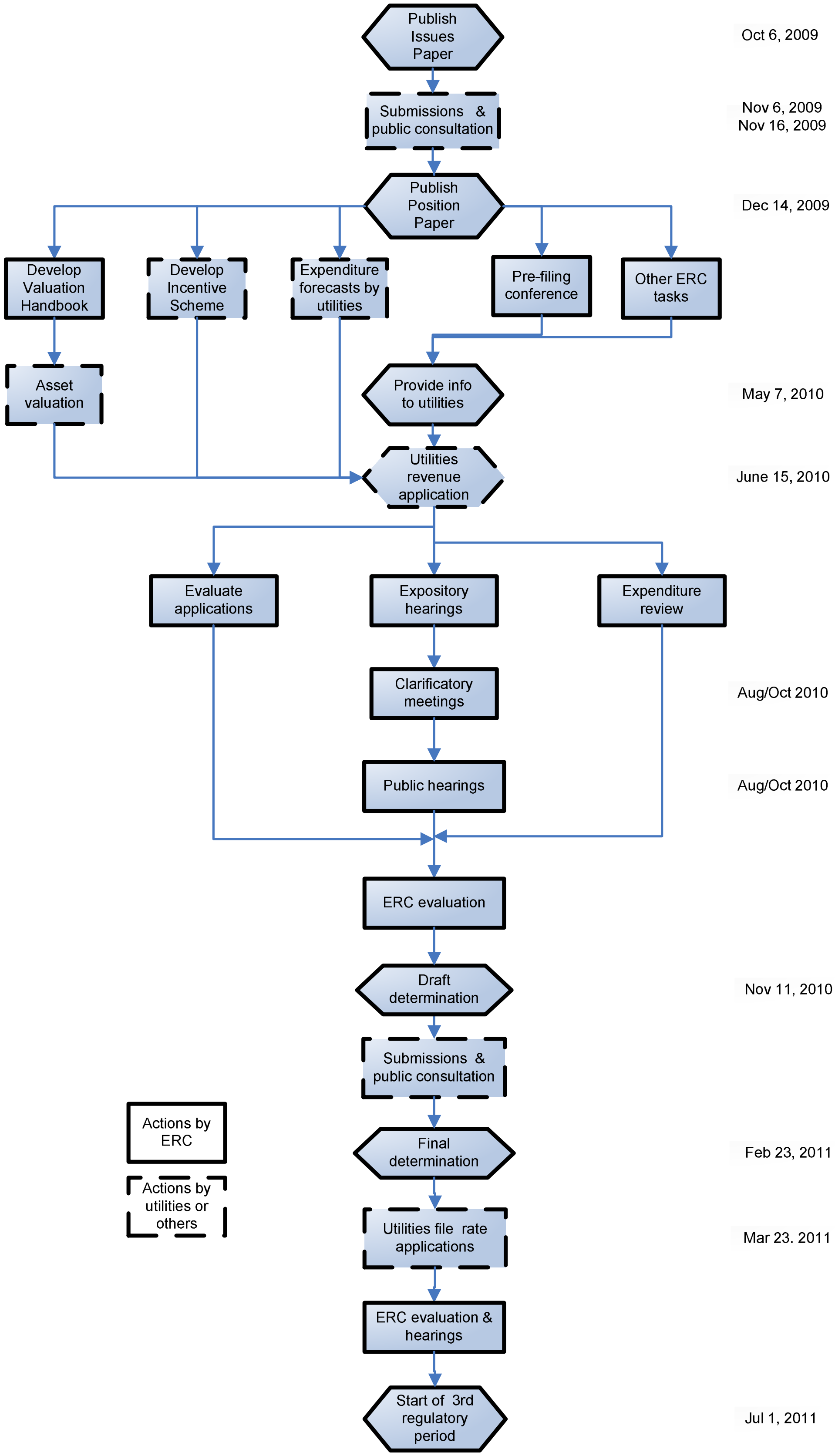
d) Spreadsheet models in which a Regulated Entity's historical and forecast capital expenditure data has to be submitted. These models will make provision for forecasts of local and international expenditure, as well as the conversion of real values to nominal values (or vice versa where applicable). In addition, the models will make provision for a breakdown of expenditure into renewal, growth and refurbishment categories.

e) Guidelines for the submission of expenditure forecasts, including an indication of the information that is required to support these forecasts.

f) Guidelines for the submission of a performance incentive scheme, including an indication of the supporting information that will be required for this.

g) Spreadsheet-based financial model that will be used by the ERC to determine the price-control arrangements for the Third Regulatory Period.

Figure 3.1 : Flowchart of the Regulatory Reset Process for First Entry Group



3.2.2 Valuation Handbook

As discussed in Section 5.1.1, the ERC will develop an ODRC valuation handbook (Valuation Handbook) that will set out detailed guidelines for the valuation of the Regulatory Asset Base for all Regulated Entities for the Third Regulatory Period and the manner in which this is to be audited and presented to the ERC. This handbook will be subjected to full public consultation prior to its issuance.

Each Regulated Entity will conduct the valuation of its Regulatory Asset Base in accordance with the Valuation Handbook, with the results forming part of its Revenue Application. The ERC will review the asset valuation as part of its overall review of the Revenue Application. Full details of the manner in which this review will be conducted, and the required levels of accuracy, will be provided in the Valuation Handbook.

3.3 A note on interpreting Regulatory Years

The Third Regulatory Period for the First Entry Group starts on July 1, 2011, will have a four-year duration, and ends on June 30, 2015. The four Regulatory Years are therefore the four 12-month periods from July 1, 2011 up to June 30, 2015.

A Regulatory Year is referred to in terms of the year in which it ends - i.e. Regulatory Year 2013 is the 12-month period starting on July 1, 2012 and ending on June 30, 2013. This is also referred to as RY2013.

3.4 Appointment of regulatory reset experts

The RDWR confer on the ERC the right or obligation to retain a Regulatory Reset Expert or Experts in relation to a number of matters, including:

a) determining the Regulatory WACC (Clause 4.11 of the RDWR);

b) undertaking a review of asset re-valuation and the preparation of a report in this regard (Clause 4.8 of the RDWR);

c) preparing a report on the condition of assets used to provide Regulated Distribution Services and the regulatory life that should be attributed to these assets (Clause 4.10.3 of the RDWR);

d) reviewing the capital expenditure forecasts of Regulated Entities (Clause 4.12 of the RDWR);

e) reviewing the operating and maintenance expenditure of Regulated Entities (Clause 4.13 of the RDWR);

f) reviewing the energy delivery forecasts provided by Regulated Entities (Clause 4.22); and

g) any other matter in respect of which the ERC determines it requires assistance for the Regulatory Reset Process.

The fees for the Regulatory Reset Expert or Experts must be borne by the Regulated Entities. The terms under which the fees are shared are described in a memorandum of agreement between the ERC and all the current and future entrants into PBR.[11]

The conditions for engagement of a Regulatory Reset Expert or Experts are described in Article XIV of the RDWR. This includes a description of the expertise required and the manner in which the fees for the Regulatory Reset Expert or Experts will be recovered from Regulated Entities.

Appendix C to the RDWR sets out the criteria for the required experience and qualifications of Regulatory Reset Experts.

The ERC gives notice that in terms of the above, it intends to use Regulatory Reset Experts for various activities related to the Regulatory Reset Process, as will be notified to the regulated Entities from time to time.

[11] The bulk of the distribution utilities are contractually represented by the Private Electric Power Operators Association Inc. (PEPOA).

4. OPERATING AND MAINTENANCE EXPENDITURE

As discussed in Section 2, one of the key building blocks in the calculation of the annual revenue requirement for Regulated Entities, is an allowance for efficient operating and maintenance expenditure. Clause 4.14 of the RDWR outlines the requirements for the historical information and the forecasts of operation and maintenance expenditure that Regulated Entities have to provide to allow the ERC to assess the efficiency of this expenditure.

4.1 Basis of operating and maintenance expenditure forecasts

4.1.1 Definition of operating and maintenance costs

For purposes of the Regulatory Reset Process, operating and maintenance costs are defined as those reasonable and efficient costs incurred by a Regulated Entity to effectively and safely operate a Regulated Distribution System and to maintain its asset base to allow it to remain serviceable at rated capacity for its normal expected life. It specifically excludes expenses incurred directly for the creation or establishment of fixed assets that form part of the Regulated Distribution System or Regulatory Asset Base, such expenses which are discussed in Section 5.2 below. It also excludes the depreciation of the Rolled-forward Regulatory Asset Base, which is discussed in Section 5.4 below.

A diagram of the operating and maintenance expenditure of a Regulated Entity is provided in Figure 4.1 below. The operating and maintenance costs covered under the RDWR and addressed in this Position Paper relate only to that for the Regulated Distribution Service grouping.

As noted in Section 1.3, the distribution wheeling rates determined in terms of the RDWR cover the following regulated services:

- Regulated Distribution Services;
- Distribution Connection Services (until such time that these are deemed Excluded Services); and
- Regulated Retail Services.

Only those operating and maintenance costs related to the provision of these services are therefore to be included in the expenditure estimates provided by Regulated Entities for the determination of distribution wheeling rates.

Figure 4.1: Breakdown of Regulated Entity operating and maintenance expenditure

REGULATED ENTITY OPERATING & MAINTENANCE EXPENDITURE				
NON-DISTRIBUTION RELATED ACTIVITIES	**DISTRIBUTION RELATED ACTIVITIES**			
	EXCLUDED AND NON-REGULATED SERVICES	**OPERATING & MAINTENANCE EXPENDITURE RECOVERED UNDER DISTRIBUTION WHEELING RATES**		
		Regulated Distribution Services	**Distribution Connection Services (where not deemed excluded)**	**Regulated Retail Services**
	Services including: • Non-regulated Retail Services • Non-distribution telecommunication network • Excluded Distribution Connection Services • Wholesale aggregation services • Supplier of Last Resort services	Services including: • Electricity conveyance through the Regulated Distribution System • Planning, installation, maintenance, augmentation and operation of the Regulated Distribution System • Administration & general management of the Regulated Distribution Services part of the business of a Regulated Entity • Distribution ancillary services • Distribution IT • Street- and area lighting • Regulated Distribution System control, metering & telecommunications	Services including: • Provision of capability at a Connection Point • Electricity conveyance through Distribution Connection Assets • Planning, installation, maintenance, augmentation and operation of Distribution Connection Assets	Services including: • Billing and collection • Customer support • Collection of bad debt • Energy trading • Electricity sales (excluding generation & transmission costs) • Planning, installation, maintenance, augmentation and operation of consumer metering installations • Consumer meter reading

4.1.2 Expense categories

As part of their Revenue Application, Regulated Entities have to provide their forecast operating and maintenance expenditure broken down into the categories described in Clause 4.13.1 of the RDWR. Forecasts have to be provided for each Regulatory Year of the Third Regulatory Period, as well as the final year of the Second Regulatory Period which, at the time of the Revenue Application, will not be completed.

These categories are listed below (more detailed explanations of each are included in appendix B). As noted in Section 3.2.1, the ERC will provide Regulated Entities with pro forma operating and maintenance expenditure spreadsheet models prior to the filing date of the Revenue Application, which will be broken down into these categories.

a) Regulated Distribution Services

i. Operation

- Operation supervision and engineering
- Contractor services
- Load Dispatching

- Structures
- Substations
- Overhead lines & devices
- Underground cables & devices
- Street Lighting and Signal System (non-roadway and roadways)
- Metering (distribution network related)
- Rents
- Information technology (distribution network related)
- Miscellaneous

ii. Maintenance

- Maintenance supervision and engineering
- Contractor services
- Structures
- Substations
- Overhead lines & devices
- Underground cables & devices
- Street Lighting and Signal Systems System (non-roadway and roadways)
- Distribution transformers
- Information technology (distribution network related)
- Metering (distribution network related)
- Miscellaneous

iii. Administrative and general

- Company Management costs
- Administrative and General Salaries
- Office Supplies and Expenses
- Information technology (admin & general)
- Outside Services Employed
- Property Insurance
- Injuries and Damages
- Employee Pension and Benefits
- Regulatory liaison and compliance
- Rents
- Maintenance of Office and General Plant
- Officers Allowances and Benefits
- Travel
- Training

- Water & Electricity
- Miscellaneous
- WESM compliance – market fees[12]
  - Registration fees
  - Metering fees
  - Billing and settlement fees
  - Administration fees
  - Costs for the PEM Board, committees & working groups
  - Market Management Software and upgrades costs recovery
  - WESM – provision and maintenance of security[13]

b) <u>Distribution Connection Services</u>

i. Operation

- Supervision and engineering
- Contractor services
- Structures
- Substations
- Overhead lines & devices
- Underground cables & devices
- Consumer installations
- Information technology (distribution connection services related)
- Miscellaneous

ii. Maintenance

- Maintenance supervision and engineering
- Contractor services
- Structures
- Substations
- Overhead conductors & devices
- Underground cables & devices
- Consumer installations
- Distribution transformers
- Information technology (distribution connection asset related)
- Miscellaneous

iii. Administrative and general (connection services only)

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[12] Only to the extent that these costs apply to Regulated Distribution Services

[13] Distribution Utilities are mandated to source at least 10% of their power requirements from the Spot Market

- Administrative and General Salaries
- Office Supplies and Expenses
- Information technology (admin & general)
- Outside Services Employed
- Property Insurance
- Injuries and Damages
- Employee Pension and Benefits
- Regulatory liaison and compliance
- Rents
- Maintenance of Office and General Plant
- Officers Allowances and Benefits
- Travel
- Training
- Water and electricity

c) <u>Regulated retail services</u>

- Administrative and General Salaries
- Office Supplies and Expenses
- Outside Services Employed
- Property Insurance
- Injuries and Damages
- Employee Pension and Benefits
- Regulatory liaison and compliance
- Rents
- Maintenance of Office and General Plant
- Officers Allowances and Benefits
- Travel
- Training
- Water and electricity
- Planning, installation and maintenance of consumer metering installations
- Consumer Meter Reading Expenses
- Information technology (retail related)
- Consumer Records, Billing and Collection Expenses
- Bad debts
- Informational and Instructional Advertising Expenses
- Energy trading expenses (excluding energy purchases)
- Miscellaneous Consumer Services Expenses

It will be noted that information technology appears as an item in all main expense categories. This expenditure will be differentiated as follows:

a) Regulated Distribution Services IT systems are systems dedicated directly to supporting the efficient operation and maintenance of Distribution Networks.[14]

b) Distribution Connection Services IT systems are systems dedicated directly to supporting the efficient operation and maintenance of Distribution Connection Assets.

c) Consumer related IT systems are those dedicated to providing and supporting Regulated Retail Services.

d) Administrative and general IT systems are those that contribute to the overall management and benefit of a Regulated Distribution System, but are not directly used in the operation of Distribution Systems.[15] This is further differentiated into support for Regulated Distribution Services or for Distribution Connection Services.

Where IT systems are shared between these functions, a proportional allocation should be made of the expenses for each. Details of the manner in which such costs are allocated should be provided.

Where administrative and management support services are shared between business functions, a proportional allocation should be made of the expenses for each. Details of the manner in which such costs are allocated should be provided.

Following the changes that are being adopted by the ERC in the manner in which system losses are recovered, a Regulated Entity's own consumption of electricity will no longer be separately recoverable as a pass-through cost to consumers. Electricity consumption incurred in the normal course of the business, in as far as this is required for the provision of Regulated Distribution Services, Distribution Connection Services and Regulated Retail Services, will be deemed an operating expense of a Regulated Entity[16]. For purposes of the expense categories, electricity and water consumption have now been separated out.

Given the level of information required and the complexity of analyzing expenditure of limited materiality, the ERC will not require a detailed review of expenses in the various "Miscellaneous" categories indicated above, unless these expenses exceed 5% of the total forecast operating and maintenance expenditure for any forecast year of its specific category. Where this 5% level is expected to be exceeded, expenditure forecasts for the item have to be provided for each of the forecast years.

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[14] This would include the hardware and software used for applications such as geographic information systems, asset databases, fault monitoring and recording, SCADA and network performance data recording.

[15] Such IT systems would include the hardware and software for accounting, payroll or human resource management.

[16] The cost at which electricity consumption is charged as an operating expense should be at normal commercial rates applicable to business similar in size and nature to the Regulated Entity.

4.1.3 Expenses associated with providing metering services

In terms of the DSOAR (Clause 2.11.1), all metering equipment shall be furnished and installed by the Distribution Utility. However, in terms of Clause 4.5.2 of the DSOAR, energy meters used for measuring consumption for customers in the Contestable Market may be owned either by end-consumers or by Distribution Utilities.

For purposes of the operating and maintenance expenditure to be included as part of the Regulated Entities' expenditure forecasts in terms of the RDWR, only those expenses related to providing metering services for customers in the captive market shall be included, as Regulated Retail Services. The DSOAR also indicates that meters are not part of Distribution Connection Assets and metering therefore does not form part of Distribution Connection Services.

Metering services supplied to customers in the Contestable Market or those connected under the Supplier of Last Resort provision do not form part of the operating and maintenance expenditure to be assessed in terms of the RDWR, even where this equipment is owned by a Regulated Entity and it therefore has to provide the associated service.[17]

4.1.4 Meter testing expenditures

The Magna Carta indicates that all electric meters should be tested on a two-yearly basis. However, on reconsideration, the ERC believes that, given the relatively small benefit such regular testing holds for consumers and the large costs associated with testing all meters, this position should be reassessed. The ERC will pursue this as a separate case.

In the interim, for the Third Regulatory Period, Regulated Entities will not be required to conduct blanket meter testing on a two-yearly basis. The only meter-testing costs that will be considered for inclusion in the Distribution Wheeling Rates will therefore relate to a Regulated Entity's normal metering requirements, as supported by historical data on meter failure and testing rates and associated expenditure.

4.1.5 Isolation of CPI and foreign exchange impacts

Revenue requirements will be based on Philippine Peso forecasts made in nominal terms.[18] However, to allow the ERC to isolate and assess the impact of CPI and foreign exchange movements on the forecast expenditure, this also has to be broken down into real Philippine Peso and real US dollar expenditure.[19]

The mechanism for converting the forecast real expenditure to nominal expenditure and foreign expenditure to the local equivalent, is described in Figure 4.2 below. For purposes of this calculation, all expenses to be incurred in other foreign currencies have to be converted to a US dollar equivalent, indicating the exchange rates used.

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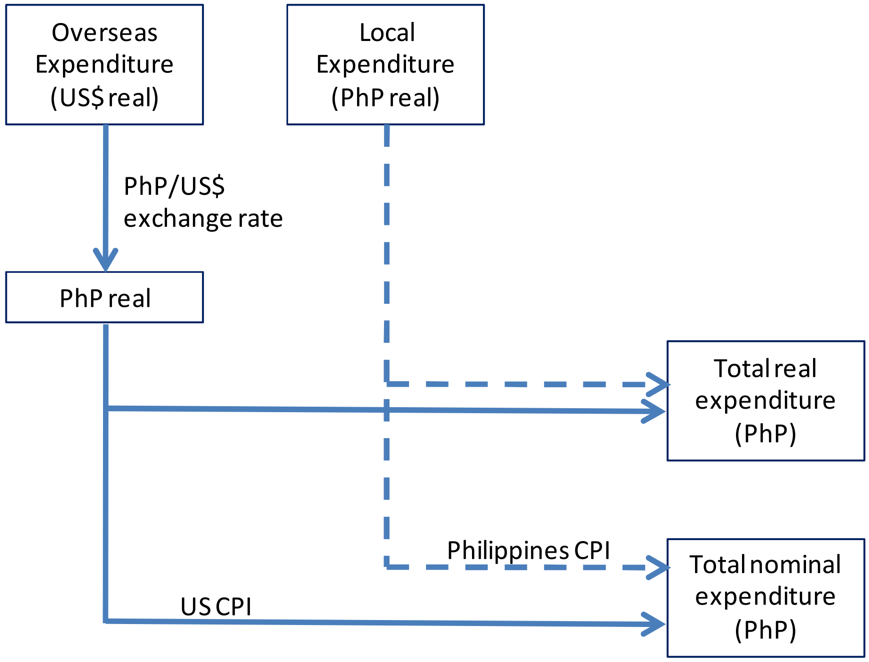
[17] Since these are not regulated services, recovery of metering expenses are excluded from distribution wheeling rates and should therefore form part of the metering charges negotiated with customers in these classes.

[18] The word "nominal" is used in this document in its financial context. It implies that the amount forecasted to be spent takes into account inflation. Where nominal figures are provided for annual forecasts, the 30 June year-end values should be used.

[19] Supra note 7

Figure 4.2: Preparation of PhP Opex forecast



Regulated Entities have to provide full details of their assumptions with regard to forecasts of the Philippine and USA CPI, as well as the future PhP/US$, or any other applicable exchange rates. The sources of these assumptions have to be identified.

The RDWR makes provision in Clauses 4.5.1 and 12.5 for an adjustment to the calculation of the maximum annual price cap for a Regulatory Year following a change in the PhP/US$ exchange rate, where such change exceeds a specified trigger point. While this adjustment is not linked to any specific forecast form of expenditure, it implicitly assumes that a Regulated Entity's operating, maintenance and capital expenditure will change as a result of significant exchange rate changes.

To date, changes in the PhP/US$ exchange rate have been demonstrated to have only a relatively minor (if any) influence on operating and maintenance expenditure by Regulated Entities. This view will be reflected in the ERC's assessment of the weighting to be given to exchange rate changes when determining price caps (see Section 8.2 for further discussion) and adjustments required for determining operating and maintenance efficiency gains (see Section 8 for further discussion).

4.1.6 Historical expenditure patterns

As part of their Revenue Applications, Regulated Entities have to provide the ERC with information on their historical operating and maintenance expenditure in accordance with the requirements of Clause 4.13.1 of the RDWR. The categories into which the expenditure information should be broken down are as discussed in Section 4.1.2 above.

As part of the Revenue Application, records are required for each of the four Regulatory Years up to the year ending on June 30, 2010. The information will be used to support the ERC's assessment of efficient expenditure going forward, as well as to assess possible efficiency gains for which a Regulated Entity may be entitled to a future allowance (as described in Section 9). Historical expenditure is to be provided in nominal terms - that is the actual expenditure incurred in each historical year. (This will be converted to real terms for the purposes of analyzing expenditure trends and evaluating expenditure forecasts.)

In situations where due to abnormal factors, historical expenditure patterns do not provide a fair reflection of what would have been considered efficient expenditure under normal circumstances, this has to be highlighted by Regulated Entities. A full description of the reasons for this claim and the abnormal factors giving rise to it must be provided. An indication also has to be provided of what would have been considered efficient expenditure under normal circumstances.

4.1.7 Allocation of overhead costs

Some Regulated Entities engage in other business activities outside the operation of their Regulated Distribution Systems. These activities are not subject to regulation under the RDWR. This raises questions about the allocation of general management or overhead costs to the various business activities undertaken by a Regulated Entity, and in particular regarding the portion of such costs that are included in the operating and maintenance forecasts submitted by a Regulated Entity as part of the Regulatory Reset Process.

In order to ensure transparency and to allow the ERC to assess the allocation of these expenses, Regulated Entities have to provide full details of the type and magnitude of overhead costs incurred by them that are shared between its regulated and non-regulated activities, the proportion in which these costs have been allocated to the Regulated Distribution System in the operating and maintenance expenditure forecasts (or other expenditure categories), and the basis for this allocation.

For clarity, overhead costs would predominantly, but not exclusively, fall under the category of Administration & General expenses in the Uniform Rate Filing Application. These overhead costs include, but are not limited to those for:

- boards of directors or other governance bodies;
- senior management (where not solely allocated to the management of the Regulated Distribution System);
- business-wide information systems and support staff;
- shared corporate functions such as human resource management or legal support;
- buildings and facilities shared between regulated and non-regulated operating; and
- business-wide insurance.

4.2 Levies, duties and taxes other than corporate income tax

Regulated Entities are entitled to recover most expenses with regard to levies, duties and taxes (other than corporate income tax) incurred in the operation of Regulated Distribution System(s). As part of their Revenue Application, Regulated Entities must provide the ERC with a forecast of the expected payments that will be made for such taxes, levies and duties for each Regulatory Year of the Third Regulatory Period. Budget figures also have to be provided for the final year of the Second Regulatory Period which, at the time of the Revenue Application, will not have been completed.

The required contributions towards the Regulatory Reset Experts appointed by the ERC to assist it with the reset process, is to be included under the levies category. Since this expenditure is not controlled by the Regulated Entities, the ERC will provide forecasts of the allowance that should be included in the Revenue Application.

Note that franchise taxes or levies are specifically excluded from the building block calculation, since this is treated as a pass-though cost.

In addition, in their Revenue Applications, Regulated Entities must provide historical figures for the payment of such taxes, levies and duties for each of the four regulatory years ending on June 30, 2010.

This information is to be provided at the same time as the forecasts for future taxes, levies and duties expenditure are submitted.

4.2.1 Penalty payments on late payments relating to other taxes

In terms of the RDWR (clause 1.3, definition of "Relevant Tax"), costs incurred by a Regulated Entity as penalties, charges, fees and interest on late payment or deficiencies in payment relating to any Tax, is not considered to form a Relevant Tax. As such, these costs cannot be recovered as part of a Regulated Entity's Distribution Wheeling Rates.

The ERC however notes that in some instances penalty or similar payments may arise as a result of a challenge posed by a Regulated Entity to a tax authority on a particular tax imposed. In some situations, certain taxes may not be reasonable or appropriate to a Regulated Entity and it would therefore be remiss of the Regulated Entity, and to the detriment of its consumers, if such a tax is merely accepted and passed through to consumers, instead of the Regulated Entity further investigating and possibly challenging the Tax. However, such a challenge may, after testing in court, not succeed, in which case penalty payments may become due.

The ERC will consider the inclusion of such penalty payments in the Distribution Wheeling Rates based on its consideration of the submission by a Regulated Entity and the reasonableness of a challenge posed by a Regulated Entity. The submission has to set out full details of the case and the reasons for challenging a particular tax.

4.3 Evaluation of operating and maintenance expenditure forecasts

Each category of the operating and maintenance expenditure forecasts submitted by Regulated Entities must be accompanied by a justification of why the expenditure is necessary and why it is considered of reasonable magnitude. The justifications are also to demonstrate how operating efficiencies and productivity will be improved during the Third Regulatory Period.

The ERC will evaluate the information submitted as part of its approval of allowed operating and maintenance expenditure during the Third Regulatory Period. As such it is important also to the Regulated Entities that sufficient supporting information is provided – if the need for expenditure is not sufficiently demonstrated or justified, it is likely that this will be not be approved.

4.3.1 Benchmarking and alternative methods to analyze efficiency

The RDWR notes that international or local benchmarks may be used to compare the operating and maintenance performance of a Regulated Entity to justify expenditure. Benchmarking can be done in terms of cost comparisons, or of any other appropriate performance measure. Where Regulated Entities intend to use such benchmarks, the sources of information, the international companies against which performance has been benchmarked and the benchmarking methodology must be clearly explained.

While it is noted that benchmarking is widely used internationally to evaluate efficiency levels, the ERC has some concern about the general validity of such benchmarking studies where local operating and maintenance practices are compared with those of international companies operating in very different markets and environments, or with significantly different consumer densities, energy consumption patterns and network configurations. Regulated Entities must therefore demonstrate why the particular companies used as reference in a benchmarking study were considered appropriate. Regulated Entities must also indicate how the results of the study were normalized or adapted for the particular characteristics of each Regulated Distribution System.

Notwithstanding the potential problems noted above, the ERC may also decide to use benchmarking as one of its means to evaluate the operating and maintenance expenditure forecasts of a Regulated Entity. Such benchmarking is likely to include expenditure or other performance comparisons with that of other privately owned Philippines Distribution Utilities, which the ERC believes may in most cases be more appropriate than using international benchmarks.

Regulated Entities may also consider alternative methods to demonstrate the efficiency of their proposed operating and maintenance forecasts. Without being prescriptive in this regard, such methods could include :

- a bottom-up approach, whereby expenditure requirements are estimated based on assessing all the operating and maintenance actions required to ensure the efficient operation of a Distribution System and the reasonable cost for each such action based on the personnel and equipment involved; or
- analysis of historical operating and maintenance expenditure patterns, taking into account the historical efficiency and the potential that existed for efficiency improvements without substantially reducing service levels.

If an alternative method is applied to establish the efficiency of forecast operating and maintenance expenditure, Regulated Entities are to provide full details of the methodology applied, their calculations and the supporting information used.

4.3.2 Trade-off between capital and operating expenditure

The ERC recognizes that in maintaining network service performance and reliability levels, there is potential for a substantial degree of trade-off between the operating and capital expenditure incurred by a Regulated Entity, especially in the shorter term.[20] When considering the efficiency of forecast operation and maintenance expenditures, the ERC will therefore also take note of the efficiency of the forecast capital expenditure. (See Section 5.2 for a discussion on capital expenditure forecasts.)

Where Regulated Entities explicitly intend to make, or foresee the need for such trade-offs, this is to be highlighted in their rate applications. The justification for the intended trade-offs is also to be described.

4.3.3 Review of operating and maintenance expenditure forecasts

A review team will be created to review the operating and maintenance expenditure forecasts (including the taxes, levies and duties noted in Section 4.2) and supporting documentation submitted by each Regulated Entity. This team will be made up of internal ERC staff and one or more Regulatory Reset Experts retained in terms of Article XIV of the RDWR. The review team will consider whether these forecasts :

a) are reasonable and efficient;

b) are supported by adequate justification;

c) are sufficient to support the forecast growth of connections, energy delivered or co-incident peak demand;

d) are sufficient to maintain or improve existing Regulated Entity service performance or Distribution System reliability levels;

e) are reasonable with regard to the recovery of bad debt and the strategy for improving debt collection; and

f) make a reasonable allowance for forecast changes in CPI or exchange rate levels.

One of the aspects that the review team will focus on is the level of benefits accorded to staff by the Regulated Entities. The ERC recognizes that these benefits may be set in terms of internal negotiations and agreements at any level desired by a Regulated Entity, but will not allow recovery of costs from customers for benefits in excess of legal requirements (in terms of the prevailing employment law).

The review team will recommend to the ERC the level of operating and maintenance expenditure forecasts for the Third Regulatory Period that is considered appropriate for each Regulated Entity.

Following consideration of this advice, the ERC will decide whether the Regulated Entities' proposed operating and maintenance expenditure forecasts and the factors on which they are based meet these criteria and, if this is the case, will approve the forecast expenditures. If the ERC decides that the criteria have not been met by a Regulated Entity, it will consult further with that entity and approve such forecasts as it considers necessary for the criteria to be met.

[20] It would for example be possible to defer renewal or refurbishment of assets, both of which constitute capital expenditure, by applying more operating or maintenance resources to the assets in question. It would also be possible to reduce operating and maintenance expenditure by investing more in new, larger or modern assets.

4.4 Impact of operating and maintenance expenditure on service levels

The ERC is keen on understanding the impact of operating and maintenance expenditure on the service performance of Regulated Entities or the performance of Distribution Systems. Regulated Entities should therefore indicate whether their operating and maintenance forecasts provide for maintaining current performance levels, or whether they include some provision for improved performance levels.

4.5 Data requirements

As noted in Section 3.2.1, at the pre-filing conference, the ERC will provide Regulated Entities with spreadsheet-based templates on which their data submissions, including that relating to operating and maintenance expenditure, should be made. These templates will make provision for the expenditure categories identified above and will also make provision for entering CPI and exchange rates, and will automatically convert real expenditure to nominal, or vice versa as required.

5. DEPRECIATION AND RETURN ON CAPITAL

Further key building blocks supporting the calculation of the revenue requirements of Regulated Entities are the recovery of capital invested in Distribution Systems, and the provision of an appropriate return on capital invested. This requires an assessment of the reasonable asset valuation of the Regulatory Asset Base, the appropriate rate of return that should be earned on this asset value and the depreciation of such value.

In addition, future capital investments in Distribution Systems and disposal of assets have to be assessed for efficiency and optimization.

5.1 Regulatory Asset Base

5.1.1 Valuation of the Regulatory Asset Base

In Clauses 4.8 and 4.9 of the RDWR, the methodology that will apply in establishing the value of the Regulatory Asset Base for each Regulated Entity is described.

An asset re-valuation must be undertaken for each Regulated Distribution System, which will culminate in a Re-valuation Report for each Regulated Distribution System. This is to be completed at the latest 13 months before the start of the Third Regulatory Period. The asset valuations will be undertaken using an optimized depreciated replacement cost (ODRC) approach.

The re-valuated opening value established in a Re-valuation Report will be for a Regulatory Asset Base as it exists at the Re-valuation Date, which will be set at December 31, 2009 for the Third Regulatory period for the First Entry Group. The Rolled-forward Depreciated Regulatory Asset Base at the start of the Third Regulatory Period will be calculated by the ERC after making allowance for efficient capital expenditure, asset depreciation and asset disposals during the period after the Re-valuation Date and the start of the Third Regulatory Period.

The value of the Regulatory Asset Base, rolled forward during the Third Regulatory Period, will be the basis on which a Regulated Entity's reasonable return on capital to be recovered as part of its annual revenue requirement, will be determined. The process for determining the Rolled-forward Depreciated Regulatory Asset Base is illustrated in diagram form in Figure 5.1 below.[21]

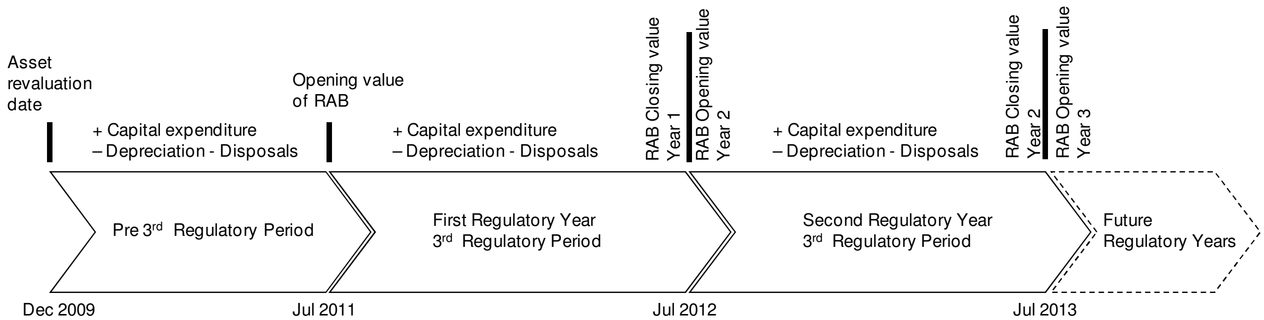
For the purposes of the Re-valuation of a Regulatory Asset Base during the Third Regulatory Period, the ERC will appoint a Regulatory Reset Expert to assist it to develop an ODRC valuation handbook (the Valuation Handbook). This Valuation Handbook will apply to all Regulated Entities at all Entry Points in the Third Regulatory Period. By using a Valuation Handbook, there will be consistency in valuations across the Philippines, efficient investment behaviour will be encouraged[22] and also the quantum of cost and work

[21] It should be noted that in terms of the RDWR, the "disposals" component indicated in Figure 5.1 is actually included in the calculation of the regulatory depreciation. However, the impact on the calculation of the Regulatory Asset Base is the same.

[22] The Valuation Handbook will reflect efficient application of assets and asset types, as would be constructed by a hypothetical efficient utility, constructing a new distribution network in a "brownfields" area.

required in re-valuing the Regulatory Asset Base of all 18 Regulated Entities during the Third Regulatory Period will be reduced. The Valuation Handbook will be suitable to allow the valuation of the Regulatory Asset Base by either the ERC and its Regulatory Reset Expert, or a Regulated Entity and its independent appraisal company.

Figure 5.1: Rolled-forward Depreciated Regulatory Asset Base



The Valuation Handbook will specify:

(i) the ODRC valuation guidelines that will be adopted for the Third Regulatory Period, including the optimization principles;

(ii) standard asset types and standard replacement costs for assets commonly used by Regulated Entities in providing Regulated Distribution Services, Distribution Connection Services or Regulated Retail Services;

(iii) standard asset lives for these commonly used asset types;

(iv) multiplier ranges that will account for differences between various Distribution Systems or parts of Distribution Systems arising from the environment in which networks are installed (e.g. CBD or dense commercial, medium commercial, dense residential, normal residential or barangays, and rural areas) or the geological nature of the area in which networks are installed (rock, hard soil or soft soil);

(v) other factors that should be added to account for exceptional factors influencing network replacement costs, such as exceptional traffic density, exceptional population density, exceptional vegetation density or areas requiring exceptional safety precautions;

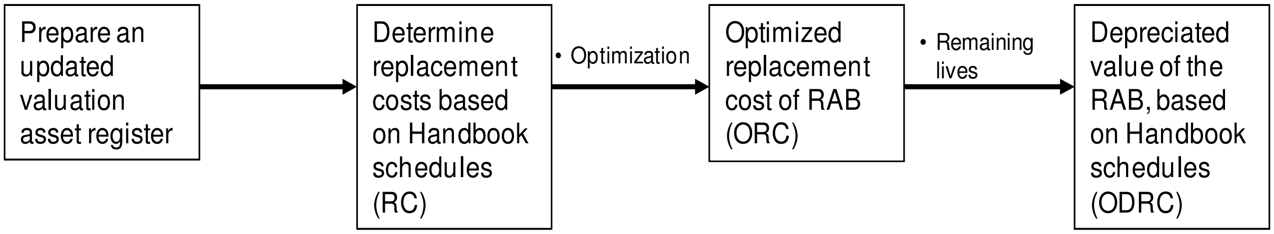
(vi) the manner in which standard replacement costs will be escalated from the initial values indicated in the Handbook; and

(vii) the treatment of non-standard assets that are not listed in the standard replacement cost schedules, or of assets installed in special circumstances.

The Re-valuation for the First Entry Group will be conducted for the Regulatory Asset Base as it exists on December 31, 2009 (the Re-valuation date).

The publication date of the Valuation Handbook will be not later than April 22, 2010, after full public consultation with all interested parties. By applying the Valuation Handbook, the valuation process will be limited to the steps described in Figure 5.2 below.

Figure 5.2: Steps in determining the revaluated asset values, using a Valuation Handbook



These steps and the actions supporting them are described in more detail below.

5.1.2 Preparation of the valuation asset register

As an initial step a fixed asset register must be prepared for the purpose of the valuation. (A concomitant, secure data base system to set up the initial fixed asset data base, update the data base and generate the register and other necessary reports shall be developed and implemented. This will be done in conjunction with each Regulated Entity.) This register will record the details of all assets in use on a Regulated Distribution System, including the asset age and the location and environment in which they are installed. Asset utilization information is also to be recorded (for optimization purposes).

Where considered suitable, the valuation registers used for the Second Regulatory Period could be used as basis for the new registers, updated to reflect assets created since the Initial re-valuation date for the Second Regulatory Period, and disposed assets.

5.1.3 Asset to be valued

The main Distribution System function of most Regulated Entities is the provision of Regulated Distribution Services and most of the assets they own or control are therefore applied for this purpose. However, Regulated Entities also conduct any number of non-regulated activities which may or may not be associated with electricity distribution, using assets that are separate from the Regulated Distribution System assets, or making use of these assets. As noted in Section 1.3 the Regulatory Reset Process and the RDWR is limited to the provision of the following services and the associated Regulatory Asset Base:

- Regulated Distribution services;
- Distribution Connection Services; and
- Regulated Retail Services.

For the Regulatory Reset Process, the Regulatory Asset Base is defined as those assets required by a Regulated Entity for the efficient provision of these services. It refers to the Distribution System assets, Distribution Connection Assets as well as those Non-network Assets required to support the delivery of the services. In Figure 5.3 below, a diagram is provided of the Regulatory Asset Base in relation to the total assets that could be owned or managed by a Regulated Entity.

It should be noted that generation assets, where such assets are used to generate electricity for resale or to provide ancillary services that are on-sold to a transmission service provider or any other user of such services, do not form part of the Regulatory Asset Base. However generators may be used solely for distribution purposes, such as providing voltage support, reactive VAR compensation, demand peak lopping or providing standby power during planned interruptions or emergency situations. In such cases, where no direct revenue is derived from selling the energy generation or ancillary capacity of generators, such generators are to be included under the Regulated Distribution Assets and their cost, including the forecast operating and maintenance costs, would be recovered through the distribution wheeling rates. Regulated Entities should provide full details of all such generators included as part of the Regulatory Asset Base or included as operating and maintenance expenditure.[23]

Figure 5.3: Breakdown of the Regulatory Asset Base

<table>
<tr><th colspan="5">REGULATED ENTITY ASSET BASE</th></tr>
<tr><th>NON-DISTRIBUTION RELATED ASSETS</th><th colspan="4">DISTRIBUTION RELATED ASSETS</th></tr>
<tr><td rowspan="3">Assets owned by the Regulated Entity but not used to provide Distribution or Related Services. This includes:
• Generation assets
• Other investments
• Non-related subsidiary businesses</td><th>EXCLUDED AND NON-REGULATED SERVICES ASSETS</th><th colspan="3">REGULATORY ASSET BASE</th></tr>
<tr><td></td><th>Regulated Distribution Assets</th><th>Distribution Connection Assets (where not deemed excluded)</th><th>Regulated Retail Services Assets</th></tr>
<tr><td>Assets for providing:
• Non-regulated Retail Services
• Non-distribution telecommunication services
• Excluded Distribution Connection Services
• Wholesale aggregation services
• Supplier of Last Resort services</td><td>Assets for providing :
• Electricity conveyance from bulk or embedded generation connection points to end-user connection points
• Administration & general management of the Regulated Distribution Services part of the business of a Regulated Entity
• Distribution ancillary services
• Distribution IT
• Street- and area lighting
• Regulated Distribution System control, metering & telecommunications
• Transferred subtransmission assets</td><td>Assets for providing:
• Capability at a Connection Point
• Conveyance of electricity
• Planning, installation, maintenance, augmentation and operation of Distribution Connection Assets</td><td>Assets for providing:
• Billing and collection
• Customer support
• Collection of bad debt
• Energy trading
• Electricity sales (excluding generation & transmission costs)
• Consumer metering installations</td></tr>
</table>

As noted before in the discussion of operating & maintenance expenditure (Section 4.1.3), in terms of the DSOAR (Clause 2.11.1), all metering equipment shall be furnished and installed by the Distribution Utility. However, in terms of Clause 4.5.2 of the DSOAR, energy meters used for measuring consumption for customers in the Contestable Market may be owned either by end-consumers or by Distribution Utilities.

For the purposes of the Regulatory Asset Base, all metering equipment used for customers making up the captive market, shall be included as Regulated Retail Services Assets. The DSOAR also indicates that meters are not part of Distribution Connection Assets.

[23] Note that this does not apply to generation that is used on a permanent or semi-permanent basis. Such cases fall outside the Regulated Distribution Services and utilities may have seek other redress from the ERC to cover the costs associated with such generation.

Metering equipment supplied for customers in the Contestable Market or those connected under the Supplier of Last Resort provision does not form part of the Regulatory Asset Base, even where this equipment is owned by a Regulated Entity.[24]

5.1.4 Asset categories

Clause 4.8.8 of the RDWR specifies the categories into which the assets making up a Regulated Distribution System must be subdivided for re-valuation purposes. The Re-valuation Report must specify the value of the assets against each of these categories, as well as the information used and assumptions made against each category. If considered necessary, Regulated Entities can break down asset information into further subcategories (under the main headings provided here). The asset categories to be used are:

a) Regulated Distribution Services Assets

i. Distribution services

- Land and Land Rights (dedicated to distribution purposes)
- Structures and Improvements (dedicated to distribution purposes)
- Substation Equipment
  - Power transformers
  - Switchgear
  - Protective equipment
  - Metering and control equipment
  - Communications equipment
  - Other station equipment
- Poles, Towers and Fixtures
- Overhead Conductors and Devices
- Underground Conduits
- Underground Conductors and Devices
- Distribution transformers
- Power conditioning equipment[25]
- Meters, Metering Instruments & Metering Transformers (dedicated to distribution purposes)
- Information technology equipment (dedicated to distribution purposes)
- Regulated Entity property on Consumers' Premises (not forming part of Distribution Connection Assets)
- Street Lights and Signal Systems
- Submarine Cables

[24] Since these are not regulated services, recovery of metering charges, including a reasonable return on the assets, are excluded from distribution wheeling rates and should therefore form part of the metering charges negotiated with customers in these classes.

[25] This refers to equipment such as capacitor banks for power factor correction, voltage regulators, generators used for spinning reserve or voltage stability, VAR compensators etc..

ii. General Plant (Non-network Assets)

- Land and Land Rights (non-network related)
- Structures and Improvements (non-network related)
- Office Furniture and Equipment
- Transportation Equipment
- Stores Equipment
- Tools, Shop and Garage Equipment
- Laboratory Equipment
- Information systems equipment (non-network related)
- Power-operated Equipment
- Communication Plant and Equipment
- Miscellaneous Equipment

iii. Materials and Supplies, including spares

iv. Transferred Subtransmission Assets

b) <u>Distribution Connection Services Assets</u>

i. Distribution services

- Poles, Towers and Fixtures
- Overhead Conductors and Devices
- Underground Conduits
- Underground Conductors and Devices
- Distribution Transformers
- Information technology equipment (dedicated to Distribution Connection Services)

ii. General Plant (Non-network Assets)

- Land and Land Rights (non-network related)
- Structures and Improvements (non-network related)
- Office Furniture and Equipment
- Transportation Equipment
- Stores Equipment
- Tools, Shop and Garage Equipment
- Laboratory Equipment
- Information systems equipment (non-network related)
- Power-operated Equipment
- Communication Plant and Equipment
- Miscellaneous Equipment

iii. Materials and Supplies, including spares

c) Regulated Retail Services Assets

- Meters, Metering Instruments & Metering Transformers – Consumer consumption metering
- Land and Land Rights
- Structures and Improvements
- Office Furniture and Equipment
- Transportation Equipment
- Stores Equipment
- Tools, Shop and Garage Equipment
- Laboratory Equipment
- Information systems equipment
- Communication Plant and Equipment
- Miscellaneous Equipment

The Re-valuation Report must also indicate the weighted average age of the assets in each asset category.

The Non-network Assets will constitute part of the Regulatory Asset Base and have to be included in the Re-valuation Report. However, they will generally not be subject to optimization (unless there is evidence of excessive investment, or asset stranding). In addition, the valuation methodologies described in Section 5.1.8 above may not be appropriate for these assets. The Re-valuation Report should indicate the approach adopted for including and valuing Non-network Assets in the Regulatory Asset Base.

5.1.5 Distribution Connection Assets

Excluded Services are discussed in Section 12.5. As noted before, Distribution Connection Services will eventually be an excluded service, after the full implementation of the DSOAR. Hence Distribution Connection Assets will eventually be excluded from the Regulatory Asset Base and it is important that these be kept separate in the expenditure forecasts and the Re-Valuation Report.

For the present and therefore for purposes of this Position Paper, these assets are still included under the Regulatory Asset Base on which Regulated Entities are entitled to a return under the PBR. This situation will be reviewed by the ERC if full implementation of the DSOAR occurs before the start of the Third Regulatory Period.

5.1.6 Asset database

In order to maintain accurate records of the revalued and historical values of assets as determined during the Re-valuation, as well as the depreciation of these assets going forward, the ERC expects Regulated Entities to maintain a detailed asset database. For purposes of the database, individual assets must be broken down to a meaningful level, to at least a single feeder, transformer or switchboard level. All major substation assets must also be separately indicated. Without being prescriptive about the format that this database should take, which could be GIS (Geographical Information System) records or a dedicated database application, the information below must be included for all assets:

- description of the asset, showing key ratings, installation and configuration details;
- unique asset identifier, to allow an asset to be identified in the field;
- initial installation date of the asset;
- initial historical cost of the installed and commissioned asset, including all costs capitalized against the asset;
- all costs capitalized against the asset after installation, such as for refurbishment;
- historical value of the asset as of the date of the Re-valuation Report;
- optimized value of the asset as of the date of the Re-valuation Report;
- depreciation of the ODRC of the asset, going forward; and
- depreciation of the historical asset value of the asset, going forward.

In Clause 1.7 of the RDWR it is noted that a separate register must be held of any Subtransmission Assets transferred to Regulated Entities by TransCo or NGCP. The proposed asset database should therefore make allowance for these assets to be separately identifiable.

5.1.7 Use of Regulatory Reset Expert for asset valuation

Clause 4.8.2 of the RDWR allows for the asset re-valuation to be undertaken by either:

a) an independent appraisal company engaged by the Regulated Entity that operates the relevant Regulated Distribution System, in which case the ERC must also retain a Regulatory Reset Expert or Regulatory Reset Experts to review the valuation results and the Re-valuation report; or

b) a Regulatory Reset Expert or Regulatory Reset Experts retained by the ERC pursuant to Article XIV for purposes of undertaking that re-valuation (and prepare the Re-valuation report).

The choice is at the discretion of the ERC, after consulting with the Regulated Entities.

It should be noted that for Regulated Entities, the existing guidelines for appraisal, including those for the accreditation of appraisers, as contained in the ERC's "Guidelines for the Appraisal of Property, Plant and Equipment for Rate Fixing Purposes of ERC" has been superseded by the RDWR and the intended Valuation Handbook. Only appraisers with proven skills in the use of the ODRC valuation technique can be retained.

Since a detailed Valuation Handbook will be available to provide consistency of application, the ERC favors option (a), for each Regulated Entity to conduct its own valuation. For this option each Regulated Entity must :

- appoint its own independent appraisal company[26] to conduct the asset valuation in accordance with the Valuation Handbook, or
- prepare its own asset valuation in accordance with the Valuation Handbook, in which case an independent auditor must be appointed to certify that the valuation had been conducted in accordance with the Valuation Handbook and that the results have been correctly determined[27], and
- prepare the Re-valuation Report for submission to the ERC as part of its Revenue Application.

The ERC will retain a single, independent Regulatory Reset Expert or group of Regulatory Reset Expert(s) to assist it with the review of the Re-valuation Reports and the supporting calculations. As part of this review:

- the Re-valuation Report and supporting information will be analyzed in detail;
- supporting calculations will be checked, through a combination of sampling and review;
- spot-checks will be carried out on site to verify the accuracy of the asset registers, condition reports, supporting technical information (including single line diagrams and GIS records where available) and the manner in which asset information is applied for the valuation analysis; and
- the optimization calculations and results will be scrutinized in detail.

The ERC therefore intends to engage such a Regulatory Reset Expert(s) after consulting with Regulated Entities to establish their preferences and the criteria for ensuring the independence of the Expert(s).

5.1.8 Determining the replacement costs

The asset replacement costs will be set in the Valuation Handbook, based on standard replacement rates that will be applicable to all Regulated Entities, after applying multiplier factors to account for differences between Regulated Distribution Systems.

The standard rates and asset lives used in this Valuation Handbook will be developed taking into account the asset valuations carried out on all Regulated Entities during the Second Regulatory Period, as well as further evidence collected on standard asset replacement costs throughout the Philippines. The basis for setting the replacement rates will be those costs that would be incurred by an efficient new entrant, constructing an

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[26] This could be a recognized engineering or economic consultancy, an asset appraisal company, or a combination thereof.

[27] It is recognized that an auditor will generally not be in a position to comment on the accuracy of the asset registers or the information on which it is based. An audit certification will therefore focus on the manner in which information had been processed, the accuracy of calculations and the consistency of the valuation with the requirements of the Valuation Handbook.

electricity distribution network in a brownfields[28] situation, with efficient economies of scale[29] and largely using standard assets commonly in use throughout the Philippines,

5.1.9 Treatment of works under construction at the Re-valuation date

In terms of Clause 4.8.8 of the RDWR, where construction projects have commenced before the Re-valuation date (December 31, 2009) but will only be completed after this date, assets fully completed and commissioned before the date of the Revaluation will be included in the Revaluation Report (unless optimized out in terms of the Valuation Handbook).

Regulated Entities are to provide full information regarding the nature of such projects under construction, assets that will be completed prior to the Re-valuation date and the amounts of capital expenditure incurred against such assets and the dates on which such expenditure have occurred.

5.1.10 Optimization principles

The second step in the asset re-valuation process is to determine the optimized replacement cost (ORC) of the Distribution System asset base. The optimization requirements will be developed for and consulted on as part of the Valuation Handbook, but will essentially be similar to those adopted for the Second Regulatory Period.

Assets optimized out for the Initial Re-valuation prior to the Second Regulatory Period, will be re-included in the regulatory asset base for the Third Regulatory Period if the ERC is satisfied that those assets are required to support the provision of Regulated Distribution Services in respect of that Regulated Distribution System. The following will then apply:

(a) The value at which that asset must be re-included in that regulatory asset base is its Regulatory Asset Base value as at the date of its exclusion from the Regulatory Asset Base.

(b) The asset must be included in the Regulatory Asset Base in the Regulatory Year in the Third Regulatory Period in which the asset is forecasted to be required to support the provision of Regulated Distribution Services in respect of that Regulated Distribution System by the Regulated Entity, and the asset must be depreciated (in an accelerated manner) over its remaining economic life as if it had never been optimized out of the Regulatory Asset Base.

5.1.11 Calculating the ODRC

The final step of the asset re-valuation process involves the determination of the ODRC of the Distribution System asset base. This is done by deducting the regulatory depreciation

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[28] This assumes that a network is newly constructed, but would be built around existing town layouts and have to take into account the practical limitations of the position of the bulk supply network, bulk supply points and load centers.

[29] This assumes that networks would be erected through a relatively small number of substantial construction projects, rather than as a high number of small incremental steps. While this would not necessarily correspond with the actual manner in which existing networks were erected, this methodology is based on deriving efficient asset replacement costs.

from the optimized replacement cost (ORC). The ERC's methodology for the depreciation of the Regulatory Asset Base is discussed in Section 5.4 below.

The Re-valuation Report requires an indication, per asset category, of the weighted average optimized replacement cost and the weighted average ODRC.

5.1.12 Allowance for capital tied up during construction work

The RDWR makes provision for the addition of a factor to the Regulatory Asset Base to compensate Regulated Entities for the time value of capital tied up during the construction of major assets. This is the CWIP factor specified in Clause 4.8.12.

Calculation of the value of capital invested during construction will be based on the "spend profile" for representative construction projects, calculated on a month-by-month basis over the whole planning and construction period of such projects. The Regulatory WACC will be applied to the varying levels of capital tied up during this process, to determine the appropriate return that could otherwise have been earned on the capital. This is considered a fair proxy for the value of the capital tied up in construction projects.

Once a representative sample of projects has been assessed to allow a view to be formed on the value of capital tied up, this has to be translated to a general CWIP factor. Three methods for applying this factor are suggested in the RDWR:

a) uniformly escalating the ODRC values by a constant factor;

b) directly estimating the investment cost for specific part projects and adding this cost to the optimized replacement value of assets; or

c) other methods approved by the ERC.

It is also noted that the CWIP factor may be the same for all revalued assets, or may differ between asset categories.

For the Second Regulatory Period, the ERC adopted a uniform escalation of the ODRC [option (a) above], mainly for the sake of simplicity and because of the lack of sufficient representative information. However, it does not have a clear preference in this regard and indicated that if a compelling case was presented in favor of another method, it may decide to change its approach for the Third Regulatory Period. No such case was presented in the submissions on the Issues Paper and the ERC will therefore adopt the same approach to determining the CWIP factor for the Third Regulatory Period to that used during the Second Regulatory Period.

5.1.13 Initial opening value of the Regulatory Asset Base

The Re-valuation Report will establish the opening value of the Regulatory Asset Base as at the Re-valuation date. Since this date is 18 months before the start of the Third Regulatory Period, for the purpose of deriving the opening value of the Regulatory Asset Base at the start of the Third Regulatory Period, it is necessary to estimate the impact of capital expenditure and depreciation during the period between the Re-valuation Date and the start of the Third Regulatory Period. The process for this consideration is described in Clause 4.8.13 of the RDWR.

The ODRC of the opening Regulatory Asset Base will be the Re-valuation value as established in the Re-valuation Report, plus an allowance for the following costs established during the interim period leading up to the start of the Third Regulatory Period:

- addition of the forecast capital expenditure over the period as approved by the ERC for the last 18 months of the Second Regulatory Period[30];
- deduction of the estimated depreciation of the ODRC value established in the Re-valuation Report over the interim period; and
- deduction of the estimated depreciation of the capital expenditure incurred over the last 18 months of the Second Regulatory Period, from the date of commissioning of the assets on which the expenditure was incurred.

Included in the cost of depreciation is an allowance for the possible disposal of assets included in the opening Regulatory Asset Base. This allowance is calculated as the difference of the value of the disposed assets in the rolled-forward rate base at the time of disposal (the ODRC value at which the assets are recorded in the fixed asset register) and the actual value at which they were disposed of, after deducting any expenses associated with the disposal.

5.1.14 Rolled forward asset base

The Regulatory Asset Base of a Regulated Distribution System for each regulatory year is determined by a roll-forward calculation of the value of each asset category, as described in Clause 4.9 of the RDWR. The value of the Regulatory Asset Base used for calculating the annual revenue requirement of Regulated Entities is the average of the opening and closing values of the Regulatory Asset Base for each regulatory year.

The opening Regulatory Asset Base value at the start of the Third Regulatory Period is the ODRC of the Regulated Distribution System, adjusted for the interim period between the Re-valuation Date and the start of the Third Regulatory Period as discussed in Section 5.1.13 above. The value will be as determined by the ERC in accordance with Clause 4.8.13 of the RDWR.

Subsequently, the closing value of the Regulatory Asset Base for each Regulatory Year is to be based on the opening value for that year plus an allowance for the following estimated costs arising during the Regulatory Year :

- addition of the estimated capital expenditure, as approved by the ERC and discussed in Section 5.2 below;
- deduction of depreciation of the opening Regulatory Asset Base as of the start of the Second Regulatory Period; and
- deduction of depreciation of the capital expenditure incurred on Distribution System assets during the previous years of the Second Regulatory Period.

[30] Where a Regulated Entity has indicated that major capital expenditure is to be deferred, or major unforecasted acquisitions are to be included and this has been approved by the ERC, this capital expenditure value may differ from that initially approved by the ERC in its final determination of the price-control arrangements for the Second Regulatory Period. (See Section 12.2.2.)

As before, allowance is made in the depreciation calculation for the disposal of assets (at the ODRC value at which they were entered at the time in the fixed asset register), minus the actual income received from the disposed asset (after accounting for any expenses incurred during the disposal).

Calculation of depreciation is discussed in Section 5.4 below. Since depreciation will be separately calculated on capital investments made after the start of the Third Regulatory Period, it is necessary to maintain separate records of such asset investments and the depreciation on these assets from that of the opening value of the Regulatory Asset Base at the start of the Third Regulatory Period.

The Rolled Forward Depreciated Asset Base implicitly assumes that all approved future capital expenditure on the Regulatory Asset Base will be at optimized levels. This may not be the actual case and differences between the value of the Regulatory Asset Base for assets procured after the Re-valuation Date and the same asset base included in a Regulated Entity's financial accounting base may therefore arise.

5.1.15 Working capital

In calculating the return on capital included in the annual revenue requirement for Regulated Entities, the RDWR provides for a return on working capital tied up in the Regulated Distribution Systems. The rate of return on this capital is set at the Regulatory WACC. This is to compensate Regulated Entities for the delay between cash flows entering the businesses from customers and those leaving it for suppliers.

Working capital is calculated in accordance with Clause 4.7.7 of the RDWR and is set as a proportion of the difference between real operating and maintenance expenditure and the real amount of bad debts for a Regulated Distribution System.

The proportion is to be determined by the ERC after conducting an analysis of the relevant payables and receivables. Such analysis could take the form of a lead/lag study, a benchmark study or an industry average study. Since the ERC is of the opinion that Regulated Entities have considerable control over the level of working capital tied up in their regulated businesses and should in theory be rolling over in- and outgoing cash-flows in roughly the same period, the proportion should be low, approaching zero.[31]

It is intended that the return on working capital will only be provided on capital applied to the managing and operation of the Distribution System and will not apply to working capital required by Regulated Entities for the payment of transmission, generation or similar charges.[32] However, it is noted that in the interim, until all arrangements for allocating service charges have been finalized, Regulated Entities may be unable to recover such returns and may therefore have to recover this as part of their distribution wheeling

[31] This is especially true since a reasonable level of spares is allowed under the Regulatory Asset Base, on which Regulated Entities are already entitled to fair recovery. Working capital tied up in inventory should therefore not be recovered twice.

[32] The return on working capital required for these types of charges should be included as a separate line item in consumers' accounts or separately included and indicated as part of the relevant charge, following the approval by the ERC of a filing in this regard.

rates, but only in those cases where such recovery substantially lag recovery of the costs from end-consumers.

While the ERC is generally sympathetic to this requirement, it will only approve this recovery if a Regulated Entity can demonstrate that it has implemented all practical means to minimize the collection period of outstanding accounts. In addition, the ERC requires Regulated Entities to investigate the possibility of requiring a deposit amount from all consumers. This would serve not only to safeguard a Distribution Utility against default on payments, but also provide a cash buffer that will offset the working capital tied up in energy and transmission service purchases.

5.1.16 Historical cost of the Regulatory Asset Base

Clause 4.8.14 of the RDWR requires that the Re-valuation Report must also identify the historical cost of the Regulatory Asset Base for a Regulated Distribution System. Such historical costs must also be depreciated in a similar manner to the rolled-forward depreciated Regulatory Asset Base described in Section 5.1.14 above.

The written down historical costs thus determined are used when calculating the corporate income tax building block if not set to zero.

Capital expenditure going forward from the start of the Second Regulatory Period (therefore including the Third Regulatory Period as well) is optimized and depreciated over appropriate life-spans. As the historical cost and ODRC and depreciation rates for assets acquired after the start of the Second Regulatory Period will be the same, it is unnecessary to maintain two sets of regulatory asset records for capital expenditure going forward.

5.1.17 Use of assets not owned by a Regulated Entity

Situations exist where a Regulated Entity use assets that it does not own to provide Regulated Distribution Services, Regulated Retail Services or Distribution Connection Services. Such assets could be operated under lease arrangements, hiring or rental arrangements, or other forms of contractual use-of-asset agreements.

On a legal point of view, it is true that for an asset to be considered in the RAB, the following should be established: 1) existence; 2) use and usefulness in the electric operation; and 3) legal ownership. However, provided these assets not owned by the Regulated Entity are used to provide Regulated Distribution Services to its customers then it may be reasonable to include a reasonable cost for such asset either as part of its RAB or operating expenditure. The Regulated Entity would only be allowed to recover it as part of its RAB if the replacement cost of the leased asset including an allowable return is lower than the cost of the lease, rent, hire-purchase or other contractual arrangements. However, if the cost of the lease, rent, hire-purchase or other contractual arrangements is lower than the replacement cost of the leased asset including an allowable return then only the cost of the lease may be recovered as part of the operating expenditure.

Upgrades, renewals or refurbishments carried out on assets not owned by a Regulated Entity should normally be for the account of the asset owner. However, in some cases a Regulated Entity may be obliged to carry out such works at its own expense on assets that it does not own, for which the costs would under normal circumstances have been capitalized against the asset. Such situations should be brought to the attention of the ERC and will be considered on a case-by-case basis, taking into account the use-of-asset arrangements, the duration of the arrangements and the terms and date on which assets will revert back to the owner. If approved by the Commission, the costs associated with such upgrades, renewals or refurbishment could be capitalized (as per Section 5.2.2) against the asset or alternatively, an associated (book) asset could be added to the Regulatory Asset Base reflecting just the additional components, and depreciated over the standard lives of the main asset in question, or the remaining term for which the asset will be operated by the Regulated Entity.

5.1.18 Data requirements

The data requirements for asset valuation will be set out in the Valuation Handbook.

5.2 Capital expenditure forecasts

Clause 4.12 of the RDWR discusses the basis of the capital expenditure forecasts that must be provided to the ERC by Regulated Entities. Forecasts have to be provided for each Regulatory Year of the Third Regulatory Period.

In addition, the capital expenditure budget for Regulatory Year 2011 should also be separately provided.[33]

Where capital expenditure projects are forecast to extend across Regulatory Years, the expenditure should generally be recognized only in the Regulatory Year in which the assets are planned to be commissioned. An exception to this may be made where new assets will be partly commissioned during the course of construction – forecast expenditure on those assets that will be commissioned in an earlier Regulatory Year may be reflected in that earlier year.[34]

Following the approval of a Regulated Entity's capital expenditure forecasts by the ERC, these are to be included in the building block analysis through which the annual revenue requirement of the Regulated Entity will be determined.

5.2.1 Definition of capital expenditure

For purposes of the RDWR and this Position Paper, capital expenditure is defined to be those expenses incurred by a Regulated Entity on property (excluding intellectual property), plant or equipment to :

- augment the capacity of the network to meet demand growth or new customer requirements;
- replace aging and obsolete assets;

[33] This CAPEX budget may be similar to that approved by the ERC for RY2011 in its final determination for the Second Regulatory Period, but could differ if Regulated Entities have adapted their CAPEX spend profiles. See also section 12.2.2.

[34] An example would be a major substation project which could be staged and which may be partly energized and used before the final completion date.

- extend the useful lives of network assets to beyond the standard regulatory lives;
- improve the quality, efficiency and reliability of supply and delivery of electric service;
- make capital improvements that are necessary for meeting the established service quality targets and/or technical and safety obligations imposed by regulatory or statutory agencies;
- purchase or construct Non-network Assets (for example, buildings and vehicles) required for the normal efficient operation of the Regulated Distribution System[35]; and
- relocate assets needed to implement road widening projects or other third party initiated projects.

An item of property, plant and equipment should be recognized as an asset when:

- it is probable that future economic benefits associated with the asset will flow to the Regulated Entity (which could include the avoidance of economic harm which may otherwise occur); and
- the cost of the asset to the Regulated Entity can be measured reliably.

5.2.2 *Cost estimates for capital expenditure*

Unless extraordinary conditions can be demonstrated that would cause a material difference in the establishment cost of an asset, capital expenditure forecasts should be based on the standard replacement costs schedules contained in the Valuation Handbook. These standard costs may be adapted as appropriate through application of the multipliers provided to account for differences between distribution networks.

To allow a reasonable assessment of their forecast capital expenditure, Regulated Entities must provide evidence of how their cost estimates were derived. For major projects, this should include a detailed breakdown of the assets on which project cost estimates are based and the quantities of these assets included in the estimates.

Where asset investments are planned for items not included in the standard replacement schedules, this must be indicated and the basis on which the cost estimates for these were prepared should be described. For major projects, this should again include a detailed breakdown of the assets on which project cost estimates are based and the quantities of these assets included in the estimates.

5.2.3 *Capitalization of operating or maintenance expenses*

In the standard replacement cost schedules in the Valuation Handbook, allowance is made for operating costs associated with the creation of an asset that can be capitalized. No further allowance for capitalizing costs associated with such standard assets will therefore be allowed. However, in the case of assets not described in the replacement cost schedules,

[35] While this definition refers specifically to Distribution System assets, the principle would also apply to Distribution Connection Assets and Regulated Retail Services assets.

or in special cases, it may be necessary to capitalize operating or maintenance expenses incurred by Regulated Entities in relation to a specific asset.

The International Accounting Standards (IAS) adopted in the Philippines will apply with regard to the capitalization of such operating and maintenance expenses by Regulated Entities. In general, only those operating expenses incurred directly in the course of establishing capital assets can be capitalized to become part of the value of the associated assets and therefore to be included in the capital expenditure forecasts.

Cost components that can be capitalized are :

- purchase price, including import duties and non-refundable purchase taxes, and any directly attributable costs of bringing the asset to working condition for its intended use, e.g., cost of site preparation, initial delivery and handling costs, installation costs, professional fees such as for architects, engineers and project managers, and estimated cost of dismantling and removing the asset and restoring the site, and the estimated costs of dismantling and removing the asset as a provision under IAS 37, Provisions, Contingent Liabilities and Contingent Assets;
- borrowing costs allowed under IAS 23, to the extent that these are not already recovered through the CWIP factor;
- administration and other general overhead costs and start-up and similar pre-production costs which are directly attributed to the acquisition of the property, plant and equipment and/or bringing the asset to its working condition; and
- major spare parts and stand-by equipment qualifying as property, plant and equipment.[36]

For subsequent expenditures on assets, capitalization shall be done only when it is probable that future economic benefits, in excess of the originally assessed standard of performance of the existing asset, will flow to the enterprise. As such, the expenditure improves the condition of the asset beyond its originally assessed standard of performance, as follows:

- modification of an asset to extend its useful life, or increase its capacity;
- upgrade of assets to achieve a substantial improvement in the quality of output; and
- adoption of new production processes enabling a substantial reduction in previously assessed operating costs.

The following items are to be excluded from capitalized costs:

- any trade discounts and rebates given in relation to the asset;
- initial operating losses incurred prior to an asset achieving planned performance;
- applicable government grants in accordance with IAS 20 (Accounting for Government Grants and Disclosure of Government Assistance); and

[36] These apply when the Regulated Entity expects to use them during more than one period. If the spare parts or servicing equipment can be used only in connection with an item of property, plant and equipment and their use is expected to be irregular, they are accounted for as property, plant and equipment and are depreciated over a time period not exceeding the useful life of the related asset.

- expenditure on repairs or maintenance of property, plant and equipment made to restore or maintain the future economic benefits that an enterprise can expect from the originally assessed standard of performance of the asset. For example, the cost of servicing or overhauling plant and equipment is usually a maintenance expense since it restores, rather than increases, the originally assessed standard of performance.

Regulated Entities have to provide the ERC with a description of their general approach to capitalization of expenses. Any administrative, management, governance or other overhead costs to be capitalized must be separately identified to the ERC in the capital expenditure forecasts, together with the justification for this decision and the manner in which the costs involved are calculated. The Regulatory Reset Expert will consider these costs and advise the ERC on the reasonableness thereof. After consideration, the ERC may decide to accept these costs as part of the capital expenditure forecasts, or may decide to reclassify them as operating and maintenance costs (if deemed efficient and reasonable).

Regulated Entities should take particular care in their forecasting to prevent capitalizing costs that have already been accounted for in the operating and maintenance expenditure forecasts (or vice versa).[37]

5.2.4 Categorization of capital expenditure forecasts

Regulated Entities have to provide their forecast capital expenditure broken down into the asset categories described in Clause 4.8.5 of the RDWR and as discussed in Section 5.1.4 above for the Regulatory Asset Base. The breakdown of capital expenditure should include all capital expenditure projects planned for each Regulatory Year, including those major projects discussed in Section 5.2.5 below.

In addition, capital expenditure forecasts related to Regulated Distribution System assets must be divided into further subcategories, for load growth, asset renewal and asset refurbishment. To avoid confusion over what constitutes growth, renewal or refurbishment projects, the following should be noted:

- Renewal projects are those that replace existing assets due to their deteriorating condition, when the anticipated economic cost of operating, refurbishing and maintaining these assets exceed that to renew them.
- Renewal projects can also be to replace assets due to technological obsolescence.
- There is often a significant degree of overlap between maintenance and refurbishment projects. In general, maintenance works are defined as those works required to ensure that an asset performs its designated function for its full standard asset life. Refurbishment projects on the other hand, are those that are used to increase the serviceability of assets to beyond their normal standard asset lives. Expenses incurred for maintenance activities should not be capitalized.

[37] The same also applies for the reporting of historical costs.

- Refurbishment projects often involve at least a degree of asset replacement, which may give rise to some ambiguity. Such projects should be classed in accordance with their underlying activities that constitute the largest part of the project value.
- Projects undertaken to renew assets because they can no longer meet growing demands should be classed as growth projects.

5.2.5 Major capital expenditure projects

The capital expenditure program must separately identify each major capital expenditure project planned for each Regulatory Year during the Second Regulatory Period. In terms of Clause 4.12.1 of the RDWR, major projects are defined as those for which expenditure will exceed the lesser of 20% of the total capital expenditure forecast for a Regulatory Year, or PhP30 million.

For each major capital project separately identified, the following additional information must be provided:

- a description of the project, including the reason why it is required and what its intended outcome is;
- the estimated cost of the project, broken down by major construction line items and indicating the type and quantity of assets included in the estimate;
- the planned construction period and dates, from the date when significant costs will start to be incurred through to the commissioning date of the project;
- the estimated cost to be incurred against the project in each Regulatory Year, or after the Third Regulatory Period;
- the justification for the ranking of the project relative to others in terms of its timing;
- the anticipated implication if the project is to be deferred or cancelled;
- the anticipated impact of the project on the performance measures of the Regulated Distribution System;
- the classification of the project into the categories and classes described in Section 5.2.4 above;[38] and
- the operating cost that will be capitalized against the project, including overheads.

As noted in Section 5.2.2, project cost estimates should as far as practical be based on the asset types and replacement costs contained in the standard asset replacement schedules in the Valuation Handbook.

The information provided for each major project must be sufficient to allow the ERC to make a well-informed decision on the appropriateness of the project for inclusion in a capital expenditure program and whether the cost for a project has been reasonably estimated. If sufficient supporting evidence is not provided, the ERC is likely to exclude such projects from the approved capital expenditure for the Third Regulatory Period.

[38] If a project is deemed to cover more than one category, it must be included in that category in which the bulk of expenditure would fall.

Templates for major capital project forecasts will be provided by the ERC for use in the Regulated Entities' Revenue Applications.

5.2.6 *Justification of other capital expenditure*

The residual capital expenditure for each Regulatory Year, after removing the major projects discussed in Section 5.2.5 above, has to be justified against each asset category. Regulated Entities have to provide sufficient evidence and justification why the expenditure is required and is considered to be of reasonable magnitude. If sufficient supporting evidence is not provided, the ERC is likely to limit the extent to which such minor projects will be approved for the Third Regulatory Period.

Templates for minor capital project forecasts will be provided by the ERC for use in the Regulated Entities' Revenue Applications.

5.2.7 *Historical evidence of capital expenditure*

As part of their Revenue Applications during the Regulatory Reset Period, Regulated Entities have to provide historical records of capital expenditure on Distribution System assets, Non-network Assets, Distribution Connection Assets and Regulated Retail Services assets for the last four Regulatory Years up to the year ending on June 30, 2010.

These expenditure records have to be broken down as closely as reasonably possible to the categories described in Section 5.1.4 above.

Projects completed over this period with values exceeding PhP30 million or 20% of the total annual capital expenditure should also be separately identified.

5.2.8 *Isolation of CPI and foreign exchange impacts*

Capital expenditure forecasts used in calculating the annual revenue requirement should be provided in nominal terms. However, for the purposes of analyzing expenditure forecasts and trends, these forecasts should also be provided in real terms. Supporting information must be provided by Regulated Entities on the assumptions made and information used with regard to forecasting the CPI (Philippines and the USA) and the PhP/US$ exchange for the Third Regulatory Period.

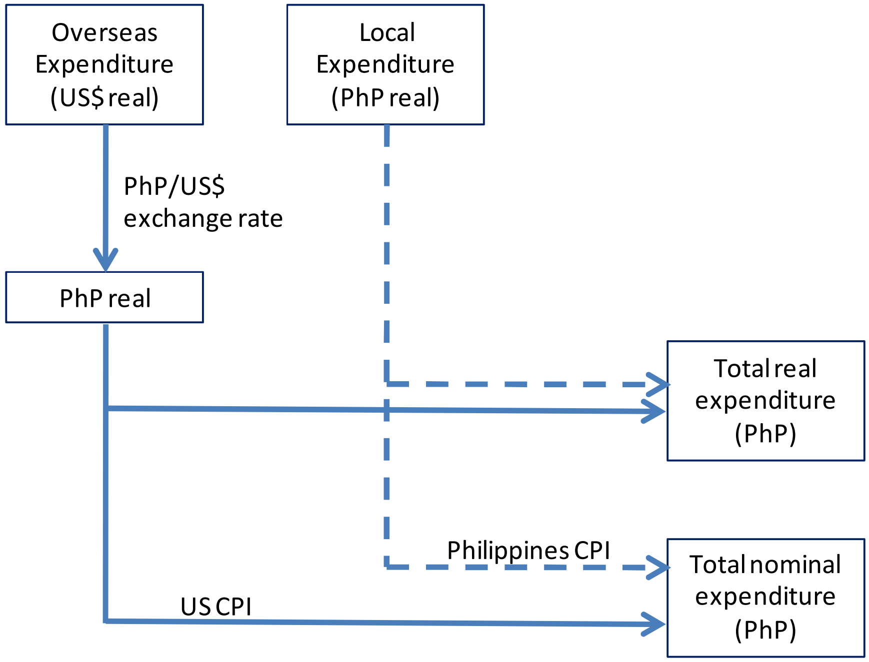
To be consistent, the CPI and exchange rate forecasts used by Regulated Entities for forecasting operating and maintenance expenditure (described in Section 4.1.5) and that used for capital expenditure forecasts have to be the same.

The form of conversion of forecast real capital expenditure will be similar to that described for operating and maintenance expenses in Section 4.1.5. For the purposes of this calculation, all expenses to be incurred in other foreign currencies have to be converted to a US dollar equivalent.

The conversion of capital expenditure to a nominal PhP value is indicated in Figure 5.5.

Historical expenditure figures should be provided in actual (nominal) terms for the year in which it was incurred.

Figure 5.5: Preparation of Nominal PhP Capex Forecast



5.2.9 *Evaluation of capital expenditure forecasts*

A review team will be created by the ERC to review the capital expenditure forecasts and supporting documentation submitted by each Regulated Entity. This team will be made up of internal ERC staff and one or more Regulatory Reset Experts retained in terms of Article XIV of the RDWR. The review team will consider whether these forecasts :

a) fairly represent the capital expenditure program such that all related capital expenditure is grouped into single projects;

b) are based on the best available prices obtainable from the international market;

c) conform with the trending patterns established from assessing the historical expenditure records;

d) are reasonably efficient from a design and implementation point of view;

e) are reasonably sufficient to support the forecast growth of connections, energy delivered or co-incident peak demand;

f) are reasonably sufficient to allow the Regulated Entity to maintain or improve performance target levels as specified by the ERC;

g) are required to meet regulatory and/or statutory requirements; and

h) make reasonable allowance for forecast changes in CPI or exchange rate levels.

In judging whether the forecast expenditure is efficient, the review team will apply the optimization principles described in the Valuation Handbook, as also described in Section 5.1.10 above.

Based on the expenditure review, the review team will prepare a schedule of those major capital projects that it deems necessary for the continued efficient operation of each

Regulated Entity, ranked in order of importance. In addition, an indication of the recommended expenditure allowance on smaller capital projects will be prepared.

Following consideration of the advice from the review team, the ERC will approve the Regulated Entities' proposed capital expenditure forecasts if the factors on which they are based meet these evaluation criteria. Otherwise, the ERC will consult further with that entity and approve such forecasts as it considers necessary for the criteria to be met.

The RDWR does not explicitly allow for the use of international benchmarking to establish the efficiency of capital expenditure. While it is recognized that benchmarking of capital expenditure is more problematic than for operating and maintenance expenditure and even more subject to distortion by local environmental, network and societal factors, the ERC considers that there may still be value in providing comparisons with international benchmarks, if these are readily available to a Regulated Entity.

The ERC will rely on a number of sources of evidence to determine the efficiency of capital expenditure and appropriate benchmarking results may enhance this process, which may include reviewing evidence from other privately owned Philippines Distribution Utilities.

5.2.10 Impact of capital expenditure on service levels

The ERC is keen on understanding the impact of capital expenditure on the service performance of Regulated Entities or the performance of Distribution Systems. Regulated Entities should therefore indicate whether their capital expenditure forecasts provide for maintaining current performance levels, or whether they include some provision for improved performance levels.

5.2.11 Data requirements

Data templates for the capital expenditure forecasts to be provided by Regulated Entities as part of their Revenue Applications will be supplied by the ERC at the Pre-filing conference. These templates will allow for expenditure forecasts to be broken down into the asset categories and expenditure types discussed above.

5.3 Weighted Average Cost of Capital

The allowed rate of return to apply to the Regulatory Asset Base (and working capital) is a key factor to be determined for the Regulatory Reset. This return will be based on the weighted average cost of capital (WACC) for Regulated Entities. The WACC will be determined such that it will encourage investment in electricity distribution assets, providing reasonable, but not excessive returns to investors.

While the methodology for calculating the WACC is relatively straightforward, determining the appropriate values for the underlying parameters listed below requires a significant degree of attention. The ERC recognizes that determining these parameters is subject to observation of results that can vary considerably over time, as well as to interpretations and assumptions that often differ markedly between various informed parties. As such, it recognizes that a substantial degree of uncertainty exists on what constitutes the correct point estimate of the WACC. It therefore intends to adopt a range for the WACC, identifying the final applicable value from within this range.

Given the developing nature of the regulatory environment, especially performance-based regulation, in the Philippines and the fact that many of the regulatory decisions may still be subject to challenges and delays while the processes are embedded, Regulated Entities face an unusual degree of regulatory uncertainty. This affects the risk profile of these Regulated Entities and the commensurate rate of return to investors in electricity distribution infrastructure. To compensate for this uncertainty, the ERC will select the WACC from the 75th percentile of the suggested range of values (rather than using the average from the range).

In selecting this point value, the ERC also takes into account the asymmetric impact on the dynamic efficiency of utilities of setting this parameter too low. Essentially, if the WACC is set too low, this discourages investment in distribution network assets. Such underinvestment will provide a small upside gain to consumers in the short term, due to lower distribution prices, but will eventually lead to insufficient network infrastructure which will inhibit growth, seriously compromise supply quality and discourage investment of other industries that depend on a reliable source of electricity. The wider impact on the economy is therefore potentially very substantial. On the other hand, by setting the WACC somewhat too high, this will have some negative impact on consumers arising from higher prices. However, the overall economic impact of this would be much smaller than from setting the value too low.

5.3.1 Overview of methodology

The methodology for calculating the WACC is described in Clause 4.11 of the RDWR. It is based on the classical approach to the WACC, which the ERC believes provides the best balance between the building blocks underlying the calculation of the annual allowed revenue for Regulated Entities.

It is important to note that the WACC calculated in terms of the RDWR is a regulatory figure, applying to Regulated Distribution Systems only. It is not necessarily the same as the WACC that would be calculated for the wider business or for the purposes of valuing these businesses. In addition, it is unlikely to correspond closely to the WACC that may be observed from studying the returns on equity for a publicly listed entity.

The formula proposed for the Regulatory WACC is :

$$WACC = r_e(\frac{E}{V}) + r_d(\frac{D}{V})$$

where,

$$r_e = r_f + \beta_e(r_m - r_f)$$

$$r_d = r_f + DM$$

and,

r_e = the cost of equity

r_d = the cost of debt

E	=	the proportion of equity funding assumed for regulatory purposes in the capital structure of a Regulated Entity
D	=	the proportion of debt funding assumed for regulatory purposes in the capital structure of a Regulated Entity
V	=	E + D
r_f	=	the risk-free rate within the Philippines
$r_m - r_f$	=	the market risk premium
β_e	=	the industry average equity beta for electricity distribution businesses in the Philippines
DM	=	debt margin (or premium)

Examples of how the WACC was calculated for the first two entry groups can be found in the final determinations on the price control arrangements for each of the utilities in these groups - this is available on the ERC website[39] or copies can be requested from the ERC. The discussion below focuses on the methodology only, and the detailed calculations are not repeated.

5.3.2 Locked parameters

In the RDWR, the ERC has set a number of the variables used for the calculation of the WACC at levels which present reasonable estimates of average good financial practices for financially viable companies in the Philippines. This was done to address the difficulty in undertaking a statistically meaningful analysis of these values in the Philippines, given the relative immaturity, the small size and the potential lower liquidity of the publicly traded local market.

For the Second Regulatory Period, the following values have been locked in :

a) Market risk premium is set to 0.06 (6% p.a.)[40]

b) 60% Funding by equity and 40% funding by debt is deemed reasonable, resulting in a debt/equity ($\frac{D}{E}$) ratio of 0.67.

5.3.3 Risk Free Rate in the Philippines

There are a number of ways a risk free rate can be estimated for the Philippines. The two prime ways for purposes of calculating the WACC are as follows:

- through a direct measure using the yields on long dated Philippines Treasury bonds denominated in peso; or

[39] www.erc.gov.ph

[40] The ERC appreciates that this figure could be the subject of much debate, especially if it is to be used to reflect the country risk associated with investments in the Philippines. However it decided to set the market risk premium at an appropriate value for developed markets and rather reflect the country risk in the risk free rate.

- an indirect measure using yields on long dated USA Treasury bonds denominated in US$ and adjusting these for the inflation differential and the country risk.

The ERC has used both methods to obtain the most reasonable estimate of the risk free rate for the Philippines. The outcome of each method is discussed in turn.

i. Direct Measure

There are two ways of obtaining a direct estimate of the risk free rate in the Philippines to be applied to peso cash flows. These are by looking at the yield curve to find an observed asymptote for long dated Treasury bonds and by looking at the average of the yields over a reasonable number of trading days for Treasury bonds of a particular tenor (usually long dated tenors). These ERC will apply both methods to derive an appropriate estimate of the risk free rate.

ii. Indirect Measure

The indirect measure of the risk free rate can be estimated using the following formula.

$r_f = [(1 + r_{f\,USA}) / (1 + i_{CPI\,USA})] \times (1 + i_{CPI}) \times (1 + CRP) - 1$

where:

r_f = risk free rate estimated for the Philippines using an indirect method.

$r_{f\,USA}$ = risk free rate estimated in the USA using a direct method.

$i_{CPI\,USA}$ = inflation rate estimated for the USA.

i_{CPI} = inflation rate estimated for the Philippines.

CRP = country risk premium expected by investors for investing in the Philippines, which does not include any adjustment for exchange rate risk.

The manner in which these inputs will be derived are discussed in the following paragraphs.

(a) USA Risk Free Rate

The ERC will source the yields of US$ Treasury Bonds, using different tenor periods (5, 10 and 20 years). These will be analyzed to obtain an indication of the most appropriate reference for the risk-free rate.

(b) USA Inflation Rate

The ERC will source the USA CPI data from the Bureau of Labor Statistics in the USA. It will use the 12-month average of the daily rates as basis for this parameter.

(c) Philippines Inflation Rate

The ERC will source the Philippines CPI data from the National Statistical Office (NSO) in the Philippines. It will use the 12-month average of the daily rates as basis for this parameter.

(d) Country Risk Premium

There are a number of sources for data on the country risk premium (CRP).

(1) Yield Curve Difference

The ERC will source Philippine Treasury and corporate bond data for US$ denominated bonds which are traded in the Philippines. These yields can be compared to the USA Treasury bond data for US$ denominated bonds traded in the USA. The difference in the yields between these two sets of yield data can be used to infer an estimate of the country risk. This is the premium expected by current investors for investing in the Philippines as opposed to investing in the USA. This CRP excludes a return to compensate for the exchange rate risk of converting peso to US$, because the bonds are both denominated in US$. The primary assumption is that the US$ denominated bonds in the Philippines have sufficient liquidity that the yields provide a measure of yield from free and open market transactions at any point in time. The secondary assumption is that the government bonds in each country have the same contractual arrangements and hence the analysis is a comparison "like-for-like" investment offers, excluding the country of investment.

(2) Average Yield Difference by Maturity

The ERC will undertake further analysis, using the available US$ bond data from three bonds with tenor of 5, 10 and 20 years, to determine the average of the yield difference at the three different time-to-maturity profiles.

(3) Independent Data Source

The ERC will seek data on the CRP measured by an independent source to the current regulatory debate. To date the UK office of PricewaterhouseCoopers (PwC) has provided this service. They use US$ bond yields and country rating statistics to derive measure of CRP on a quarterly basis.

The methodology to estimate the CRP used by PwC of the UK can be found at the web site www.costofcapital.net .

5.3.4 Return on Equity

In Section 4.11.4 of the RDWR, the ERC has accepted the use of the Capital Asset Pricing Model (CAPM) as the methodology in developing the cost of equity for Regulated Entities.

$$r_e = r_f + Beta_e \times (r_m - r_f)$$

which simplifies to :

$$r_e = r_f + Beta_e \times MRP$$

where:

r_e = the nominal cost of equity.

r_f = risk free rate estimated for the Philippines as estimated above.

$Beta_e$ = the Equity Beta for electricity distribution business as determined by the ERC for regulatory purposes in accordance with Sections 4.11.6 to 4.11.8; and

$(r_m - r_f)$ = the Market Risk Premium (MRP), which the ERC has set as 6% p.a. in the RDWR and reiterated in the TransCo Draft and Final Determinations.

These inputs are derived and discussed in turn in the following paragraphs.

i. <u>Equity Beta</u>

The equity beta to apply to Distribution Utilities must be estimated from the betas seen in overseas markets for electricity transmission and distribution companies whose prime activity is the provision of poles, wires, transformers and switching infrastructure for the delivery of electrical energy from generators to loads. This is necessary as there is only one electricity distribution company in the Philippines traded on the Philippines stock exchange (MERALCO), and this is for the vertically integrated company (not indicating the relative price movements of distribution business in isolation).

The process for estimating the equity beta requires two steps:

- de-levering the equity betas seen in overseas markets into asset betas for companies with comparable businesses to that of local Distribution Utilities, by removing the impacts of financial leverage (or gearing) and of effective taxation rates on the equity betas observed in the market place; and
- re-levering the asset beta into an equity beta for Distribution Utilities using the assumed regulatory gearing specified by the ERC (a tax adjustment to the WACC is not considered necessary for the Second Regulatory Period as this is estimated in the cash flows against which the overall WACC is applied).

These two steps are discussed in turn in the following paragraphs.

The ERC will explore various sources of data to estimate the equity beta and has in the past used direct market measures using Bloomberg data and independent research data from the publications of Prof. Anwath Damodaran on the Stern University.

The ERC notes that the asset beta values that can be observed in international markets would generally reflect developed economies, whereas the Philippines is a developing economy, with an associated higher systemic risk associated with infrastructure investment. To reflect this, the asset beta adopted for the WACC determination will be adapted to reflect the higher systemic risk faced by Philippines utility investors.

(a) Estimate of Equity Beta for Distribution Utilities - Direct Measures

The ERC will source data on various electricity companies from overseas markets. The primary information derived from such sources will include the:

- Equity beta;
- Market capitalization (a measure of equity value);
- Short and long term debt, and cash (a measure of debt value); and
- Effective tax rate (a trailing 12 month measure).

This data has to be de-levered to generate the asset betas of representative distribution and vertically integrated electricity businesses. Using the regulatory assumptions on debt and equity, an equity beta will be generated, using the CAPM formula.

(i) De-levering of Observed Equity Betas to an Estimate of Asset Beta

The RDWR specifies a de-levering formula in Section 4.11.8 as follows:

$Beta_a = Beta_e \ / \ [1 + (1 - T_e) \ x \ D_m / E_m]$ [41]

Where new terms are defined as:

T_e = the effective corporate tax rate for that business as ascertained from information provided by an independent international ratings agency or financial market reporting company or, in the absence of such data, the corporate income tax rate for the country in which the relevant business is located (in either case expressed in decimal terms);

D_m = the amount of debt funding in the capital structure of that business as ascertained from information provided by an independent international ratings agency or financial market reporting company; and

E_m= the amount of equity funding in the capital structure of that business as ascertained from information provided by an independent international ratings agency or financial market reporting company.

This formula is used to take an observed market "equity beta" for a particular stock and to de-lever it to an "asset beta". There are a number of assumptions used in this analysis, but the primary assumption is that the observed variability of a stock price in the market place is a result of 'systematic' risk arising from the operation of a business in a particular industry sector. This risk is influenced by the type of business and the 'operational' risks it must bear and 'financial' risk (or leverage risk associated with the proportion of debt used to fund the company).

The 'asset' beta is assumed to embody the 'operational' risk seen by the market for assets of a similar type relative to the average risk of the market portfolio (the so-called market line). Where the asset has a systematic risk which is equal to the average of the market portfolio, the asset beta is equal to 1.0. If it is perceived to be less risky than the market portfolio, the asset beta will be less than 1.0, if more risky it will be greater than 1.0.

The de-levering formula gets rid of the impact of the financial leverage (including the tax effect). It should be noted that there is a preference to use the 'effective' tax rate for the observed stocks, but in some instances the data on these stocks does not include the effective tax rate, or such rate is clearly distorted through one-off annual tax payments anomalies (the negative tax rates are an example of this, where accounting measures of tax payments distort the calculation). In these instances the corporate tax rate or the highest marginal corporate tax rate is used as a proxy for the effective tax rate.

[41] This formula is the Hamada levering / de-levering formula.

Once the asset beta has been decided, the estimate of the equity beta is undertaken as follows.

(ii) Re-levering of Estimate of Asset Beta to an Equity Beta

The RDWR specifies a re-levering formula in Section 4.11.7 as follows:

$Beta_e = Beta_a \times [1 + (D / E)]$ [42]

Where:

$Beta_a$ = the industry average Asset Beta determined for privately owned electricity distribution businesses in the Philippines (excluding electricity distribution business conducted by Electric Cooperatives)

D = the amount of debt funding assumed for regulatory purposes in the capital structure of the Regulated Entity, being 40% of V for the Second Regulatory Period; and

E = the amount of equity funding assumed for regulatory purposes in the capital structure of the Regulated Entity, being 60% of V for the Second Regulatory Period.

This formula is used to take an agreed "asset beta" for a particular stock (usually the average of the de-levered asset betas of other stock with the same type of fundamental assets and physical situation either within the same market or where these do not exist, in overseas markets) and to re-lever it to an "equity beta" for the particular business under consideration. The re-levering adds back the assumed effect of the financial leverage (or financial risk) which the particular business will be assumed to adopt for regulatory purposes. In the case of the RDWR, the assumed financing is 40% debt and 60% equity.

(b) Comparable Overseas Regulatory Decisions

Research of regulatory decisions for companies in overseas jurisdictions will be used to provide a comparison of asset betas and resulting equity betas for electricity distribution companies in regulatory regimes similar to that in the Philippines. (It should be noted however, that all these decisions are for developed markets in stable environments.) The beta figures thus obtained should be useful as indicators, but lower than that which would normally apply to the Philippines environment.

(c) Comparable Philippines Regulatory Decisions

The ERC believes there is reasonable comparability between its recent cost of capital decisions based on a CAPM analysis. These decisions will therefore also be taken into account in determining the equity beta.

[42] This formula is the Harris – Pringle formula which is normally used in conjunction with the 'classical' WACC formula, which is expressed as the post-tax nominal WACC. See Ogier T., Rugman J., and Spicer L., *The Real Cost of Capital* – A business field guide to better financial decisions, Prentice-Hall, 2004, Chapter 1 and page 208.

5.3.5 Market Risk Premium

The ERC has set the value of the Market Risk Premium (MRP) to be 6.0% for the Second Regulatory Period in the RDWR and reinforced this issue in the Final Determination for TransCo (NGCP) and all the privately-owned distribution utilities. This same value will be adopted for the Third Regulatory Period.

The ERC believes this is a reasonable issue because:

- there is continuing debate in academic circles and literature as to a reasonable measure to ascribe to this parameter in applying the Capital Asset Pricing Model (CAPM), and such values lie anywhere between 2.5% and 9.0% depending on the time series, market and statistical study techniques used;
- the time series data on stock market equity returns and debt market returns to develop such a measure for the Philippines does not have sufficient duration to allow a statistically meaningful measure to be undertaken;
- the data necessary on the Philippines market returns does not exist over a sufficient duration to allow meaningful statistical estimates of ‘relative volatility’ to allow MRP adjustments to the MRP for those cost of equity methodologies which require such adjustment;
- to the greatest extent possible the ERC has adopted a RDWR which has cash flow adjustments and safeguards which mitigate to a large extent many of the additional operational risks which are frequently mistaken for systematic risks and are absent in regulatory WACC analysis in the UK, New Zealand and Australia, but which might otherwise suggest a higher MRP for the Philippines investment climate.

5.3.6 Return on Equity

From the methodology described above, the ERC will estimate the regulatory return on equity for Regulated Entities. This will be a post-tax nominal measure of the return on equity, as the tax adjustments are undertaken in the regulatory cash flow analysis.

5.3.7 Return on Debt

The cost of debt (r_d), expressed in decimal terms, is calculated as follows:

$$r_d = r_f + DM$$

Where:

r_f = the risk-free rate within the Philippines, expressed in decimal terms, as determined above; and

DM = the debt margin (or premium) within the Philippines (expressed in decimal terms) as determined by the ERC, which conceptually represents the margin above the risk-free rate within the Philippines that is requested by debt providers for providing funds to the Regulated Entity to the extent such debt arrangements are representative of arms length negotiated rates in liquid markets and are financially efficient.

A. Debt Margin

The RWDR calls for a debt margin which is based on an efficient industry average rather than on the specific debt margin experienced by any particular business. This approach is part of the incentive regime which provides incentives for the Regulated Entities to better the regulatory WACC by their actual financing costs.

Feedback on the approach used in the ERC's preliminary regulatory WACC analysis suggested that a debt was harder to arrange for smaller distribution utilities and that the debt margin required by debt providers was likely to be higher than industry average in some cases. At present the debt margin which best balances the financing needs of both large and small privately owned distribution utilities is uncertain.

Thus, the ERC must estimate a debt margin assuming a level of debt which is reasonably balanced financially and which could be supported by ownership by either small or large, privately owned distribution companies. The ERC will consider feedback obtained from interested parties at public hearings, as well as examine the availability of guaranteed loans to utilities in the Philippines.

5.3.8 Weighted Average Cost of Capital

There are a number of valid ways to represent the weighted average cost of capital (WACC). These include:

- Post-tax nominal;
- Post-tax real;
- Pre-tax nominal;
- Pre-tax real; and
- Vanilla.

The RDWR prescribes a "Vanilla" form of the WACC, using the following formula:

$$WACC = [r_e \times E / V] + [r_d \times D / V]$$

Where:

r_e = the cost of equity;

r_d = the cost of debt;

E = the amount of equity funding assumed for regulatory purposes in the capital structure of the Regulated Entity, being 60% of V for the Second Regulatory Period;

D = the amount of debt funding assumed for regulatory purposes in the capital structure of the Regulated Entity, being 40% of V for the Second Regulatory Period; and

V = E + D.

5.4 Regulatory Depreciation

Regulatory depreciation is described in Clause 4.10 of the RDWR. This applies to the depreciation of both asset components making up the Rolled Forward Regulatory Asset Base – on the one hand, those assets in existence at the start of the Second Regulatory Period, and on the other, the assets coming into existence thereafter. Depreciation on these two components is calculated separately, but by using the same methodology and standard asset lives discussed below.

5.4.1 Standard regulatory lives of assets

The RDWR requires that a weighted average regulatory life must be determined for each asset category (Clause 4.10.1[a]).[43] It envisages that this should be the weighted average economic life of assets, where the economic life of an asset is deemed to expire when the costs of maintenance and repair of that asset exceed its efficient replacement cost on a project comparison basis, using a forward-looking discounted cash flow analysis.

In addition, it requires that the regulatory asset life must be the same for the same asset category for each Regulated Distribution System. For the Third Regulatory Period, the ERC will be developing a Valuation Handbook (as described in Section 5.1.1). As part of the development of this handbook, the standard asset lives will be re-evaluated. These standard lives will form part of the asset replacement schedules included in the handbook and will be used for the depreciation of assets for all Regulated Entities during the Third Regulatory Period.

It is recognized that some Regulated Entities may own assets that do not fit into the categories provided, or may have compelling evidence that demonstrates that the standard lives should be adapted. Any such evidence will be considered by the Regulatory Reset Expert appointed for the First Entry Point to review the Re-valuation Report. It is also recognized that the lifespan of assets within an asset category may vary and that figures in the Valuation Handbook will therefore be the weighted average lifespan of a category.

The standard lives will be used not only to depreciate the existing asset base as of the start of the Third Regulatory Period, but also for assets acquired thereafter.

5.4.2 Determining the age of assets for the purpose of the Re-valuation

For the Re-valuation Report, the Regulated Entity must form an opinion on the weighted average age of the assets in each asset category at the time of the Re-valuation. It is anticipated that this determination will be based largely on the valuation registers prepared for the Initial Re-valuation for the Second Regulatory Period, as updated by the Regulated Entities during the Second Regulatory Period. However, further sampling and auditing of asset information will be required from the Regulated Entities' independent valuation consultants and/or auditors, and will also be conducted by the ERC's Regulatory Reset Expert reviewing the Re-valuation Reports. This is to provide the ERC with sufficient comfort that the information on which the valuations are based is sufficiently robust.

[43] The asset categories are as described in Section 5.1.4.

In cases asset age data does not exist, an assessment has to be made of the condition of the asset(s) in question and an estimate of the age based on that assessment, also taking into account the environment in which the asset is situated.

The remaining weighted average life of an asset category is calculated by deducting the weighted average age of the category from its weighted average regulatory life.

5.4.3 Proposed form of depreciation

Regulatory depreciation will be calculated on a straight line basis across the standard lifespan of assets, per asset category.

In Clause 4.10.1 of the RDWR, two methods are proposed to calculate depreciation which, if the determination of the ODRC of the Regulatory Asset Base during the Initial Re-valuation was done correctly, should provide identical results. Annual depreciation is calculated as:

- the ORC value of the asset category divided by the regulatory lifespan of the asset category; or
- the ODRC value of the asset category divided by the remaining life of the asset category.

5.4.4 Disposal of assets

The depreciation calculation in the RDWR includes a provision for the disposal of assets. This provision is calculated as the difference between the rolled-forward depreciated value of assets to be disposed of, and the forecast net income that would be derived from disposing of these assets (after accounting for any costs associated with the disposal).

For this calculation, it is therefore necessary to forecast not only the rolled forward value of the assets that will be disposed of during each regulatory year, but also the income that is expected to be earned from their disposal. The templates for these forecasts are identical to those used for capital expenditure (Appendix E).

5.4.5 Use of assets beyond their regulatory lifespan

In many cases, individual assets may have actual serviceable lives exceeding their regulatory lives. It would be economically inefficient to replace such assets merely because they reach the end of their regulatory lifespan, and would be counter to the spirit of PBR as embodied in the RDWR.

However, if such assets have no remaining value in the Regulatory Asset Base, the incentive may arise for Regulated Entities to replace them, and the Regulated Entity could legitimately include such replacements in its capital forecasts. This would be especially attractive if such assets can be disposed of for a value higher than the cost of dismantling and selling them. As the regulatory values of such assets will be zero, such disposals will not feature in the calculation of the Rolled Forward Depreciated Regulatory Asset Base and any revenue earned will be unregulated and therefore not captured under the RDWR.

The RDWR envisages that the scrutiny of capital expenditure forecasts by the Regulatory Reset Expert should avoid such potential inefficiencies.

As a further incentive to extend the economic use of assets as long as possible, assets used beyond their standard regulatory life-span will retain a book-value (for the purposes of calculating the value of the Regulatory Asset Base) of not less than 5% of the ORC of the asset.

Assets should be depreciated (using the standard asset lives discussed in Section 5.4.1) until they have a zero value in the Regulated Entity's fixed asset register. In the following year, if the asset remains in use, it should be allocated the residual 5% value (of its ORC value) for purposes of determining the rolled forward Regulatory Asset Base. This incremental increase is for regulatory purposes only and need not be reflected in a Regulated Entity's statutory accounts.

The value of assets used beyond their standard lives should be recorded in a separate asset register. This value is taken into account in the determination of the value of the rolled-forward Regulatory Asset Base, as described in Clause 4.9.1 of the RDWR.

Once an asset is finally removed from service, the 5% residual value allocated to it should be deducted from the separate register. This removal of the residual value is not considered as disposal value and should not be included in the calculation of the disposal value of assets. This is because the asset would have been fully depreciated at that stage.

6. ENERGY CONSUMPTION FORECASTS

The energy consumption forecasts form an important component of the information to be provided for the Regulatory Reset Period. These forecasts impact not only on the price setting, including the calculation of the X-factor and the maximum average price caps for a Regulated Entity, but are also key evidence to support the future operating, maintenance and capital expenditure forecasts. In addition, the settings of the individual tariff rates are influenced by the anticipated consumption of each user group.

The RDWR describes the minimum information requirements for consumption forecasts to be submitted to the ERC. However, it will be to the advantage of Regulated Entities to submit more detailed breakdowns, especially in support of particular projects or programs that they wish to embark on.

6.1 Disaggregation of forecasts

In terms of Clause 4.22 of the RDWR, each Regulated Entity is to provide the ERC with forecasts of energy (in kWh) to be delivered for each year of the Third Regulatory Period through each Regulated Distribution System it operates. The volume of such delivery will be determined by the amount of energy delivered to Connection Points, not the amount of energy entering the Regulated Distribution System. All line losses are therefore to be excluded from the forecasts.

In addition, Regulated Entities are required to provide the actual consumption figures for each of the four regulatory years up to June 30, 2010, and an updated forecast[44] for the expected consumption for the last Regulatory Year of the Second Regulatory Period (July 1, 2010 to June 30, 2011).

In Clauses 4.22.1, 4.22.2 and 6.3 of the RDWR, the forecast energy data requirements are spelled out. In terms of this, Regulated Entities have to provide energy consumption forecasts (in kWh) for each Customer Segment. (The same breakdown should be applied to the historical consumption figures.)

6.1.1 Demand forecasting

In addition to energy consumption forecasts, Regulated Entities are required to provide demand forecasts for each Regulatory Year during the Third Regulatory Period as well as for regulatory year 2011[45], measured in kW or MW as appropriate.[46] Actual maximum demand figures are also required for each of the four Regulatory Years up to June 30, 2010.

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[44] While a forecast for energy consumption and demand for this RY 2011 has been approved by the ERC in 2007 as part of its final determination on the price control arrangements for the Second Regulatory Period, it is likely that the actual consumption and demand figures will differ from the original estimates. Regulated Entities are therefore to use the best estimates based on most recent consumption trends.

[45] Ibid

[46] Where demand is measured in apparent power terms (kVA or MVA), an appropriate conversion should be made to real power (kW or MW) using historical evidence of the power factor experienced during peak times.

These figures are to be broken down, as far as practicable, into the following level of detail for each Regulated Distribution System:

- co-incident maximum demand for the Regulated Distribution System, as measured at all Grid Connection Points and connection points to generators, including embedded generation;
- maximum demand at each Grid Connection Point and connection points to generators, including embedded generation;
- maximum demand at each substation forming part of a Regulated Distribution System;
- maximum demand on each sub-transmission feeder (or combination of feeders where redundancy is built into the system); and
- maximum demand on each major distribution feeder (or combination of feeders where redundancy is built into the system).[47]

The maximum demand at any point on a network is defined as the highest peak demand experienced there (or forecast to be experienced) during any half-hour period (or other period as approved by the ERC, as long as these do not exceed an hour) during a Regulatory Year. Half-hourly demand will be determined by integrating (numerically or otherwise) the instantaneous demand experienced at that point for the half-hourly period. Such measurement is required for each half-hour period of the Regulatory Year.

Co-incident maximum demand means the combined maximum demand experienced during the same half-hour measurement period for the various points for which the co-incident demand is measured. It is not the sum of the yearly maximum demand at those points.

The ERC notes that in some cases the required metering information noted above cannot currently be provided by Regulated Entities. It therefore requires Regulated Entities to advise where this is the case. In addition Regulated Entities are to assess their metering installations and consider how, during the Third Regulatory Period, it can extend these to provide the information required. The required capital and operating & maintenance expenditure to achieve this should be included with the rest of the forecasts of the Regulated Entity at the time of the reset for the second and further regulatory periods. This expenditure will be considered by the ERC and approved if deemed efficient and appropriate for the purposes required.

The RDWR determines a maximum average price per kWh that can be charged by Regulated Entities during each regulatory year. There is a need to fairly convert a single price per energy unit (kWh) to various tariff schemes where some involve maximum demand components and others do not. To make this conversion more accurate, it is necessary to have information of both the energy consumption and the maximum demand per Customer Segment. As part of the Revenue Application, the ERC therefore requires information on the estimated co-incident maximum demand per Customer Segment as well.

[47] As before, major distribution feeders are defined as those distribution voltage level feeders that convey electricity, but not directly to consumers, or to distribution transformers from which low voltage networks are fed.

It is appreciated that the accurate measurement of (co-incident) maximum demand per Customer Segment is not practical, especially since customers from various Customer Segments are usually fed from single substations or major distribution feeders. Regulated Entities can estimate the demand per Customer Segment by allocating the demand at substations or on distribution feeders to specific Customer Segments based on the majority segment fed from that point.

An alternative approach, if the load factor of various Customer Segments is known, would be to estimate maximum demand by converting unit consumption using these load factors.

6.2 Basis of forecasting

Regulated Entities must explain the basis of their consumption and demand forecasting models in sufficient detail to allow the Regulatory Reset Expert to make an informed judgment as to the sufficiency thereof. In addition, an indication should be provided of how accurate forecasts using these methodologies have been in the past.

In making the estimates, Regulated Entities should take into account at least the following factors and their impact on consumption:

- historical growth and trends;
- economic growth data and forecasts;
- demographic patterns;
- significant macro- or micro-economic factors;
- local town-planning or development guidelines;
- industry or technological developments impacting on the use of electricity;
- residential, commercial or industrial developments of which advance notice has been received; and
- discussions with developers and major existing clients about their intended further developments.

If, after considering the inputs of the Regulatory Reset Expert(s), in the opinion of the ERC the consumption or demand forecasting for any Regulated Entity is not reasonable, the ERC will determine the forecasts for that Regulated Entity. These adapted forecasts will then be used for all the applications noted in the RDWR that rely on such forecasts, including the assessment of operating, maintenance and capital expenditure.

6.3 Data requirements

Templates for the submission of consumption and demand figures will be provided by the ERC at the Pre-filing conference for the Revenue Application.

7. CORPORATE INCOME TAX

The RDWR allows for the recovery of the anticipated annual corporate income tax payable by Regulated Entities as one of the building blocks on which the annual revenue requirement forecast will be based. However, a unanimous request was received from all Regulated Entities following consultation in 2008 on the changes to the RDWR, that the corporate income tax building block should be set at zero for the Second Regulatory Period. This was based on a recognition by the Regulated Entities that a more gradual introduction of the fully-fledged PBR regime may be appropriate, and also to minimize possible price shocks against which the ERC would intervene in any case. The ERC has decided to accept this request.

The ERC intends to continue with this approach for the Third Regulatory Period. The ERC remains of the view that recovery of corporate income tax is based on sound economic principles and will therefore retain the building block, even if the value is set at zero for the Third Regulatory period. At this stage it is intended to re-introduce this building block at actual value for the Fourth Regulatory Period, unless compelling reasons to the contrary are presented.

8. PRICE CONTROL

The setting of the average annual price caps in terms of the RDWR can be viewed in two distinct phases.

During the Regulatory Reset Period, the forecast price path will be determined, based on historical electricity distribution rates and the expenditure forecasts provided by Regulated Entities as approved by the ERC to be included in their allowed annual revenue. This leads to the Smoothed Maximum Annual Price cap (SMAP) as determined in accordance with Clause 4.15.4 of the RDWR. For the first Regulatory Year (RY2012) of the Third Regulatory Period, the Maximum Average Price cap (MAP_{2012}) will be set at the $SMAP_{2012}$ thus calculated, after being adapted for under- or over-recoveries as described below, and the performance incentive scheme bonus or penalty.

However, after the first year of the Third Regulatory Period, the actual MAP that will apply during the rest of the regulatory period will (except in highly unusual circumstances) not be the same as the SMAP. These prices will be determined on an annual basis, taking into account the actual CPI and the financial and service performance of a Regulated Entity during the previous Regulatory Year.

The initial and subsequent price setting processes are described in this Section.

8.1 Determining the forecast price path

The determination of the Smoothed Maximum Average Price cap is described in Clause 4.15 of the RDWR. In summary, it relies on the following steps:

- Determine the annual revenue requirement for each year of the Third Regulatory Period, as per the building block approach described in Clause 4.6 of the RDWR;
- Convert this allowed revenue to the present value at the start of the Third Regulatory Period;
- Determine the opening price for the Third Regulatory Period;
- Based on the forecast energy consumption and inflation rates, and the P_0 factor, determine the smoothing factor (X-factor); and
- Determine the SMAP caps for the Third Regulatory Period based on the opening price, the forecast inflation and the X-factor.

8.1.1 Dealing with under- or over-recoveries carried over from the Second Regulatory Period

The RDWR (Clause 4.3) makes provision for the correction of under- or over-recovery against the annual revenue requirement of a Regulated Entity during the previous Regulatory Year. This correction extends to the transition between Regulatory Periods.

Normal under- or over-recovery that occurred during earlier regulatory years will therefore be added to or removed from the $SMAP_{2012}$ to derive the MAP_{2012} on which the actual distribution rates for RY2012 would be based (as described in Section 8.2.5).

However, instances have arisen during the Second Regulatory Period where under-recoveries have become so large that these could not be fully corrected for without breaching the side constraints set to avoid excessive annual distribution price variations (Clause 6.4 of the RDWR). Depending on the magnitude of under-recovery, this situation may persist into the Third Regulatory Period - which is inappropriate. The ERC therefore intends to fully address the under-recoveries carried over from the Second Regulatory Period during the Third Regulatory Period.

This will be achieved by adapting the annual revenue requirement for a Regulated Entity for the Third Regulatory Period as follows:

a) Determine the extent of under-recovery that arose during the first 30 months[48] of the Second Regulatory Period, or for the period July 1, 2007 to June 30, 2009. (It is appreciated that at the time of the Revenue Application, the full information up to June 30 2010 will not yet be available. Regulated Entities are therefore required to provide their best estimate of the under-recovery up to that date as part of their Revenue Application. During the course of the Regulatory Reset Review, the ERC will request the updated actual under-recovery figures up to June 30, 2010 from each Regulated Entity and will use these updated figures in its draft and final determinations on the price-control arrangements for the Third Regulatory Period.)

b) Calculate the escalated value of this amount as at the start of the Third Regulatory Period, using actual and projected CPI figures for the Philippines[49].

c) Divide the full escalated under-recovery figure in four parts and add one part to the annual revenue requirement of the Regulated Entity for each Regulatory Year in the Third Regulatory Period, after further escalating each part to its appropriate nominal value for the Regulatory Year in question.

The allowed annual revenue figures thus adapted will be used to determine the SMAP for the Third Regulatory Period.

In calculating MAP_{2011} and MAP_{2012} there may still be under-recoveries (or over-recoveries) that arose after December 31, 2009. These will be dealt with in terms of the normal mechanism described in the RDWR (Clause 4.3, or Section 8.2.5 below).

8.1.2 Treatment of regulatory interventions

In its final determinations on the price control arrangements for the Second Regulatory Period for some Regulatory Entities, the ERC applied regulatory interventions to avoid undue price-shocks to consumers. This has resulted in these Regulated Entities not being able to recover their full annual revenue requirement during the Second Regulatory Period. The ERC intends to address this situation in full during the Third Regulatory Period.

The manner in which these regulatory interventions will be recovered, will be as follows:

a) The regulatory intervention was determined at varying amounts for each Regulatory Year in the Second Regulatory Period. These annual amounts have to be escalated to

[48] Since the Regulatory Reset Period overlaps with later stage of the Second Regulatory Period, it is not possible to determine the full under-recovery for the whole Second Regulatory Period in time for the price reset for the Third Regulatory Period.

[49] These will be the same CPI figures used to derive the nominal operating, maintenance and capital expenditure figures for the Third Regulatory Period.

their value at the start of the Third Regulatory Period, using actual and projected CPI figures for the Philippines[50].

b) Divide the full escalated regulatory intervention figure in four parts and add one part to the annual revenue requirement of the Regulated Entity for each Regulatory Year in the Third Regulatory Period, after further escalating each part to its appropriate nominal value for the Regulatory Year in question.

The ERC may however implement other mechanisms as deemed appropriate and necessary.

8.1.3 Average price for distribution before the Third Regulatory Period

The calculation of the price path for the Third Regulatory Period relies partly on the average price for electricity distribution that a Regulated Entity received before the start of the Regulatory Period. This average price is the MAP for the last year in the Second Regulatory Period, or MAP_{2011}. (It is recognized that at the time of preparing for the Revenue Application, the final value for MAP_{2011} may not yet have been approved by the ERC. In this case, Regulated Entities are to use the MAP_{2011} value as calculated for their annual rate-application for RY2011 as basis for their Revenue Application. This will be updated to the actual approved value by the ERC during the course of the Regulatory Reset review period, for use in its draft and final determinations on the price-control arrangements for the Third Regulatory Period.)

8.1.4 Calculation of the efficiency factor (X-factor)

Calculation of the X-factor is based on a smoothing formula described in Clause 4.15 of the RDWR. It takes into account:

- the present value of the annual revenue requirement for a Regulated Entity for each year of the Third Regulatory Period. This in turn is based on the annual revenue requirements for a Regulated Entity as established through the use of the building block methodology, adapted for earlier under-recoveries or regulatory interventions as described above, and converted to present values by using the Regulatory WACC;
- the anticipated inflation rate for each year of the Third Regulatory Period;
- the forecast energy consumption for each Regulatory Year of the Third Regulatory Period;
- the opening maximum average price cap at the start of the Third Regulatory Period; and
- an initial correction factor (P_0) that will be determined by the ERC to assist with the reduction of price shocks during the transition to Performance Based Regulation.

The ERC's current view on these factors is described below.

[50] Ibid

8.1.5 Forecast inflation rates

For the Second Regulatory Period, the ERC has largely relied on forecasts of economic indices sourced from the Economist Intelligence Unit (EIU). Regulated Entities are invited to submit alternative CPI forecasts as part of their expenditure forecasts, which will also be reviewed by the ERC. The final figures, as approved by the ERC, will form the basis of the inflation forecasts required to calculate the X-factor.

8.1.6 Forecast energy consumption

The forecast energy consumption figures will be those submitted by Regulated Entities, approved or adapted by the ERC as described in Section 6 above.

8.1.7 Setting of the P_0 factor

The P_0 factor is an amount (in PhP/kWh) that the ERC will determine for each Regulated Distribution System to take into account a balance between windfall gains and losses in revenue resulting from external factors over which Regulated Entities have little or no control (such as windfall gains/losses arising from the re-valuation of the existing asset base). In addition, the factor will be used to reduce price shocks during the transition from the Second Regulatory Period to the Third Regulatory Period.

The level at which the P_0 factor is set influences the initial price cap at the start and, through the X-factor, the expected rate of increase of the price caps during the Third Regulatory Period. A higher P_0 factor will lead to a lower initial price cap and a lower X-factor, which will in turn lead to higher incremental price increases for each year in the Second Regulatory Period. Conversely, a lower P_0 factor will cause a higher initial price cap and lower increases during the Second Regulatory Period. In either case, the net present value of the forecast income stream approved by the ERC for the Second Regulatory Period (given the assumed inflation forecast) will be the same.[51]

The P_0 value is not allowed to fall outside the boundaries described in Clauses 4.15.3 (a) and (b) of the RDWR.

8.1.8 Opening price for the Third Regulatory Period

The opening maximum average price cap at the start of the Third Regulatory Period is calculated from the average price charged for electricity distribution as noted in Section 8.1.1, adapted for inflation, the P_0 factor and the X-factor. This calculation is given in Clause 4.15.4(a) of the RDWR.

8.1.9 Smoothed price path for the Third Regulatory Period

The smoothed annual average price caps for the Third Regulatory Period are based on the previous year's (smoothed) price cap, adapted for the forecast inflation and the X-factor. This is described in Section 4.15.4(b) of the RDWR. These prices are indicative only,

[51] Since the actual inflation rate is likely to vary from the estimate at the start of the Third Regulatory Period, there may be a difference in the actual income stream that would be derived from different settings of the P_0 and X-factors. This is, however, not likely to be material.

representing the best available view prior to the start of the next Regulatory Period. The actual MAP for later years will be different, as described in Section 8.2 below.

8.2 Price adjustments during the Third Regulatory Period

The RDWR provides for annual price resets, as described in Clause 4.2. The actual price caps will therefore be different from the estimated smoothed price path as described in Section 8.1.

At the start of the Third Regulatory Period, the opening maximum average price cap will be the smoothed price cap as calculated in Section 8.1.6. Thereafter, the price cap will be based on the actual weighted index, a performance incentive factor and correction factors, as described below.

8.2.1 Weighted Index for inflation and exchange rate changes

Calculation of the Change in Weighted Index applied to the maximum average price-cap is described in Clause 4.5 of the RDWR. This index is based on changes in the Philippines CPI and, if a trigger level is reached, changes in the PhP/US$ exchange rate and the USA consumer price index. Where this trigger has been reached, a weighting of 0.8 will apply to the Philippine CPI changes and a weighting of 0.2 to the combined exchange rate and USA CPI changes.

8.2.2 Determination of quarterly CPI figures

The annual change in the CPI considered for price setting for a Regulatory Year is based on a comparison of quarterly CPI figures. These quarterly figures are those for the year ending in the March quarter three months before the start of the Regulatory Year, and the same quarterly figures for the year ending on 31 March one year earlier. This process is described in Clause 4.5.2 of the RDWR.

The quarterly figures will be based on the All Items Consumer Price Index published by the Philippines National Statistics Office, using an index base of “2000 = 100”.[52]

8.2.3 Determination of quarterly exchange rate and USA CPI figures

Calculation of changes to the PhP/US$ exchange rate and changes in the USA CPI will be also be based on a comparison of quarterly exchange rate or CPI figures. The comparison will be for the year ending in the March quarter three months before the start of the Regulatory Year, against the same quarterly figures for the year ending on 31 March one year earlier. This is described in Clause 4.5.3 of the RDWR.

Historical exchange rate figures will be as published by the Bangko Sentral ng Pilipinas, expressed as PhP/US$1, based on the inter-bank mid-rates prevailing on each of the last 5 business days of a quarter.

[52] If the NSO should change the base value for reported CPI, all CPI values used for calculating the annual change in CPI should be adjusted to the same base value.

Historical USA CPI figures as published by the US Bureau of Labor Statistics for all urban customers, UC city average will be used. These will be for the last month of each quarter in series CUUR0000SAO.

The manner in which the RDWR refers to the quarterly figures is similar to that used for Philippine CPI figures and their interpretation should therefore also be the same.

8.2.4 *Changes to the weighted index*

In terms of Clause 4.20 of the RDWR, the ERC is to review the values of the W1 and W2 indices set out in Clause 3.3 of the RDWR, to determine whether they appropriately reflect the proportions of the operating, maintenance and capital expenditure forecast for the Regulatory Period undertaken or otherwise referable to a foreign currency.

As a result of this review, the ERC may change the relative weighting of the W1 and W2 factors. This revised weighting may be the same for the whole Regulatory Period or may differ between years. In addition, it may also differ between Regulated Distribution Systems.

8.2.5 *Over or under recovery of revenue*

The under/over recovery formula that will apply in determining the maximum average price-cap for a Regulatory Year is described in Clause 4.3 of the RDWR. The purpose of this recovery is to correct the maximum average price-cap where under- or over-recovery of revenue has occurred during the previous Regulatory Year, purely as a result of the actual weighted average tariff per kWh for a regulatory year being found to be higher, or lower, than that approved for that year. It excludes the influence of the incentive factor or tax corrections.

The correction factor allows for the impact of interest by using an interest factor (180 day weighted average Manila Reference Rate of the Bangko Sentral ng Pilipinas). It also allows for a penalty factor of an additional 4% to this interest factor if over-recovery exceeds 7% of the maximum average price-cap.

Included in the calculation of the correction factor, is an allowance for differences between the actual income received from the disposal of assets during a regulatory year and the forecast income from disposals for that year. The forecasts are as determined during the Regulatory Reset Process (see Section 5.4.4).

In Section 8.1.1 reference is made to excess under-recovery during the Second Regulatory Period and how this would be recovered. This recovery is over and above the normal recovery described above[53]. Note that for this excess under-recovery, no interest will apply.

8.2.6 *Tax adjustment factor*

The tax adjustment factor is to correct for over or under recovery of corporate income tax that has occurred during the previous Regulatory Year and is described in Clause 4.4 of the RDWR. This factor is determined by comparing the actual corporate income tax paid

[53] The excess under-recovery arose due to the fact that the normal recovery mechanism, in combination with the side constraints clause, made it impossible to full address earlier situations.

during a Regulatory Year for the provision of Regulated Distribution Services in a Regulated Distribution System, to the corporate income tax estimate that was made for that period during the regulatory reset.

However, since the income tax building block will be set to zero for the Second Regulatory Period, therefore the tax adjustment factor will not apply for this period.

8.2.7 Performance incentive factor

The performance incentive factor is described in detail in Section 10. The S_t term introduces a reward or penalty factor in the maximum annual price cap, based on the service performance of a Regulated Distribution System during the previous year.

8.3 Revenue earned on distribution network by non-regulated businesses

In calculating the correction factor for over/under recovery of revenue (Clause 4.3.1 of the RDWR) and the initial maximum average price-cap for Regulated Entities (Clause 4.5 of the RDWR), an allowance is made for the addition of revenue derived from related business undertakings that utilize the relevant Regulated Distribution System, but do not form part of Regulated Distribution Services. These business undertakings can be engaged directly or indirectly by a Regulated Entity.

Related business activities may include but are not limited to the following:

- Service fees (service connection, re-connection, etc.);
- Rental for distribution transformers;
- Rental for poles, boom and truck cane;
- Testing and calibration fees;
- Relocation and transfer fees;
- Inspection and installation fees;
- Illegal connection surcharge;
- Jobbing and contract fees;
- Engineering design on special projects;
- Rental of other utility property;
- Revenue from miscellaneous operations;
- Dividend income; and
- Bad debts recovery.

For the Third Regulatory Period, the related business revenue RBR_t (Clause 4.3.1) value will be set at 50% of the net income derived from related business activities. It is noted that in order to comply with the EPIRA (Section 26), Regulated Entities are required to maintain separate accounts for each related business undertaking, to ensure that they shall neither subsidize in any way such business undertakings nor encumber their distribution assets in any way to support such business.

8.3.1 Re-connection fees

Any fees payable to a Regulated Entity for the disconnection and later re-connection to the Regulated Distribution Network (after a temporary disconnection) should be added in full to the related business revenue described in Clause 4.3.1 or Clause 4.5 of the RDWR (i.e. at 100% of the net income derived from these activities). Most Regulated Entities provide these services using their existing staff and resources and therefore do not incur additional cost in doing so. The ERC considers reconnections as a core regulated activity and not as a true related business activity and also does not wish to encourage disconnections by allowing Regulated Entities additional revenue in carrying out this activity.

If a Regulated Entity employs external contractors to carry out customer disconnections and re-connections (after temporary disconnections) and, thus, has to incur additional costs specifically related to this service (which it would not have incurred if no disconnections or reconnections were required), these additional costs can be offset against the net cost of providing the service that is included in the related business revenue. These costs have to be demonstrated to the ERC as part of the Revenue Applications.

8.4 Development of financial model

In order to allow the ERC and Regulated Entities to calculate and analyze the maximum average price caps for each Regulated Distribution System, as well as to use during the annual price resets, the ERC has developed a detailed financial model. This model was used for the Regulatory Reset during the Second Regulatory Period and will be adapted and made available to the Regulated Entities for the Third Regulatory Period.

9. EFFICIENCY ADJUSTMENTS

The RDWR makes provision for efficiency adjustments, to ensure that a Regulated Entity has an incentive to reduce controllable costs to below those forecasts approved by the ERC as part of the regulatory reset process. This process is described in Clause 4.19 and Article IX of the RDWR.

Savings can be made on operating and maintenance expenditure and on capital expenditure. The value of capital expenditure savings shall be calculated as the product of the actual capital expenditure saving and the regulatory WACC. On the other hand, expenditure above the approved forecast levels will be to the account of a Regulated Entity.

It is emphasized that savings in capital expenditure relates to more efficient expenditure on approved projects, i.e. savings incurred during the construction of those projects due to better designs, construction procedures, use of lower-cost materials or similar factors when compared with the original forecasts. Reductions in capital expenditure due to the cancellation or postponement of approved capital expenditure projects are not considered to be savings and will be excluded from the efficiency adjustments (see also Section 12.2.2).

9.1 Rationale for the efficiency adjustments

Because of the price setting mechanism underlying the performance based regulation supported by the RDWR, during a Regulatory Period, Regulated Entities automatically retain any savings made on operating and maintenance expenditure as compared with their approved forecast expenditure. On the counter-side, any expenditure above the forecast expenditure will be to the account of the Regulated Entities.

Likewise, savings in capital expenditure to below the approved forecast values also accrue to the Regulated Entities, with the value of such savings calculated as the product of the actual capital expenditure saving and the regulatory WACC. Capital expenditure above the forecast values will be to the account of the Regulated Entities.

This is a key feature of performance based regulation, since over time it improves efficiency and reduces costs to consumers as those efficiencies are reflected in reduced expenditure forecasts during later Regulatory Resets. However, a problem arises at the end of a Regulatory Period:

- Expenditure forecasts at the start of a new Regulatory Period will largely reflect the actual expenditure trends of the previous Regulatory Period, including any savings incurred.
- In the next Regulatory Period Regulated Entities will therefore lose the benefit of any savings made during the previous Regulatory Period. This will reduce the incentive to make such savings, especially towards the end of the Regulatory Period where the benefit of the savings will only be retained for a short period.
- The incentive to achieve savings during the final year(s) of a Regulatory Period will be further reduced because of the relatively higher weighting that expenditure levels during these years is likely to carry in the approved expenditure forecasts for the next period.

- The above may result in an incentive to increase expenditure during the last year of a Regulatory Period. This is especially true for capital expenditure which can often be postponed relatively easily from earlier in a Regulatory Period to the final year(s).

The efficiency adjustment was designed to avoid this negative incentive and to strengthen the drive to procure efficiency gains. It allows efficiency gains to be carried forward for four years from the date when it occurred, regardless of whether that extends into the next Regulatory Period. On the counter side, efficiency losses (expenditure over the approved forecast amounts) will also be carried for a four year period.

It should be noted that efficiency gains on operating and maintenance expenditure relates to sustained gains, not one-of savings. Annual gains are therefore calculated over more than one year. Efficiency gains on capital expenditure are however considered on an annual basis. This is reflected in the manner in which the efficiency adjustments are calculated.

9.2 Overview of mechanism for efficiency adjustment

The mechanism for calculating the net efficiency gain for a Regulatory Year is described in Clause 9.2 of the RDWR.

The carry-over mechanism for an efficiency gain (or loss) achieved in a Regulatory Year is described in Clause 9.3 of the RDWR. In order to carry forward such a gain (or loss), it will be added to (or subtracted from) the allowed annual revenue for each Regulatory Year in the Third Regulatory Period up to and including the Fourth Regulatory Year following the occurrence of the efficiency gain (or loss). As such, it will be taken into account in the calculation of the Smoothed Maximum Average Price determined under Clause 4.15 of the RDWR.

The carry-over process is demonstrated in Table 9.1 below, using the OPEX portion for illustrative purposes only.

The efficiency gain (or loss) for the first year of the Third (and subsequent) Regulatory Period does not take into account the efficiency gain of the previous Regulatory Year. This is to reflect the fact that the approved expenditure level for the first Regulatory Year should already reflect any efficiency gains achieved during the preceding Regulatory Period.

Table 9.1: Illustration of efficiency adjustment (OPEX portion)

	Second Regulatory Period				Third Regulatory Period			
Regulatory Year	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Forecast Opex	1,000	1,025	1,050	1,075	1,070	1,090	1,110	1,130
Actual Opex	990	1,010	1,040	1,060	1,070	1,085	1,110	1,125
Efficiency gain/(loss)	10	5	(5)	5	0	5	(5)	5
Carry forward 2008		10	10	10	10			
Carry forward 2009			5	5	5	5		
Carry forward 2010				(5)	(5)	(5)	(5)	
Carry forward 2011					5	5	5	5
Total carry forward from 2nd Period					15	5	0	5
Carry forward 2012						0	0	0
Carry forward 2013							5	5
Carry forward 2014								(5)
Carry forward 2015								
Allowed opex expenditure (no carry-over)	1,000	1,025	1,050	1,075	1,070	1,090	1,110	1,130
Allowed opex in annual revenue (with carry-over)	1,000	1,025	1,050	1,075	1,085	1,095	1,110	1,135

As part of its Revenue Applications, each Regulated Entity should submit details of its actual operating and maintenance, and capital expenditure for each Regulatory Year of the Second Regulatory Period, up to the end of RY2010. It is appreciated that the Revenue Application follows very shortly after the end of RY2010 and that it may be therefore problematic for Regulated Entities to prepare audited full-year expenditure figures in the time available. In such case, Regulated Entities are to submit actual expenditure levels for the 11-month period ending on May 31, 2010 and provide an estimate of the actual expenditure levels for June 2010.

In addition, each Regulated Entity is to provide an updated forecast of its expected expenditure levels for RY2011. The ERC will consider this forecast along with its analysis of the actual expenditure figures to derive the Net Efficiency Adjustment that should be carried over to the Third Regulatory Period.

The actual expenditure levels for RY2011 will only be provided to the ERC during the annual rate reset for RY2013. At that time the ERC will assess the difference between the forecast figures included in the Net Efficiency Adjustment for the Third Regulatory period and the actual expenditure incurred by a Regulated Entity[54], and will correct for this difference.

In most cases the difference will be corrected for during the Regulatory Reset for the Fourth Regulatory Period. This will be done by adjusting the Net Efficiency Adjustment for the Fourth Regulatory Period to reflect any excess- or under-recovery on this factor for the Third Regulatory Period.

Should the difference however be so large that it would have had a material impact on the SMAP for the Third Regulatory Period had the correct values been known, the ERC may decide that it constitutes cause for a re-opening event. In such a case, a new X-factor will be calculated for the remainder of the Third Regulatory Period.

The ERC notes that there may be an asymmetric effect in the calculation of efficiency penalties should a Regulated Entity over-spend on its operating and maintenance cost, especially late in a Regulatory Period. This will be taken into account in the assessment of the efficiency carry-over and, if the ERC finds that a Regulated Entity has been operating sufficiently efficiently in spite of over-spending against its the allowed operating and maintenance revenue, it may decide to waive or reduce the efficiency losses carried over to the Third Regulatory Period.

9.3 Adjustment of expenditure forecasts

In Clause 9.2.4 of the RDWR provision is made for the possible adjustment by the ERC of the capital or operating and maintenance expenditure forecasts for a Regulated Entity. This is specifically for the purpose of calculating the net efficiency adjustments and is not intended to in any way adjust the allowed annual revenue forecasts approved in the ERC's final determination on the price-control arrangements for the Second Regulatory Period.

For purposes of the net efficiency adjustments, such adjustments of the approved forecast expenditures may be required to reflect:

[54] This will include the any difference for the last month of RY2010.

- changes in the scope of services and activities undertaken by a Regulated Entity from those that formed the basis of the approved forecasts;
- material differences between the forecast electricity demand levels experienced on a Regulated Distribution System and those forecast,[55] as measured by the co-incident maximum demand;[56]
- material differences between the actual Philippines CPI as compared with those forecast;[57] and
- material differences between the actual PhP/US$ exchange rates as compared with those forecast[58].

To allow the ERC to effectively assess the efficiency adjustments, supporting information must be provided by each Regulated Entity to demonstrate that efficiency gains arose as a result of actual improved operating or investment behaviour, rather than as a result of any of the above factors.

Adjustments will be made at the discretion of the ERC, after notifying Regulated Entities and taking into account any submissions in this regard from the Regulated Entities.

9.4 Maintaining service delivery levels

The ERC is concerned that expenditure efficiencies may be gained at the expense of service and network performance levels. In the RDWR, provision is therefore made for net efficiency adjustments to be excluded during the Third Regulatory Period if it is found during the regulatory reset that service delivery levels have deteriorated during the Second Regulatory Period.

The service measures that will be monitored are those discussed in Section 10.3 and the historical and actual performance information submitted by Regulated Entities under the performance incentive scheme will be used to assess performance against historical levels. To determine whether performance levels have slipped below historic levels, the ERC will calculate the average performance over the Second Regulatory Period and compare this against the S-factor average performance targets set for the Second Regulatory Period. Regulated Entities are therefore required to submit as part of their Revenue Application their actual performance against all the performance incentive scheme measures for each of the three Regulatory Years ending on June 30, 2010[59]. In case the full-year verified figures for RY2010 is not available at the time, a full-year projection is to be made based on the performance up to May 31, 2010.

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[55] Material differences are defined as those cases where the actual demand is greater than 105% or less than 95% of the forecast demand.

[56] See Section 6.1.1 for a discussion on the measurement of maximum demand.

[57] A material difference is when the actual CPI adjustment over a Regulatory Year varies by 10% or more from that forecast during the Regulatory Reset.

[58] A material difference is when the actual PhP/US$ exchange rate CPI adjustment over a Regulatory Year varies by 10% or more from that forecast during the Regulatory Reset.

[59] Given the date of the Revenue Application, the RY2011 figures will not be available.

Regardless of the above, the ERC is still concerned about the possible impact on future network performance and delivery capacity of curtailing especially capital expenditure. The short-term impact of inadequate capital expenditure may not be noticeable in a single Regulatory Period, but that the medium to longer term impacts may be dire.

The ERC therefore intends to closely monitor capital expenditure savings to ensure that such savings will not be detrimental to the effective longer term operation, delivery capacity and service performance of a Regulated Distribution System.

In particular, the net capital efficiency adjustments are not intended to arise from savings made by deferring or canceling capital expenditure projects approved during the regulatory reset. Where such deferments or cancellations therefore occur, the ERC may adjust the capital expenditure forecasts for purposes of calculating the net capital efficiency adjustment.[60]

If in terms of Clause 12.2 of the RDWR an X-factor adjustment event occurs as a result of deferred capital expenditure on Significant Projects, the subsequent adjustment made to the approved capital expenditure program will also be applied for purposes of calculating the net capital efficiency adjustments.

[60] This is unless a Regulated Entity can prove to the ERC that the postponement of a project will result in a higher overall economic benefit due to external factors such as changes in technology, more certainty with regard to developments in load centers or patterns, or the completion of other works which would substantially reduce the cost of a project or add to the value it would contribute.

10. PERFORMANCE INCENTIVE SCHEME

In terms of Clause 4.18 of the RDWR, the ERC must implement a performance incentive scheme that rewards each Regulated Entity for achieving specified performance target levels, and penalizes it for failing to achieve specified target levels. This incentive scheme is further described in Article VIII of the RDWR. The ERC's proposed approach to the performance incentive scheme is discussed in this Section.

During the Second Regulatory Period the ERC allowed Regulated Entities to adopt an interim performance scheme while preparing to be ready for the full scheme by the Third Regulatory Period. The scheme described below will therefore be required from all Regulated Entities.

10.1 Purpose of the performance incentive schemes

The performance incentive scheme is intended to ensure that:

- customers receive the full benefit from the performance based regulation scheme promoted under the RDWR;
- service quality levels do not deteriorate as a result of incentives to reduce expenditure;
- the general levels of awareness and transparency of performance levels for customers and Regulated Entities alike are raised; and
- Regulated Entities have a direct incentive to improve performance levels.

10.2 Overview of the incentive scheme

The performance incentive scheme that will apply for the Third Regulatory Period will have three main streams, as described below.

a) Price-linked incentive scheme

The performance of Regulated Distribution Systems will be assessed against a number of network performance and service performance measures.[61] If performance levels exceed predetermined targets, Regulated Entities will be financially rewarded or, if performance levels fail to meet predetermined performance targets, Regulated Entities will be financially penalized.

The reward or penalty will take the form of the S-factor to be used in the calculation of the maximum average price-cap (see Section 8.2.7). The S-factor will be a weighted performance measure, based on the performance levels achieved against a number of indices over the calendar year preceding each Regulatory Year.

[61] For the purposes of this paper, network performance measures refer to those indices measured directly in terms of Distribution System performance, usually expressed as technical factors. Service performance measures refer to those indices relating directly to the performance of the staff supporting the operation of the Distribution System, usually expressed in terms of the time taken to complete actions, or the number of times actions exceeded (or failed to exceed) target levels.

b) Guaranteed Service Levels

A system of Guaranteed Service Levels (GSLs) will be introduced for each Regulated Distribution System, in terms of which customers will receive certain guarantees with regard to the responsiveness and effectiveness of Regulated Entities. If these GSLs are not met, predetermined penalties will be paid by the Regulated Entities directly to customers.

c) Information disclosure

The performance of Regulated Distribution Systems against a further number of performance indices (network and service related) will be regularly measured and published.

The three streams of the eventual performance incentive scheme are discussed below.

10.3 Price-linked incentives

10.3.1 Capturing the performance rewards or penalties

For the proposed direct reward-based incentives, the price-cap formula (Clause 4.2.1 of the RDWR) includes an S-factor, as follows:

$$MAP_t = [MAP_{t-1} \times \{1 + CWI_t - X\}] + S_t - K_t + ITA_t$$

where S_t is the performance incentive factor calculated as described in Section 10.3.4 below. This factor can be zero, positive or negative, depending on whether actual performance against the (weighted) majority of the indices has exceeded or has fallen below the performance target discussed below.

For the price reset for RY2012 the S-factor will be fully based on performance during the Second Regulatory Period, applying the performance incentive scheme approved for this period. For RY2013, the assessment period will still cover half of RY2011, which falls in the Second Regulatory Period. From a practical perspective, the ERC therefore proposes to also base the S-factor for RY2013 on the performance incentive scheme approved for the Second Regulatory Period. (This also allows Regulated Entities a further year to implement improvements prior to adopting the new performance targets for the Third Regulatory Period, as described below.)

10.3.2 Setting performance targets for the Third Regulatory Period

New performance targets will be set for the Third Regulatory Period (to apply from RY2014). In terms of the RDWR (Clause 4.18.4) the ERC can select to base the calculation of the performance targets on the historical actual performance levels of Regulated Distribution Systems, or may reflect a measure of improvement on historical targets. For the Third Regulatory Period, the ERC intends to in some instances introduce improved targets.

The purpose of introducing targets that require improvements over historical performance is threefold, to :

- address outlying poor performance by Regulated Entities against one or more performance indices;
- reward Regulated Entities that perform exceptionally well against one or more performance indices; and
- ensure that a strong incentive remain for Regulated Entities to improve the performance of Regulated Distribution Systems.

To assess the relative performance of Regulated Entities in terms of their service performance and the performance of their Regulated Distribution Systems, the ERC intends to benchmark the performance of all Regulated Entities against each other. It may also introduce a level of international benchmarking for comparative purposes, although international benchmarks will not be used in setting performance targets for Philippines Regulated Entities.

The ERC recognizes that making a direct comparison between Regulated Entities is inappropriate, unless sufficient allowance is made to reflect the important differences that exist between Regulated Entities, their physical and demographic environment and the nature of their Regulated Distribution Systems. Normalizing measures will therefore be introduced as part of the benchmarking exercise. These normalizing measures may include a consideration of one or more of the following (as well as other factors not listed here):

- the customer density of networks (consumers per network unit length);
- the energy density of networks (energy consumption per network unit length);
- location of networks and the physical environment;
- consumption levels;
- average distribution pricing (to reflect price/quality trade-offs); and
- societal, political or demographic factors.

Where, as a result of the benchmarking, it is found that a Regulated Entity or its Regulated Distribution System is performing well below the average benchmarked levels on a particular performance index, its performance target for that index may be set at levels closer to the average. The ERC recognizes that achieving substantial performance improvements in the short term may not be realistic and could be expensive. In addition, it is also recognized that a significant degree of year-to-year variability exist for most performance measures, and that single-year figures may be unduly influenced by exceptional events. These factors will be taken into account when setting the performance targets.

Conversely, if it is found that a Regulated Entity performs significantly better than the benchmark average against a performance index, the ERC may decide to somewhat relax its performance target, or provide a larger incentive to maintain these performance levels maintained[62].

[62] While it is not desirable for service levels to deteriorate, the ERC is aware that setting performance targets based on exceptional historical performance puts a higher achievement hurdle for well-performing Regulated Entities than for poorly performing entities. It is normally considerably easier to effect improvements from a low starting base than from a level where performance is already good.

The ERC intends to employ Regulatory Reset Experts to assist it with the benchmarking. The benchmarking methodology as well the results and manner in which the ERC intends to adopt these results in setting performance targets will be subject to public consultation.

10.3.3 Service performance indices to be measured

For the Third Regulatory Period performance incentive scheme, the following service performance indices will be included in the S-factor :

Network Performance Measures

a) System average interruption frequency index (SAIFI). A measure of the average number of sustained service interruptions experienced per customer over the measurement period.

b) Customer average interruption duration index (CAIDI). A measure of the average duration of sustained service interruptions over the measurement period.

c) Planned system average interruption duration index (SAIDI). A measure of the average duration of planned sustained service interruptions for all customers over the measurement period.[63]

d) Voltage regulation. A measure of the probability of Distribution System voltage levels falling outside the boundaries prescribed in the Distribution Code.

e) System losses. An indication of total losses on a Regulated Distribution System, including technical and non-technical losses, or the difference between the energy obtained from Grid Connection Points and connection points to embedded generators, and that delivered and invoiced to End Users.

Service performance measures

f) Time to process applications for Regulated Distribution Services.

g) Time to connect premises to the Regulated Distribution System after compliance with all government and Regulated Entity requirements.

h) Percentage of calls answered at the call center (or equivalent) within a predetermined time.

The proposed definitions and calculation of the various indices are discussed in appendix C.

The ERC has decided to continue with the planned SAIDI as a separate index. The impact of planned outages on customers is usually less severe than that of unplanned outages. Planned outages are also predominantly under the control of network managers and measures can often be taken to reduce their impact. It is therefore a good measure of the performance of Regulated Entities in those aspects of network management that they can control.

[63] Planned outages are those over which Regulated Utilities can exercise a large degree of control and for which advance notice, longer than 72 hours ahead, will be given to customers.

Unplanned SAIDI will not be separately measured – it is implicit in the SAIFI and CAIDI figures (SAIDI is the product of these two measures, and unplanned SAIDI is merely the difference between total SAIDI and planned SAIDI).

The ERC notes that in terms of the Distribution Code (Section 3.3.3.2 [a]) outages that occur on the secondary lines of Distribution Systems are excluded from the SAIFI and SAIDI calculations (and, by implication CAIDI). This exclusion is presumably to make allowance for the difficulty that Regulated Entities may have in measuring and recording such outages. However, from a customer perspective it is irrelevant whether a disruption to their service is a result of an outage on the primary or secondary distribution network. Unless there are compelling reasons to the contrary, the ERC therefore intends to widen its definition of SAIDI, SAIFI and CAIDI to include outages on at least the larger secondary lines of a Distribution System. [64] It is not intended to widen this definition to include outages to a single service drop or small groups of customers,[65] but outages on major low voltage lines or distribution transformers should be included.

Regulated Entities already face a downside potential from the system loss cap that is imposed on Regulated Distribution Systems.[66] It is therefore the intention that the system loss performance index will not have a negative measure– it will be zero or positive only. Only performance better than the current systems loss cap will be rewarded.

The ERC recognizes that not all Regulated Entities may have formal call centers to respond to customer queries. Such a center, or an equivalent arrangement is however considered a fundamental requirement for providing efficient customer service and it is therefore encouraged by means of the incentive scheme. Regulated Entities without a formal call centre are required to describe to the ERC how they deal effectively with customer requests, and how the performance of this arrangement can be effectively measured.

10.3.4 Calculation of the S-factor

The details for the calculation of the S-factor are described in Appendix B to the RDWR and are therefore not repeated here.

10.3.5 Weighting of the performance indices

In Clause 8.2.3 (c) of the RDWR, it is specified that the total level of the rewards or penalties under the performance incentive scheme for any Regulatory Year should not exceed 3 % of the allowed annual revenue for a Regulated Distribution System for that year. As the performance incentive scheme will have two streams involving possible changes to the annual revenue that can be earned, the ERC has decided to continue with the following ceilings on these streams:

[64] In the absence of meters that automatically detect outages on secondary systems, it may be possible to rely on field records of reported outages – in other words use the time between a fault being reported to a Regulated Entity till the time that it is reported to be fixed.

[65] Such outages are unlikely to register on the network wide SAIDI or SAIFI statistics in any case.

[66] Distribution Utilities are only entitled to recover losses up to the capped percentage level. Any losses in excess of this are to their account.

a) The maximum value of the direct reward-based incentive scheme in any year will be capped at 2.5% of the annual revenue requirement.

b) The allowance for the GSL scheme will be set at 0.5 % of the average annual revenue requirement for the Third Regulatory Period, as calculated before the GSL scheme is taken into account[67].

The relative weightings of the various performance indices in the calculation of the S-factor is proposed as set out in Table 10.1.

Table 10.1: Proposed weightings for the S-components

Component	Symbol	Weighting
SAIFI	W_{SAIFI}	0.20
CAIDI	W_{CAIDI}	0.20
Planned SAIDI	W_{SAIDI}	0.15
Voltage regulation	$W_{VoltViol}$	0.10
System losses	$W_{Sysloss}$	0.05
Time to process applications	$W_{\Pr oc}$	0.10
Time to connect premises	W_{Con}	0.10
Call-center performance	W_{Call}	0.10

10.3.6 Determination of the performance levels for the various performance indices

The derivation of the base performance targets is discussed in Section 10.3.2. The reward or penalty levels are set at various levels around these base values, as described in Appendix B of the RDWR. In general these performance bands are set at multiples of the historical annual standard deviation in the performance figures for the various indices.

Although the ERC will collect actual performance data as part of the benchmarking exercise described in section 10.3.2, Regulated Entities are to submit their actual performance levels against each of the performance indices as part of their Revenue Applications. Performance levels for each index for each of the four Regulatory Years ending on June 30, 2010 are to be provided. In addition historical performance levels for the four calendar years preceding the Second Regulatory Period are also to be provided. (These can be the same figures submitted by Regulated Entities during the Regulatory Reset Period for the Second Regulatory Period.)

10.3.7 Excluded events

There are a number of external events which can have a substantial impact on the actual performance of Regulated Distribution Systems against performance indices, but that are predominantly outside the control of Regulated Entities. The ERC will allow these events to be excluded from the statistics used to calculate network or service performance.

[67] Using the average rather than the actual annual amounts is necessary to allow fixed penalty payment amounts to be set for the whole of the Regulatory Period.

Events of which the impact on the performance of a Regulated Distribution System will generally be excluded are :

- supply interruptions made at the request of a customer;
- load shedding due to a shortfall in generation;
- supply interruptions caused by a failure of the transmission network;
- supply interruptions caused by a failure of a transmission connection asset, but only to the extent that the interruptions were not due to inadequate planning of transmission connections on the part of a Regulated Entity other than TransCo/NGCP;
- widespread supply interruptions due to rare and extreme events which were not reasonably able to be foreseen, or if they could be foreseen, for which the impact could still not be effectively mitigated; and
- failure of a customer to respond to a reasonable request, or to allow access to a site.

A Regulated Entity wishing to exclude the impact of a certain event from the calculation of the service performance incentive scheme would need to provide the ERC with the following:

- a detailed description of the nature of the event for which an exclusion is sought and the reasons justifying the exclusion of the event, including the provision of supporting evidence;
- evidence of the impact of the event on the Regulated Distribution System reliability performance, for each of the measures adversely affected;
- a description of the steps that the Regulated Entity took to mitigate against or respond to the events; and
- evidence that the Regulated Entity was unable to further mitigate against the impact of the event.

For network-related indices, the ERC will continue to use the 2.5 beta method, developed by the Institute for Electrical and Electronic Engineers (IEEE)[68] to identify major event days.[69]

Further tests can then be applied to determine the main cause(s) for the major event days, isolating, where appropriate, the underlying event and formally classing it as "severe". These tests include assessing the nature and rarity of an event, the ability to foresee and prepare for an event, the ability of distribution companies to mitigate the effects of an

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[68] IEEE Power Engineering Society - (2004, May). IEEE Std 1366TM – 2003. IEEE Guide for Electric Power Distribution Reliability Indices - New York, USA. Institute of Electronics and Electrical Engineers (IEEE)

[69] In essence, the method assumes a lognormal distribution for daily SAIDI figures. The average and the standard deviation of the natural logarithm of daily SAIDI figures measured over a substantial period are calculated. By adding a margin or band to this based on a number of standard deviations (2.5 standard deviations is recommended), a boundary is established. Based on the distribution, days for which the (natural log of the) SAIDI fall beyond this boundary are sufficiently rare with an impact sufficiently extreme to warrant further consideration.

event, and the reaction of Regulated Entities after the event. If an event is classed as extreme, its impact on the daily SAIDI would be excluded.

The IEEE test refers to SAIDI only. It is however often appropriate to identify extreme events by their impact on the daily SAIDI of a Regulated Distribution System, but then to exclude the impact of such an event on the other performance indices as well.

The intention of the test is to identify extreme events. The ERC is well aware that there are numerous events impacting on the performance of distribution networks over which Regulated Entities have little or no control. However, the vast majority of these events would not be of such magnitude that they could overwhelm the ability of a Regulated Entity to respond effectively, or would unduly distort the annual performance statistics. In addition, similar events have occurred in the past and their impact is therefore included in the historical figures on which the performance targets are based.

10.4 Guaranteed Service Levels

The ERC will continue with a GSL scheme during the Third Regulatory Period. In terms of this scheme, Regulated Entities will compensate a consumer directly if certain service delivery performance thresholds are not met. The indices described below will be used.

10.4.1 GSL indices and payment levels

The indices that will be included in the GSL scheme are listed below. Actual targets will be established during the Regulatory Reset Process, based on the information submitted by Regulated Entities as part of the Revenue Applications.

The proposed GSL measures for the thresholds are:

a) GSL1 : a customer in an urban or sub-urban part of a Regulated Distribution System experiencing more than the target time of sustained interruptions over any Regulatory Year or a customer in a rural part of a Regulated Distribution System experiencing more than the target hours of sustained interruptions over any Regulatory Year;

b) GSL2 : a customer in an urban or sub-urban part of a Regulated Distribution System experiencing more than the target number of sustained interruptions in a Regulatory Year or a customer in a rural part of a Regulated Distribution System experiencing more than target number of sustained interruptions in a Regulatory Year;

c) GSL3 : restoration of service to a customer after a fault on the secondary side of a Regulated Distribution System, including the service drop, does not occur within the target time of the fault occurring; and

d) GSL4 : the Regulated Entity failing to provide a connection to a customer on the day promised, with cumulative payments applying for each day that a connection is later than promised. (Alternatively, depending on how performance against this index was historically measured, this GSL index could also reflect the instances where connections are not provided within the guaranteed period.)

10.4.2 Determining the penalty levels

Setting appropriate GSL performance levels requires current information on actual performance against the indices. The ERC will collect the information from Regulated Entities over their performance during the Second Regulatory Period to determine the penalty levels that will apply for the Third Regulatory Period when GSLs are not met.

The methodology that will be used to establish the penalty levels is described in Appendix B of the RDWR.

10.4.3 Adapting revenue requirements

As before, during the Third Regulatory Period, it is intended to make an additional allowance in the allowed annual revenue for each Regulated Entity, to cover the anticipated amount that would be payable towards the GSL scheme. It will be viewed as an additional operating expense for each Regulatory Year.

As such, Regulated Entities who manage to perform better than forecasted against the GSL will be allowed to retain the extra revenue, potentially also as part of their future efficiency adjustments. Conversely, those Regulated Entities that pay out more penalties than allowed for, will bear the additional cost, potentially also as part of their future efficiency adjustments.

This is to allow Regulated Entities the option of incurring additional expenditure to avoid penalty situations, or to remain revenue neutral if they maintain current performance levels.

10.4.4 Reporting GSL performance to the ERC

The ERC requires each Regulated Entity to submit an annual report (with monthly breakdowns) on its performance against the GSL indices for each Regulatory Year. This report should include details of all GSL payments made, the value of these payments and the circumstances giving rise to these payments. Where the contribution of events has been excluded from the GSL calculations, these events also have to be identified, with the reasons why their impact was excluded.

This report is to be submitted to the ERC not later than December 31 following each Regulatory Year.

10.4.5 Improvement of service levels

It is generally the intention of the ERC to base the GSL performance targets on the actual historical performance of a utility. However, in extreme cases where such performance is deemed to be far below average, the ERC may impose improvement targets.

Such decision will be influenced by comparison of the GSL performance between Regulated Entities. These indices will therefore also be tested as part of the benchmark review discussed in Section 10.3.2.

10.4.6 Excluded events

As with the price-linked incentive scheme, there are external events which can have a substantial impact on the actual performance of Regulated Entities against the GSL scheme, but that are predominantly outside their control. The ERC will allow these events to be excluded from the scheme. The events that will be excluded are similar to that discussed earlier:

- supply interruptions made at the request of a customer;
- load shedding due to a shortfall in generation;
- supply interruptions caused by a failure of the transmission network;
- supply interruptions caused by a failure of a transmission connection asset, but only to the extent that the interruptions were not due to inadequate planning of transmission connections;
- widespread supply interruptions due to rare and extreme events which could not be reasonably foreseen, or if they could be foreseen, for which the impact could still not be effectively mitigated; and
- failure of a customer to respond to a reasonable request, or to allow access to a site.

A Regulated Entity wishing to avoid a penalty payment arising as a result of one of these events has to notify the ERC and the affected customer(s) of the reason for this. In addition, the following details have to be provided to the ERC:

- a detailed description of the nature of the event for which an exclusion is sought and the reasons justifying the exclusion of the event, including the provision of supporting evidence;
- evidence of the impact of the event on the Regulated Distribution System reliability performance, for each of the measures adversely affected;
- a description of the steps that the Regulated Entity took to mitigate against or respond to the events; and
- evidence that the Regulated Entity was unable to further mitigate against the impact of the event.

After assessing whether a penalty can indeed be disallowed or should remain in place, the ERC will notify the Regulated Entity of its decision. It will be the responsibility of the Regulated Entity to further communicate the decision to the affected customer(s).

10.5 Information disclosure

The third component of the performance incentive scheme is the measurement and disclosure of further performance data. Regulated Entities will be required to measure the performance of each Regulated Distribution System against the following indices:

Network performance indices

a) momentary average interruption frequency index (MAIFI);

b) frequency of tripping events per 100 circuit-km;

Service performance indices

c) average time to respond to queries and complaints;

d) average time to reconnect a service after payment of all dues and customer's compliance with the Regulated Entity's and Local Government Unit's requirements

The information has to be collected and supplied to the ERC on an annual basis indicating the annual, quarterly and monthly totals.

The ERC intends to eventually publish the information disclosure data (and the performance against the PIS indices) for all Regulated Distribution Systems on an annual basis. Submissions should be on a calendar year basis, submitted not later than February 28 of the year following that for which performance had been measured.

10.6 Measurement ability and details

A common thread throughout the whole performance incentive scheme is the requirement for performance information to be measured by Regulated Entities for each Regulated Distribution System. It is essential that information is both exhaustive and accurate.

Although Regulated Entities have had the Second Regulatory Period to improve their measurement capabilities, the ERC is still concerned about the ability of some Regulated Entities to adequately measure all the information that is required.

In addition to its concerns about the ability of Regulated Entities to adequately measure the required performance data, the ERC is also concerned about the accuracy of such data. The ERC therefore requires that all performance information submitted to the Commission be accompanied by a declaration that the information provided has been verified and is substantially correct as provided. This declaration has to be signed by the President or Chief Executive Officer (or equivalent) of the Regulated Entity and the Member of the Board (or equivalent) of the Regulated Entity to whom this responsibility has been delegated.

In addition, at the end of every Regulatory Year, a statement is required from a registered auditor to accompany the full-year performance statistics for each Regulated Distribution System. The auditor has to certify that the implementation of the methodology for the performance incentive scheme has been audited and a representative cross- section of calculations verified, and that these were found to be free of substantive errors.[70]

The ERC may from time to time conduct its own audits on the accuracy of measured information. The ERC will draw up the audit scope and appoint an auditor, but the cost for such audits will be borne by Regulated Entities. Not more than one such audit will be conducted during any Regulatory Year for a single Regulated Entity, unless there is compelling evidence to suggest that the performance information submitted by the Regulated Entity is not of a sufficient standard and that further audits are warranted. Regulated Entities are to maintain all records that would be necessary for the ERC's auditor to reconstruct and verify the calculations made for the monthly and annual information submissions. As a minimum, Regulated Entities have to maintain detailed records of the following:

- outages, describing the date, nature and class of outages, the duration, the parts of the network and customers affected and the cause of the incidents ;

[70] The ERC recognizes that it is unrealistic to expect an external auditor to comment with authority on the accuracy of the base data from which the reliability calculations are made.

- customer requests for services and other customer enquiries, including the time and date they were made, and the time and date of various milestones reached in processing them;
- technical quality measurements taken, including the date and position of measurements, the person(s) taking the measurements and the measurement results;
- all equipment used to take measurements on the network, including calibration and service details; and
- details of all calculations made to prepare the monthly data submission to the ERC.

Should it become apparent during an audit that the information provided by a Regulated Entity for any Regulated Distribution System is not sufficiently accurate, the ERC may:

- request a Regulated Entity to prepare and submit new calculations;
- cancel any performance incentive rewards due to a Regulated Entity where these relate to inaccurate measurements or reporting;
- require Regulated Entities to replace measurement equipment and implement better measurement techniques; and
- appoint an independent third party selected by the ERC to undertake the required measurement and information processing, where such an appointment will be at the Regulated Entity's expense.

10.7 Data required

Templates for the historical and the quarterly performance data that has to be submitted to the ERC by Regulated Entities for each Regulated Distribution System will be provided at the Pre-filing conference for the Revenue Applications.

Data submissions and the dates for these will also be considered as part of the ERC's planned performance quality benchmarking project.

11. ANNUAL ADJUSTMENT OF TARIFF RATES

The process for the annual adjustment of the maximum distribution wheeling rates that may be charged for the provision of Regulated Distribution Services on any Regulated Distribution System during the Second Regulatory Period is described in Article VI of the RDWR. It is further developed in the DSOAR, particularly with regard to converting the maximum annual price-cap to rates (DSOAR, Clause 5.3.2). In addition, the components used in the annual calculation of the maximum average price caps are discussed in Section 8.2 above.

The Regulatory Year for which new rates are to be determined is referred to as the Application Year.

11.1 Overview

The timetable for the annual rate setting process for an Application Year as described in the RDWR is set out in Table 11.1 below. Note that some of the dates have been amended by the ERC, to allow the Regulated Entities more time to respond to queries.

Table 11.1: Annual rate setting timetable

Action	Date required
Gathering of all the required data by Regulated Entities for the rate adjustment, as prescribed in the RDWR	Month of February preceding the Application Year
Submission of rate adjustment information and rate filing for the wheeling rates to apply during the Application Year for each Regulated Distribution System by Regulated Entities to the ERC	March 31 preceding the Application Year
ERC to pass requests for further information to Regulated Entities	Before May 14 preceding the Application Year
Further information provided by Regulated Entities	Before May 20 preceding the Application Year
Public hearings on the rate filings	Before May 14 preceding the Application Year
Determination by ERC of whether proposed wheeling rate for the Application Year can be implemented as submitted, or whether amendments are necessary	May 31 preceding the Application Year
Public notification of the new distribution wheeling rates	June preceding the application year
Implementation of the wheeling rates, if accepted by ERC in submitted form	July 1 of the Application Year
Notice of amendments required provided to Regulated Entities by the ERC, consultation, amendment of information and setting of wheeling rates	As appropriate, but after May 31 preceding the Application Year
Public notification of amended wheeling rates	June 1 preceding the Application Year
Implementation of the wheeling rates after direction on amended rates is given by the ERC	30 days after the direction is given (but not before July 1 of the Application Year)

Following decisions by the Supreme Court on the filing procedures for rate adjustments, the annual rate adjustments have to be treated as formal rate cases. Regulated Entities will therefore be required to submit formal rate applications which will be subjected to a formal public hearing process. The ERC policies in this regard should be strictly followed.[71]

For the sake of clarity, it is noted that the public hearing process will be limited to the rate adjustments and the factors used to determine this. No consultation or discussion will be entertained on aspects which had previously been the subject of consultation and hearings and on which earlier final decisions have been made by the ERC.[72]

The information to be submitted by Regulated Entities to the ERC as part of their submission for an annual rate setting is described in Clause 6.2.1(a) of the RDWR. This information is to accompany a Regulated Entity's proposal for the maximum average distribution wheeling rates that may be charged during the Application Year. All calculations made and the source of all data used in these calculations must be clearly indicated. The proposal and supporting data is to be submitted in soft and hard copies to the ERC.

In addition to the data specified in the RDWR, Regulated Entities are required to also submit information pertaining to the performance of each Regulated Distribution System against the performance incentive indices used for the direct reward-based incentive scheme for the calendar year preceding the Application Year. These are the performance indices described in Section 10.3.3 above.

Each rate for each Customer Segment that will be applied by a Regulated Entity for each Regulated Distribution System during the Application Year must be detailed in the proposal, together with a statement demonstrating the compliance of those proposed rates with the requirements of the RDWR and the DSOAR. If the distribution rate structure of a Regulated Entity is kept unchanged from previous rate filings, this should also be indicated.

The rates submission has to be certified by the President, CEO (or equivalent) of the Regulated Entity and the Chairman of its Board of Directors (or equivalent) as being correct and in accordance with the RDWR and the DSOAR.

In cases where delays arise in the approval of annual rate settings, where such delays are not caused by any action, inaction or omission by a Regulated Entity, if the exigencies and circumstances warrant it, the ERC may issue a Provisional Authority for the implementation of new rate schedules.

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[71] This is described in the ERC publication titled *"Energy Regulatory Commission's Rules of Practice and Procedure"*

[72] For example the methodology used to determine the X-factor and the Final Determination on this, or the structure of a Regulated Entity's distribution rates if this is not changed from the initial application made before the start of the Second Regulatory Period.

11.2 Converting maximum annual prices into rates

The maximum average price cap is a company-wide measure and does not address individual rate elements. It is therefore necessary to convert this into rate elements. The general methodology for this conversion is described in Clause 5.3.2 of the DSOAR.

Essentially, the steps proposed in the DSOAR to calculate the rates for an Application Year are as follows:

a) Calculate the historical revenue earned from each Customer Segment i for the historical year t ($CR_{i,t}$).

b) Calculate the average historical rate for each customer segment over the previous 12 months ($CS_{i,t} = \frac{CR_{i,t}}{CQ_{i,t}}$), where $CQ_{i,t}$ is the energy consumed by each customer segment i (kWh), during historical year t.

c) Compute the projected revenue for the next year per customer segment based on the historical rate and forecast consumption ($CR_{i,t+1} = CS_{i,t} \times FQ_{i,t}$).

d) By adding the projected revenue for each Customer Segment, the total projected revenue for the Application Year, based on historical rates, is calculated. ($CR20YR = \sum CR_{i,t+1}$)

e) Determine the proportion of revenue to be recovered for each customer segment based on the projected revenue. ($\frac{CR_{i,t+1}}{CR20YR}$)

f) Compute the total revenue (TR) for the Application year by multiplying the maximum average price cap (MAP_t) with the forecast energy consumption for the Application Year. ($TR = MAP_t \times FQ_t$)

g) Allocate the total revenue requirement (TR) for the Application Year to each Customer Segment ($TR_{i,t}$) based on the proportion of projected revenue from each Segment to the total revenue projected as computed under item (e) above.

($TR_{i,t} = TR \times \frac{CR_{i,t}}{CR20YR}$)

h) The new rate element for a Customer Segment is then based on the revenue requirement allocation to that segment for the Application Year, using the same rate design as before for that Customer Segment, as approved at the time of the regulatory reset.

The DSOAR do not define which historical period is to be used for determining the proportional revenue allocation. The ERC intends to use the 12-month period ending on December 31 before the Application Year for this purpose.

Implicit to this methodology is the fact that a new rate structure or Customer Segment cannot be introduced during a Regulatory Period. In addition, it is also a requirement of the DSOAR that existing rate designs cannot be amended during a Regulatory Period.

Such changes, or the introduction of a new rate structure can therefore only be made as part of the Regulatory Reset Process.

Changes in the rates, to account for new required revenue allocations to a Customer Segment, can therefore only be introduced by changing the quantum of those rate elements that already exist for each particular rate structure.

11.3 Side constraints

In terms of Clause 6.4 of the RDWR, all maximum wheeling rates (excluding the impact of the S-factor discussed in Section 10) are subject to side constraints, in terms of which the annual change in revenue that can be collected through a particular rate may not exceed certain predefined limits.

The ERC will determine the side constraint factor once all the information for the regulatory reset process has been received. This constraint will, however, not be less than 2%. (This figure is to be added to the weighted index for an Application Year to calculate the maximum allowed price-movement for a Regulatory Year.)

In terms of the RDWR, the ERC may decide to relax the side constraints in any particular year, should the restrictions prove to be so excessive that the integrity of the price-setting process could be compromised.

11.3.1 Impact of side constraints when adapting rates with varying structures

The ERC notes that the application of a single tariff measure, such as the cost per energy unit (kWh) promoted by the RDWR, can give rise to unintended results when applied to rate structures also incorporating demand components or substantial fixed components. As an example, the following can be considered.

- In theory, during a rate reset, all components of a rate structure will be adapted, generally by the same proportion. For a composite rate, this means that the unit rate, the demand rate and the fixed rate will be affected.
- Since the actual energy consumed (kWh) only is taken into account when testing whether side constraints have been breached, by applying the test as prescribed to the unit component of a rate the side constraints may not be breached.
- However, if the total account of a customer is considered (i.e. including the demand component and a fixed component) and that is converted to a single cost per kWh, the situation may be different. Customers with an improving load factor (i.e. those with demand rising relative to unit consumption), will find that their average cost per kWh is increasing relative to those with decreasing load factors.
- It is therefore possible that based on looking at unit consumption only but considering the total electricity cost for a customer, the side constraints may be exceeded for certain customers, even though the adoption of the rate in general fell within the side constraints.
- Such customers, when considering the impact of a new rate, may therefore consider that the side constraint has been breached and may file a complaint with the ERC.

The ERC does not view breaches of the side constraints in such situations as intentional or against the spirit of the RDWR. In assessing whether side constraints have been breached, it will consider the impact of a new rate on an “average” customer for a particular Customer Segment. This will be a customer for which the unit consumption, demand (and fixed rate, where appropriate) will be at the average level for that Customer Segment. Only if the side constraints are breached for such an “average” customer, will complaints be taken further.

The ERC expects Regulated Entities to conduct the same “average customer” test when adapting existing rates.

11.3.2 Inter-class cross-subsidies

In terms of RA 9136 (EPIRA IRR) Rule 16, Section 5, inter-class cross-subsidies in distribution rates are not allowed. It is therefore essential that Regulated Entities confirm in their rate filings that no such subsidies are known to exist in their proposed rate design.

11.4 Introducing new rate structures

As noted above, new rate structures can only be introduced during regulatory resets. Where such new rate structures are to be introduced, Regulated Entities must provide the ERC with detailed information about the definition of these intended new structures, those customers that are likely to be incorporated in the new Customer Segment, and the Segments from which they will be drawn.

In considering applications for new rate structures, the ERC will need to be convinced that the impact of these rates on existing customers who will fall into the new category will not be such that the side constraints are exceeded. Side constraints will remain in force for changes in rates between Regulatory Periods. Regulated Entities therefore have to provide evidence of the impact of the proposed new rate structure and typical consumption patterns on the total electricity cost for the average customer in the new Customer Segment. This has to be compared with the historical cost for such customers, in the categories from which they are likely to have been moved.

In terms of the DSOAR (Clause 5.3.4), during a regulatory reset, Regulated Entities have to conduct a cost of service study for each Regulated Distribution System. This study will functionalize the annual allowed revenue and allocate it to each Customer Segment. This will be compared against the charges that are likely to be paid by each Customer Segment based on the existing (and new) rate structures.

While it is recognized that rates have to be practical and inevitably require a degree of compromise, Regulated Entities have to ensure that as far as is practically possible, the actual cost for distribution wheeling as charged to each Customer Segment fairly reflects the cost to provide Regulated Distribution Services to that Customer Segment. In addition, the rate for each Customer Segment should also ensure that the contribution of an individual customer to the revenue base for that segment fairly reflects the average cost to provide the service to that customer.

11.5 Passed-through costs

In terms of the DSOAR, the cost of purchased power and transmission costs are to be considered as passed-through costs and shall not be included under distribution wheeling costs. They shall also not be taken into account in the calculation of the maximum average price-cap for Regulated Distribution Systems, or in determining whether side-constraints have been breached.

Force Majeure and Tax Change Event regulated pass-through amounts are likewise not to be considered as part of the maximum average price-cap for Regulated Distribution Systems.[73]

11.5.1 Recouping system losses

In terms of the proposed DSOAR (Clause 5.4), Regulated Entities are entitled to recover Distribution System losses through ERC approved System Loss Charges, subject to a System Loss Cap. This component is to be separately indicated in electricity invoices and will not be included as part of the maximum average price-cap for Regulated Distribution Systems.

Regulated Entities are responsible for procuring all energy related to Distribution System losses. Where such losses exceed the System Loss Cap (recently set at 8.5%, but subject to change by the ERC), this will be to the account of the Regulated Entities.

Electricity consumption incurred by a Regulated Entity in the course of providing Regulated Distribution Service, Distribution Connection Services or Regulated Retail Services will no longer be recovered as a pass-through cost from consumers. These costs will now be treated as an operating expense, as discussed in Section 4.1.2.

[73] See Section 12.1 for a further discussion on these aspects

12. OTHER ISSUES

In this Section, a number of diverse issues are discussed that are raised in the RDWR but have not been covered elsewhere in the Position Paper.

12.1 Regulated pass-through events

In Section 11.5 above, a number of cost items were identified as pass-through items as far as the wheeling rates are concerned. Of these, the regulated pass-through for Force Majeure Events and Tax Event Changes require further clarification.

12.1.1 Force Majeure Event pass through

The treatment of Force Majeure Event pass through is discussed in Article X of the RDWR. If a Force Majeure event occurs, a Regulated Entity may seek the ERC's approval to charge customers of the relevant Regulated Distribution System an additional amount. This amount, or the FM Pass Through Amount, is to allow a Regulated Entity to recover additional Regulated Distribution System related costs incurred as a result of the occurrence of a Force Majeure Event.

After consideration of a claim for a Force Majeure Event, the ERC may decide to approve it and will determine the additional amount that will be added to the maximum average price-cap for a Regulated Distribution System and the period over which this addition should occur. In such cases, the Regulated Entity must publish a notice informing customers of the approved FM Pass Through Amount, the circumstances giving rise to it and the manner in which it will be applied.

The procedure that a Regulated Entity has to follow in submitting an application to the ERC to seek approval for a FM Pass Through Amount is described in Clause 10.2 of the RDWR. This section also lists the supporting information that a Regulated Entity has to provide, as well as the constraints that will apply to such an amount. In addition, the process to be followed for any application involving an adjustment in rates is described in Section 12.3 below.

In considering whether to approve an application for a FM Pass Through Amount, the ERC has to consider a number of factors, as discussed in Clause 10.4 of the RDWR. Any approach that the ERC intends to pursue to determine whether an event should be excluded for the purpose of the performance incentive scheme (see Section 10.3.7) will also be taken into account in assessing Force Majeure Event Claims, although a Force Majeure Event will normally be more severe than even those events excluded in terms of the performance incentive schemes. Conversely, where a Force Majeure Event is accepted to have affected the service performance of Regulated Entities, this will automatically constitute an excluded event for the performance incentive scheme.

FM Pass Through amounts are not to be taken into account in the calculation of the maximum average price cap or in determining whether that price has been exceeded.

12.1.2 Tax Event Regulated pass through

Tax Event pass through is discussed in Article XI of the RDWR.

If a Positive Tax Change Event occurs during the Second Regulatory Period, a Regulated Entity may approach the ERC for approval to charge customers an additional amount over the maximum average price-cap. This amount, or the Positive Tax Pass Through Amount, is to allow a Regulated Entity to recover additional costs incurred as a result of the Tax Change Event.

Conversely, if a Negative Tax Change Event occurs during the Second Regulatory Period, the ERC may require a Regulated Entity to pass through a reduction to customers in the maximum average price-cap. This amount, or the Negative Tax Pass Through Amount, is to prevent over-recovery of taxes paid resulting from a Tax Change Event.

After considering claims for a Positive Tax Pass Through, the ERC will evaluate and decide whether to approve this and will determine the additional value that will be applied to the maximum average price-cap and the period over which this should occur. Alternatively, if the ERC decides to implement a Negative Tax Pass Through, it will determine the reduction to apply to the maximum average price-cap and the period over which this is to occur. The Regulated Entity must publish a notice informing customers of the approved Positive Tax Pass Through or required Negative Tax Pass Through Amount, the circumstances giving rise to it and the manner in which it will be applied.

The procedure that a Regulated Entity has to follow in seeking the ERC's approval for a Positive Tax Pass Through is described in Clause 11.2 of the RDWR. It also lists the supporting information that a Regulated Entity has to provide and the constraints that will apply to such an amount. The procedure the ERC will follow in deciding on a Negative Tax Pass Through is described in Clause 11.3 of the RDWR. In addition, the process to be followed for any application involving an adjustment in rates is described in Section 12.3 below.

In considering whether to approve an application for a Tax Pass Through and the extent of such a pass through, the ERC has to consider a number of factors. These are discussed in Clause 11.4 of the RDWR.

Tax Pass Through amounts are not to be taken into account in the calculation of the maximum average price cap or in determining whether that price has been exceeded.

12.2 Re-opening events

The RDWR allows for a number of events that will constitute re-opening events, as described in Article XII of the RDWR. These events are those that are substantial enough to warrant a recalculation of the maximum average price caps or the X-factor.

12.2.1 Increase in CPI

If the change in the CPI between two consecutive quarters is bigger than 0.07, a Regulated Entity may apply to the ERC for a change in the method used to calculate the maximum average annual price-cap (Clause 12.1 of the RDWR). The ERC will consider such an application and if it accepts that the situation has occurred, will determine a new price calculation method. This method will apply for the remaining period of the Regulatory Period.

This re-opening event will only arise during periods of hyper-inflation, under which circumstances the currently proposed price-setting methodology could result in unintended outcomes. It is therefore considered appropriate to reconsider the price-setting formula under such conditions.

12.2.2 Deferred capital expenditure

Substantial delays in significant capital expenditure as compared with the programs forecasted during the regulatory reset and approved by the ERC, will result in a Regulated Entity over-recovering revenue. To avoid this, allowance is made for the recalculation of the X-factor where such situations arise (Clause 12.2 of the RDWR).

If the capital expenditure on any Significant Project is deferred for longer than 18 months from the time it was forecasted to be undertaken, a Regulated Entity must notify the ERC. If following such notice, or through its own investigations, the ERC determines that such expenditure on a Significant Project has not occurred within 18 months of the time forecast, it will notify the Regulated Entity of its determination.

After taking into account submissions from the Regulated Entity, the ERC may recalculate the X-factor based on the exclusion of that capital expenditure. This recalculated X-factor will apply for the rest of the Regulatory Period.[74] Alternatively, during the Regulatory Reset for the Regulatory Period following the one in which a Significant Project has been deferred, the ERC may calculate the excess revenue that was earned by a Regulated Entity on the capital value of the deferred project and treat this as an over-recovery by the Regulated Entity, that will be recovered during the next Regulatory Period.

Excess revenue earned by a Regulated Entity as a result of delaying capital expenditure will be recovered as part of recalculating the X-factor or the over-recovery to be recovered during the next Regulatory Period. This will be based on calculating the excess revenue earned by a Regulated Entity over the period that a Significant Project was deferred. Such excess revenue arises as a Regulated Entity would have earned a return on capital that was, in the event, not invested, as well as depreciation of that capital.

This excess revenue will be determined based on the return on the deferred forecast capital expenditure, as well as the allowance made for regulatory depreciation on this capital expenditure, as stated in Clause 12.2.3 of the RDWR.

If the ERC decides to recalculate the X-factor, the excess revenue will be deducted from the allowed revenue requirements for the first of the remaining years of the Regulatory Period.

Alternatively, if the excess revenue is to be treated as an over-recovery, such over-recovery amount will be deducted from the allowed revenue requirement for the first Regulatory Year of the following Regulatory Period (ARR2011 as per Clause 4.15.2 of the RDWR). This form of recovery will also apply to any Significant Project that is deferred into the next Regulatory Period, even if a project is not deferred by 18 months or more. This

[74] Unless recalculated again in terms of events arising requiring such recalculation under Article XII.

implies that any Major Project deferred to a next Regulatory Period will be excluded from a Regulated Entity's construction program, unless it is re-applied for. Should the Regulated Entity wish to still proceed with the same Major Project during the next Regulatory Period, this project should be included in the forecasts for capital expenditure submitted by the Regulated Entity for the next Regulatory Period, in accordance with Section 5.2. Such a project will then be re-evaluated by the ERC and may be approved again for the next Regulatory Period.

12.2.3 Major un-forecasted acquisitions

If a Regulated Entity makes major un-forecasted acquisitions during the Second Regulatory Period, it may file an application to the ERC for a re-calculation of the X-factor. The process and the definition of major un-forecasted acquisitions are described in Clause 12.4 of the RDWR. It should be noted that under Commonwealth Act 146, Regulated Entities must obtain prior approval for any major capital works prior to commencing with such works. Even if it therefore decides to not file for a re-opening event as a result of an unforeseen project, a Regulated Entity is still obliged to notify the ERC of its intention to proceed with this project.

This allowance makes provision for the acquisition of new assets not foreseen at the time of submitting the capital expenditure forecasts, or for the case where the actual value of assets acquired exceed 150% (or is less than 60 %) of the forecast value approved by the ERC for a single asset or the cumulative total of assets acquired during the Third Regulatory Period.

If, after investigation, the ERC determines that the circumstances claimed by a Regulated Entity have occurred, the X-value for the remainder of the Second Regulatory Period will be recalculated. Provision is also made for the ERC to instigate a recalculation of the X-factor if the actual value of assets acquired by a Regulated Entity is less than 60% of the approved forecast.

The RDWR defines major acquisitions not included in the capital expenditure forecasts, as being more than the lesser of PhP150 million or 3% of the value of the total assets in use on a Regulated Distribution System at the time of the acquisition.

Further decisions on the level of materiality may be taken once the ERC has received the details of historical capital expenditure on Regulated Distribution Systems as discussed in Section 5.2.7, including the materiality levels described in Clause 12.4.1(d)ii of the RDWR.

Where un-forecasted assets are required that do not meet the materiality criterion set out above but would still be considered a major project in terms of the RDWR, prior approval for such projects must be obtained from the ERC in terms of Commonwealth Act 146. Such acquisitions will not result in a re-opening event of additional earnings by a Regulated Entity during a current Regulatory Period. However, if deemed efficient at the time of the valuation, these assets will be included in the Regulatory Asset Base from the next Regulatory Period onwards.

12.2.4 Change in a major capital project

The ERC recognizes that situations may arise where the need for a major capital project originally planned by a Regulated Entity and approved by the ERC, may change or disappear during the course of a Regulatory Period. At the same time, a need for another major capital project (which could be related or non-related to the original project) could arise.

In these situations, Regulated Entities can submit a request to the ERC to substitute an originally approved capital project with an altered version of the same project, or with a new project. As long as the value of the altered or new capital project does not exceed that approved by the ERC for the original project, the ERC will consider such requests. This consideration will be based on the following factors:

- the reasons why the factors supporting the original capital project requests have changed or disappeared;
- the reasons why the need for a changed or new capital project (or projects) have arisen;
- the reasonableness and suitability of the proposed project to meet the changed or new need for the work, including a review of alternative project options considered by the Regulated Entity; and
- the reasonableness of the cost estimates and construction timelines submitted for the proposed changed or new capital project.

Regulated Entities are required to provide sufficient supporting information with their altered project requests to allow the ERC to effectively conduct this analysis. In the absence of sufficient information, requests will be rejected.

Should the ERC, based on its consideration, decide that the request by a Regulated Entity is reasonable, it will grant approval for the altered or new capital project to be implemented. In such a case:

- the capital expenditure for the altered or new capital project may be approved as requested by the Regulated Entity, or could be adjusted based on the analysis conducted by the ERC;
- the extent of deferred capital expenditure that will be recovered due to the delay of the originally approved major project (Section 12.2.2) will be limited to the difference between the original approved project value and the approved value of the altered or new capital project;
- approval of an altered or new capital project will not be considered as grounds for a re-opening event (Section 12.2.3); and
- the new assets created may still be subject to optimization at the next Regulatory Reset, should this be required in terms of the optimization principles contained in the Valuation Handbook.

Construction on a new or altered capital project may only proceed after approval by the ERC.

12.2.5 Changes in other capital expenditure

It is similarly recognized by the ERC that capital expenditure on other (non major) capital projects may be required to change from that originally submitted to and approved by the ERC during the Regulatory Reset.

Such events do not necessitate notification to or approval by the ERC, and are not considered sufficient grounds for a re-opening event.[75] However, any assets created during a Regulatory Period will be subject to optimization (in terms of the Valuation Handbook) at the next Regulatory Reset, prior to inclusion in the Regulatory Asset Base.

12.2.6 Excessive unforeseen Operating and Maintenance expenditure

If a Regulated Entity has to incur unforeseen operating and maintenance expenditure to the extent that the total expenditure on this building block exceeds 125% of that allowed by the ERC for any Regulatory Year of the Second Regulatory Period, a re-opening event may arise. In addition, expenditure on approved operating and maintenance items that result in the total expenditure on this building block exceeding 125%, or falling below 75%, of the amount approved by the ERC for any Regulatory Year of the Second Regulatory Period, may also result in a re-opening event.

The procedure for identifying and managing such a re-opening event is described in Section 12.7 of the RDWR.

12.2.7 Major change in consumption patterns

Changes in electricity consumption patterns that lead to actual consumption over a test year varying by more than 15% from the predicted value accepted by the ERC for that year will give rise to a re-opening event. The procedure for calculating this variance is described in Section 12.3 of the RDWR.

12.2.8 Major changes to the WACC

It is recognized that the regulatory WACC is subject to considerable volatility and that material changes to this parameter may occur between various Regulatory Resets for Entry Groups into PBR. If, at a subsequent Regulatory Reset for a new Entry Group, the newly calculated WACC (for that Entry Group) varies by more than 10% of that used for a previous Entry Group, this will give rise to a re-opening event. This is to ensure that Regulated Entities earn a return on investments that is commensurate with the investment risk, and also to ensure an equitable situation between Regulated Entities entering PBR at different dates.

12.3 Procedure for events leading to an adjustment in rates

As noted before, pertinent Supreme Court Decisions have made it clear that Section 4(e), Rule 3 of the Implementing Rules and Regulations (IRR) of R.A. 9136 should be strictly

[75] By implication, this means that a Regulated Entity will not necessarily earn a return on additional minor capital works before the next Regulatory Period. However, this downside could be offset by the ability of a Regulated Entity to defer approved minor capital works.

adhered to in all applications filed with the Commission for rates and other relief affecting consumers. Any application under the RDWR that would lead to revenue recovery on the part of Regulated Entities and therefore give rise to an adjustment in rates for consumers (which could be an increase or decrease), including applications for applying pass-through costs and re-opening events for recalculating the X-factor, should comply with Section 4(e), Rule 3 of the IRR.

In this light, the following procedure will be applied to any applications filed by Regulated Entities that may give rise to rate adjustments for consumers.

a) Filings by Regulated Entities of applications for recovery should be made within the times prescribed in the RDWR and in compliance with the pre-filing requirements set forth in Section 4(e), Rule 3 of the IRR of R.A. 9136.

b) The ERC shall set a date for the public hearing of such filings not later than thirty (30) days after receipt of the filing.

c) All memorandums, comments, position papers on the application, together with all supporting documentation and testimonial evidences in affidavit form associated with the public hearing shall be submitted within a period of one month from the date of the hearing.

d) A final resolution on the application for recovery shall be given not later than six months from the filing of the application.

12.4 Related party transactions

A Regulated Entity may in the course of its management of a Regulated Distribution System enter into transactions with external, but related parties to procure operating or maintenance support, goods or materials.[76] The definition of related parties is as per International Accounting Standard (IAS) 24, and is summarized in Appendix A. Parties are considered to be related if one party has 50% or more of the shareholding in the other, or the ability to control the other party or to exercise significant influence or joint control over the other party in making financial and operating decisions. [77]

The ERC does not wish to discourage such transactions with related parties. However, it wishes to ensure that an arms-length relationship between Regulated Entities and related parties are maintained. In addition, any dividends, profits or other benefits incurring to a Regulated Entity in terms of its association with a related party should ultimately become part of the revenue earned by Regulated Entities and will be taken into account when assessing the actual revenue that was earned in each Regulatory Year.

[76] For the avoidance of any doubt, such support refer to services or goods rendered for the effective management of the Regulated Distribution System, as defined in Section 4.1.1, and can also include activities not directly related to the operation or maintenance of the distribution network, for example general management or information system support.

[77] Such transactions may of course also be undertaken with completely independent parties. However, since Regulated Entities are not expected to share in any profits or other benefits derived by independent parties, the ERC does not require the same level of information on these transactions.

Where such transactions with related parties are foreseen during the Second Regulatory Period, sufficient details must therefore be provided by Regulated Entities as part of the Regulatory Reset Process when submitting expenditure forecasts, to allow the ERC to assess the reasonableness and efficiency of such transactions and to take into account the revenue or other material benefits that is expected to be earned through the relationship. These details shall include information about:

- the identity of each related party with whom the contracts will be entered into;
- the nature of the relationship between the Regulated Entity and the related party, including an indication of the shareholding or interest that the Regulated Entity has in the related party;
- a detailed description of the goods or services to be provided by each related party to the Regulated Entity in the course of the transactions, for each Regulatory Year;
- the justification of why the transaction is preferred with a related party rather than a fully independent party;
- the anticipated unit price, quantity, revenue and expenditure amounts of each of the related party transactions, in nominal PhP terms for each Regulatory Year;
- the anticipated revenue or other material benefits that will be earned from the Regulated Entity's interest in the related party, for each Regulatory Year; and
- any debts arising from related party transactions that will be forgiven or written off.

If the ERC determines that any related party transaction is likely to be less efficient than the similar transaction would have been with an independent party, or if the transaction was concluded using internal resources that are reasonably available, such transaction will not be allowed as part of the approved expenditure for the building block calculations.

In order to maintain a sufficient level of comfort about related party transactions and to ensure that such transactions are efficient, the ERC may conduct post-transaction audits on any related party transaction conducted by a Regulated Entity. These audits will focus on:

- the accuracy of the information provided to the ERC about the transaction including, where relevant, a verification of the actual information as compared with information submitted about the transaction as part of the Regulated Entity's expenditure forecasts;
- the efficiency of the transactions, relative to similar transactions with non-related parties;
- the extent to which an effective arms-length relationship had been maintained with related parties;
- the extent to which profits or benefits arising from a related party transaction has accrued back to a Regulated Entity or its officers; and
- any evidence that the transaction may have been used by a Regulated Entity to avoid obligations in terms of the RDWR.

If the findings from such an audit should raise concerns with regard to any of these aspects, further steps will be taken by the ERC after consultation with the Regulated Entity. Such steps may include a deduction of any excess benefits or revenue deemed to arise from the transaction, including the quantified value of the perceived inefficiency of such transactions, from the Regulated Entity's allowed revenue for the next regulatory period, using the correction factor described in Clauses 4.2.1 and 5.2 of the RDWR for this purpose. Alternatively, such benefits or revenue may be deducted from the Net Efficiency Adjustment described in Clause 9.2 of the RDWR.

12.5 Excluded services

The RDWR allows for certain Excluded Services that may be provided by a Regulated Entity, but that do constitute Regulated Distribution Services and for which the wheeling rates will not apply. Excluded Services are deemed to be those services provided in respect of a Regulated Distribution System by a Regulated Entity in its Qualified Franchise Area that is not a Regulated Distribution Service and also not a contestable service. The services included under the RDWR, for which the maximum average price-caps will apply, are discussed in Section 1.3.

The prime example of an Excluded Service will be Distribution Connection Services, as envisaged under the DSOAR. At present, these services are included as Regulated Distribution Services under the RDWR, as are the operating, maintenance and capital expenditure associated with the Distribution Connection Services and the asset base (Distribution Connection Assets).

However, following the full implementation of the DSOAR, these Distribution Connection Services will be excluded from the Regulated Distribution Services, as will be the associated expenses and asset base. The RDWR and this Issues Paper should therefore be read against that background and with that likelihood in mind. If Distribution Connection Services and the associated expenses and assets are separated from the Regulated Distribution Services and the regulated asset base, it will not constitute a contradiction with the RDWR or this Issues Paper.

It should be noted that in terms of the DSOAR, energy meters do not form part of Distribution Connection Assets and these will therefore remain part of the regulated asset base under the RDWR, even if Distribution Connections are separated out.

12.6 Subtransmission Assets

In terms of Section 8 of the EPIRA and Rule 22, Section 13(b) of its IRR, it is contemplated that Subtransmission Assets will be transferred from TransCo or NGCP to Regulated Entities. Where such Transferred Subtransmission Assets exist at the start of the Third Regulatory Period, they will be operated as part of the Regulated Distribution System and thus form part of the Regulatory Asset Base on which the distribution wheeling rates will be based.

The manner in which Transferred Subtransmission Assets are valued differs from that for the rest of the Regulated Distribution System and is described in Clause 4.8.13 of the RDWR. Depreciation on these assets is also calculated differently and is explained in Clause 4.10.1(b) of the RDWR.

It should be noted that Subtransmission Assets are defined[78] as only those assets used by Distribution Utilities as intermediate facilities to connect transmission and distribution substations. Assets used to connect End Users directly to the transmission network or to transmission or distribution substations are considered to be Connection Assets and, for purposes of this Position Paper, will be treated similarly to other Distribution Connection Assets.

To avoid material distortion in the calculation of the maximum annual price allowed to a Regulated Entity for the Second Regulatory Period, the electricity consumption of End Users connected to such Transferred Subtransmission Assets will not be included in the total electricity consumption figures for a Regulated Entity on which the price-control arrangements for that Regulatory Entity is based[79], unless a utility can demonstrate to the satisfaction of the ERC that such distortion will not arise. The proportional use of such customers of the overall Distribution System of a Regulated Entity will be reflected in specific connection agreements with these customers.

12.7 Avoiding differences in the WACC between Regulated Entities

A new regulatory WACC will be determined for each Entry Point into the Third Regulatory Period. A mechanism exists (see Section 12.2.8) to ensure that substantial changes in the WACC between Entry Points will be passed on to previous entrants as a re-opening event. However, a situation could still arise that at the end of a Regulatory Period, the effective WACC that applied to Regulated Entities entering PBR at different Entry Points will be different. This would typically be the case where changes occurred in the WACC that were not sufficient to trigger a re-opening event.

To ensure equity between Regulated Entities, the ERC will at the start of the Third (and subsequent) Regulatory Period for each Entry Group, calculate the effective WACC that applied to that Entry Group over the Third (or subsequent) Regulatory Period. It will also calculate the equivalent WACC that should have applied over the Third Regulatory Period for that Entry Group, had the actual WACC as determined at various Entry Points been used. These calculations will take into account that dates at which new WACC values were calculated and the periods that these values would have applied to an Entry Group. The WACC between entry points will be assumed to be constant, and the resulting equivalent WACC calculation will be weighted according to the duration that values derived at each reset would have applied (and not according to the actual capital investment programs of a Regulated Entity).

The difference between the actual return on capital earned by a Regulated Entity over the Third Regulatory Period, and the value which would have resulted had the newly derived equivalent WACC Period applied for the Third Regulatory Period, will be calculated. This

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[78] See DSOAR, Clause 1.2

[79] Experience has shown that the inclusion of such consumption can lead to a low indicative MAP. However, once this is translated into distribution tariffs which take into account a representative asset allocation between consumer groups, smaller, low-voltage consumers often experience very substantial increases in their actual rates – far beyond that indicated in the average price (MAP). This distortion makes it difficult to assess in advance the implication of price-control decisions.

difference, unadjusted for the time value of money, will be added to or subtracted from the allowed revenue requirement for that Regulated Entity for the Fourth Regulatory Period.

Pasig City, December 1, 2009.

ZENAIDA G. CRUZ-DUCUT
Chairperson

ALEJANDRO Z. BARIN
Commissioner

RAUF A. TAN
Commissioner

MARIA TERESA A.R. CASTAÑEDA
Commissioner

JOSE C. REYES
Commissioner

APPENDIX A: RELATED PARTY TRANSACTIONS

Related party transactions and the obligation of disclosure by Regulated Entities of such transactions are described in Section 12.34 of the Position Paper.

In this section, the definition of related parties and transactions that would constitute related party transactions are defined. These definitions are taken from the International Accounting Standards IAS 24.

A1. Definition of related parties

Parties are considered to be related if one party has the ability to control the other party or to exercise significant influence or joint control over the other party in making financial and operating decisions.

Clause 24.9 [of IAS 24] states that a party is related to an entity if:

(a) directly, or indirectly through one or more intermediaries, the party:

- (i) controls, is controlled by, or is under common control with, the entity (this includes parents, subsidiaries and fellow subsidiaries);
- (ii) has an interest in the entity that gives it significant influence over the entity; or
- (iii) has joint control over the entity;

(b) the party is an associate (as defined in IAS 28) of the entity;

(c) the party is a joint venture in which the entity is a venturer;

(d) the party is a member of the key management personnel of the entity or its parent;

(e) the party is a close member of the family of any individual referred to in (a) or (d);

(f) the party is an entity that is controlled, jointly controlled or significantly influenced by or for which significant voting power in such entity resides with, directly or indirectly, any individual referred to in (d) or (e); or

(g) the party is a post-employment benefit plan for the benefit of employees of the entity, or of any entity that is a related party of the entity.

Per Clause 24.11 [of IAS 24], the following are not considered related parties:

- two enterprises simply because they have a director or key manager in common;
- two venturers simply because they share joint control over a joint venture;
- providers of finance, trade unions, public utilities, government departments and agencies in the course of their normal dealings with an enterprise; and
- a single customer, supplier, franchiser, distributor, or general agent with whom an enterprise transacts a significant volume of business merely by virtue of the resulting economic dependence arising between the parties.

A2. Definition of related party transactions

IAS 24.9 states that a related party transaction is a transfer of resources, services, or obligations between related parties, regardless of whether a price is charged.

Typical services that would be included under related party transactions are:

- Providing or receiving services;
- Purchase or sales of goods, property and other assets;
- Leases;
- Transfers of research and development;
- Transfers under license agreements;
- Transfers under finance arrangements (including loans and equity contributions in cash or in kind);
- Provision of guarantees or collateral; and
- Settlement of liabilities on behalf of the entity or by the entity on behalf of another party.

APPENDIX B: EXPLANATION OF O&M COST CATEGORIES

The description of the various operating and maintenance expenditure categories are generally aligned with the UFR descriptions as indicated below. Where necessary, certain changes have been made as also indicated below.

414-000-00 REGULATED DISTRIBUTION SERVICES EXPENSES

414-000-10 Operations supervision and engineering

> This account represents the expenses incurred in the general supervision and direction of the operation of the distribution system.
>
> Direct supervision of specific activities, such as station operation, line operation, meter department operation, etc. shall be charged to the appropriate account.
>
> Included in this account are salaries and wages in: performing special tests to determine efficiency of equipment operation, preparing or reviewing budgets, estimates and drawings relating to the distribution operation, preparing instructions for operating activities, formulating and reviewing work of the department, and secretarial work for supervisory personnel but not general clerical work; and other expenses related to the activities described above.

414-580-10 Operation - Contractor services

> This account should reflect all operating expenditure incurred by a Regulated Entity for contracting in external support or services (whether from an independent outside contractor or a related party) to assist with the operation of the Regulated Distribution Network. This would include the cost of specialists engaged specifically to oversee or advise on network operating practices at the Regulated Entity.

414-581-10 Operation – Load Dispatching

> This account represents the expenses incurred in load dispatch operations pertaining to the distribution of electricity.
>
> Included in this account are salaries and wages of employees in: directing and switching, arranging and controlling clearances for construction, maintenance, test and emergency purposes, controlling system voltages, preparing operating reports, and obtaining reports on the weather and special events; and expenses incurred for: communication service provided for system control purposes, system record and report forms, and meals, traveling and incidental expenses.

414- -10 Operation – Structures

> This account should include all the operating expenses incurred in the operation of structures making up part of the Regulated Distribution Network, that are not covered under the expense categories listed below.

414-582-10 Operation – Substation Expenses

> This account represents the expenses incurred in the operation of distribution substations.
>
> Included in this account are salaries and wages in supervising station operation, adjusting station equipment where such adjustment primarily affects performance such as regulating

the flow of cooling water, adjusting current fields of a machine, changing voltage of regulators or changing station transformer taps, keeping station, log and records and preparing reports on station operation, inspecting, testing and calibrating station equipment for the purpose of checking its performance, operating switching and other station equipment, standing watch, guarding and patrolling station and station yard, sweeping, mopping and tidying station, and care of grounds, including cutting grass, etc.; and materials and expenses incurred for: building service, operating supplies such as lubricants, commutator brushes, water and rubber goods, station meter and instrument supplies such as ink and charts, tools, transportation, and meals, traveling and incidental expenses.

414-583-10 Operation – Overhead lines and devices

This account represents the expenses incurred in the operation of distribution lines and associated devices.

Included in this account are salaries and wages in supervising line operation, changing pole-mounted distribution transformer taps, inspecting and testing lighting arresters, line circuit breakers, switches and grounds, inspecting and testing pole-mounted distribution transformers for the purpose of determining load, temperature or operating performance, routine patrolling of lines, load test and voltage surveys of feeders, circuits and pole-mounted distribution transformers, removing pole-mounted distribution transformers, oil circuit reclosers and sectionalizers with or without replacement, installing pole-mounted distribution transformers, oil circuit reclosers or sectionalizers with or without change in capacity provided that the cost of first installation of these items is capitalized, voltage surveys, either routine or upon request of consumers, including voltage tests at consumer's main switch, transferring loads, switching and reconnecting circuits and equipment, electrolysis surveys, and inspecting and adjusting line testing equipment; and materials and expenses for: tools, transportation, meals, traveling and incidental expenses, and operating supplies such as instrument chart, rubber goods, etc..

414-584-10 Operation – Underground cables and devices

This account represents the expenses incurred in the operation of underground distribution circuits and associated devices.

Included in this account are salaries and wages in supervising cable operation, changing surface-installed distribution transformer taps, inspecting and testing lighting arresters, circuit breakers, switches and grounds, inspecting and testing surface-installed distribution transformer for the purpose of determining load, temperature or operating performance, routine testing of cable circuits, operating cable cooling systems, load test and voltage surveys of feeders, circuits and surface-installed distribution transformer, removing surface-installed distribution transformer, oil circuit reclosers and sectionalizers with or without replacement, installing surface-installed distribution transformer, oil circuit reclosers or sectionalizers with or without change in capacity provided that the cost of first installation of these items is capitalized, voltage surveys, either routine or upon request of consumers, including voltage tests at consumer's main switch, transferring loads, switching and reconnecting circuits and equipment, electrolysis surveys, and inspecting and adjusting line testing equipment; and materials and expenses for: tools, transportation, meals, traveling and incidental expenses, and operating supplies such as instrument chart, rubber goods, etc..

414-585-10 Operation – Street Lighting and Signal System

This account represents expenses incurred in the operation of street lighting and signal systems plant which is owned or leased by the distribution utility and those owned by customers where such work is done regularly as a part of the street lighting and signal system service.

Included in this account are salaries and wages in: supervising street lighting and signal systems operation, replacing lamps and incidental cleaning of glassware and fixtures in connection therewith, routine patrolling for lamps outages, extraneous nuisance or encroachments, etc., testing lines and equipment including voltage and current measurement, and winding and inspecting time switches and other controls; and materials and expenses for: street lamp renewals, transportation and tools, and meals, traveling and incidental expenses.

414-586-10 Operation – Meter Expenses

This account represents expenses incurred in the operation of distribution network meters and associated equipment (not consumer meters).

414-587-10 Operation – Rents

This account represents rent expenses on property of others used, occupied or operated in connection with the distribution system, joint use of poles and payments to the government and others for the use and occupancy of public lands and reservations for distribution line rights of way.

This account includes rentals of property of others used in connection with the distribution system.

414-588-10 Information technology (distribution network related)

Distribution IT systems are dedicated systems directly supporting the efficient operation and maintenance of Distribution Networks. This would include the hardware and software used for applications such as geographic information systems, asset databases, fault monitoring and recording, SCADA and network performance data recording.

414-589-10 Operation – Miscellaneous Expenses

This account represents other expenses incurred in distribution system operation not classifiable in the specific accounts described above.

This account includes salaries and wages in: general records of physical characteristics of lines and substations, such as capacities, etc., ground resistance records, joint pole maps and records, distribution system voltage and load records, preparing maps and prints, service interruption and trouble records and general clerical and stenographic work; and expenses incurred in: operating records covering poles, transformers, manholes cables and other distribution facilities, and janitorial work at distribution office buildings including cutting grass, etc.; and materials and expenses incurred for: communication service, building service, miscellaneous office supplies, printing and stationeries, maps and records and first-aid supplies, and research, development and demonstration.

414-000-20 Maintenance

The maintenance accounts described below are to be used when the primary purpose of the activity is preventing failure, restoring service, and/or maintaining plant life at its original quality of service.

414-590-20 Maintenance – Supervision and Engineering

This account represents expenses incurred in the general supervision and direction of maintenance of the distribution system.

This account includes salaries and wages related in: special tests to determine efficiency of equipment operation, preparing and reviewing budgets, estimates and drawings related to maintenance activities, preparing instructions for maintenance activities, formulating and reviewing routine maintenance activities, and secretarial work for supervisory personnel but not general clerical work chargeable to other accounts; and other expenses related to the activities described above, such as: operating records covering poles, transformers, manholes cables and other distribution facilities, and janitorial work at distribution office buildings including cutting grass, etc..

414-591-20 Maintenance - Contractor services

This account should reflect all maintenance-related expenditure incurred by a Regulated Entity for contracting in external support or services (whether from an independent outside contractor or a related party) to assist with the maintenance of the Regulated Distribution Network. This would also include the cost of specialists engaged specifically to inspect, oversee or advise on network maintenance practices at the Regulated Entity.

414-592-20 Maintenance – Structures

This account should include all the operating expenses incurred in the maintenance of structures making up part of the Regulated Distribution Network, that are not covered under the expense categories listed below.

414-593-20 Maintenance – Substation Equipment

This account represents expenses incurred in maintenance of plant, the book cost of which may be included in the sub-accounts Stations and Equipment and Storage Battery Equipment under the classification Distribution Plant.

Included in this account are salaries and wages of employees; materials and other expenses in connection with the maintenance of structures as described in the above paragraph; direct field supervision; inspecting, testing and reporting on condition of structures specifically to determine the need for repairs, replacements, rearrangements and changes and inspecting the adequacy of repairs which have been made; work performed specifically for preventing failure, restoring service and/or maintaining the life of the structures; repairing for reuse, materials recovered from the plant; testing for locating and clearing trouble; and replacing or adding minor items of plant which do not constitute retirement unit.

414-594-20 Maintenance – Overhead Lines and associated structures

This account represents expenses incurred in the maintenance of line distribution facilities and associated structures, the book cost of which may be included in the sub-accounts

Poles, Towers and Fixtures, Overhead Conductors and Devices and Services under the classification Distribution Plant.

Included in this account are salaries and wages, materials used and expenses incurred on poles, towers and fixtures in: installing additional clamps or removing clamps or strain insulators on guys in place, moving line or guy pole in relocation of pole or section of line, painting poles, towers, crossarms or pole extension, readjusting and changing position of guys or braces, realigning and straightening poles, crossarms, braces, pins, racks, brackets and other fixtures on poles, reconditioning reclaimed pole fixtures, relocating crossarms, racks, brackets and other fixtures on poles, repairing pole supported flatform, repairs by others to jointly owned poles, shaving, cutting rot or treating poles or crossarms in use or salvaged for reuse, stubbing poles already in service, supporting conductors, transformers and other fixtures and transferring them to new poles during pole replacements, and maintaining pole signs, stencils, tags, etc.; salaries and wages, materials used and expenses incurred on overhead conductors and devises in: overhauling and repairing line cutouts, line switches, line breakers and capacitor installations, cleaning insulators and bushings, refusing line cutouts, repairing line oil circuit breakers and associated relays and control wiring, repairing grounds, resagging, retying or rearranging position or spacing of conductors, standing by phones, responding to calls, cutting faulty lines, clear or similar activities at times of emergency, sampling, testing, changing, purifying and replenishing insulating oil, transferring loads, switching and reconnecting circuits and equipment for maintenance purposes, repairing line testing equipment, trimming trees and clearing bush, and chemical treatment of right of way area when occurring subsequent to construction of line; and salaries and wages, materials and expenses incurred on overhead services in: moving position of service either on pole or on consumer's premises, pulling shack in service wire, retyping service line, and refastening or tightening service bracket.

414-595-20 Underground cables & devices

This account represents the expenses incurred in the maintenance of underground distribution circuits and associated devices.

Included in this account are salaries and wages, materials used and expenses incurred on the same range of activities as described for maintaining overhead lines and associated structures, but where these activities relate to underground distribution circuits and associated devices.

414-596-20 Maintenance – Distribution Transformers

This account represents expenses incurred in maintenance of distribution line transformers (pole- or surface-mounted), the book cost of which may be included in the sub-account Line Transformers under the classification Distribution Plant.

Included in this account are direct supervision; inspecting, testing and reporting on condition of line transformers specifically to determine the need for repairs, replacements, rearrangements and changes and inspecting the adequacy of repairs which have been made; work performed specifically for preventing failure, restoring service and/or maintaining the life of the line transformers; repairing for reuse materials recovered from the plant; testing for locating and clearing trouble; replacing or adding minor items of plant which do not constitute a retirement unit; and materials and other expenses in connection with the maintenance of line transformers as described in the above paragraph.

414-597-20 Maintenance – Street Lighting and Signal Systems

This account represents cost of labor, materials used and expenses incurred in maintenance of plant, the book cost of which may be included in sub-account Street Lighting and Signal Systems under the classification Distribution Plant.

Included in this account are direct field supervision; inspecting, testing and reporting on condition of street lighting and signal systems specifically to determine the need for repairs, replacements, rearrangements and changes and inspecting the adequacy of repairs which have been made; work performed specifically for preventing failure, restoring service and/or maintaining the life of the street lights and signal systems; repairing for reuse materials recovered from the plant; testing for locating and clearing trouble; replacing or adding minor items of plant which do not constitute a retirement unit; and materials and other expenses in connection with the maintenance of street lights and signal systems as described in the above paragraph.

414-598-20 Information technology (distribution network related)

Distribution IT systems are dedicated systems directly supporting the efficient operation and maintenance of Distribution Networks. This would include the hardware and software used for applications such as geographic information systems, asset databases, fault monitoring and recording, SCADA and network performance data recording.

414-599-20 Maintenance – Meters

This account represents expenses incurred in the maintenance of Distribution System meters and associated installations, and meter testing equipment.

414-560-20 Maintenance – Miscellaneous Plant

This account represents expenses incurred in the maintenance of miscellaneous plant, the book cost of which may be included in the accounts Installations in Customer's Premises and Leased Property on Customer's Premises.

Included in this account are expenses of similar nature to that listed in other distribution accounts; and expenses in maintenance of office furniture and equipment used by distribution system department.

430-000-30 ADMINISTRATIVE AND GENERAL EXPENSES

430-920-30 Company management costs

This account should represent those costs associated with the compensation and operation of the board, senior management or other high-level governance or management bodies of a Regulated Entity. Included under this account should be the cost for management contracts, where some or all of the senior management functions of a Regulated Entity are outsourced to external parties (independent or related).

430-921-30 Administrative and General Salaries

This account represents the compensation of officers, executives and other employees of the utility properly chargeable to utility operating and not directly to any particular operating function. Included in this account is the amount of salaries and wages incurred and due.

430-922-30 Office Supplies and Expenses

This account represents expenses incurred for office supplies and expenses incurred in connection with the general administration of utility's operations which are assignable to specific administrative or general departments and are not specifically provided for in other accounts described herein.

Included in this account are automobile service, bank messenger and service charges, books, periodicals, bulletins and subscriptions to newspapers, newsletters, tax services, etc., building service expenses for consumer accounts, sales and administrative and general purposes, communication service expenses, cost of individual items of office equipment used by general departments which are of small value or short life, office supplies, payment of court costs, witness fees and other expenses of legal department, and postage, printing and stationeries.

430-923-30 Information technology (admin & general)

Administrative and general IT systems are those that contribute to the overall management and benefit of a Regulated Distribution System, but are not directly used in the operation of Distribution Systems. Such IT systems would for example include the hardware and software for accounting, payroll or human resource management.

430-924-30 Outside Services Employed

This account represents fees and expenses of professional consultants and others for general services which are not applicable to a particular operating function or to other accounts. It also represents the pay and expenses of persons engaged for a special or temporary administrative or general purpose in circumstances where the person so engaged is not considered as an employee.

Included in this account are fees, pay and expenses of accountants and auditors, actuaries, appraisers, attorneys, engineering consultants, management consultants, negotiators, public relations counsel, tax consultants, etc.; and supervision fees and expenses paid under contracts for general management services. It should be noted that this does not include payment for management contracts relating to senior company management activities.

430-925-30 Property Insurance

This account represents cost of insurance, labor and related supplies and expenses incurred for the protection against losses and damages to owned or leased property used in the operating.

Included in this account are premiums payable to insurance companies for fire, storm, burglary, explosions, lightning, fidelity, riot and similar insurance; special costs incurred in procuring insurance; insurance counsel, brokerage fees and expenses; and insurance inspection service. Reductions in this account are recoveries from insurance companies or others for property damages.

430-926-30 Injuries and Damages

This account represents cost of insurance or reserve accruals against injuries and damages claims of employees or others, losses of such character not covered by insurance and expenses incurred in settlement of injuries and damages claims, and expenses incurred in injuries and damages activities.

Included in this account are insurance premiums incurred for protection against claims from injuries and damages by employees or others, such as a public liability, property damages, casualties, employee disability, etc.; losses not covered by insurance on account of injuries or deaths to employees or others and damages to the property of others; fees and expenses of claim investigators; payment of awards to claimants for court costs and attorney's services; medical and hospital service and expenses for employees as a result of occupational injuries or resulting from claims of others; compensation payments under workmen's compensation laws; compensation paid while incapacitated as a result of occupational injuries; and cost of safety, accident prevention and similar educational activities. Reductions in this account are the reimbursements from insurance companies or others for expenses charged hereto on account of injuries and damages and insurance dividends or refunds.

430-927-30 Employee Pension and Benefits

This represents pensions paid to or on behalf of retired employees, or accruals to provide for pension, payments for employee accident, sickness, hospital and death benefits or insurance therefore.

Included in this account are payment of pensions under a non-accrual or non-funded basis; accruals for or payments to pension funds or to insurance companies for pension purposes; group and life insurance premiums; payment for medical and hospital services and expenses of employees when not a result of occupational injuries; payments of accident, sickness, hospital and death benefits or insurance; payments to employees incapacitated for service or on leave of absence beyond periods normally allowed, when not a result of occupational injuries or in excess of statutory awards; membership fees and dues in trade, technical and professional associations paid by a utility for employees; and expenses in connection with educational and recreational activities for the benefit of employees.

430-928-30 Franchise Requirements and Regulatory Commission Expenses

(For the Position Paper and the RDWR, this is now titled "Regulatory liaison and compliance").

This account represents expenses in connection with franchise, ordinance or similar requirements, provided that charges to this account are based at regular tariff rates. In addition, this account covers all regulatory liaison and regulatory compliance costs, including any contributions that Regulated Entities have to make towards the cost for the appointment of Regulatory Reset Experts by the ERC. This account also include expenses incurred in connection with formal cases before regulatory bodies or cases in which such body is a party, including payments made to a regulatory commission for fees assessed against the Utility for pay and expenses of such commission, its officers, agents and employees.

Included in this account are expenses for materials, supplies and services furnished government authorities without reimbursement in compliance with franchise or ordinance; fees and expenses of counsel, attorneys, accountants, engineers, clerks, attendants, witnesses and others engaged in the prosecution of or defense against petitioners or complaints presented to regulatory bodies, or in the evaluation of property owned or used in connection with such cases; and office supplies and expenses, payments to public service or other regulatory commissions, stationeries and printing, traveling expenses and other expenses incurred directly in connection with formal cases before regulatory commissions.

430-929-30 Rents

This account represents expenses for the property of others used, occupied or operated in connection with the consumer accounts, consumer service and informational sales and general and administrative functions of the utility.

Included in this account are rent expenses incurred.

430-930-30 Maintenance of Office and General Plant

This account represents expenses allocable or assignable to customer accounts, sales and administrative and general functions incurred in the maintenance of property being used in the utility operation.

Included in this account are expenses on labor, materials and other costs incurred.

430-931-30 Officers Allowances and Benefits

This account represents allowances and benefits given to the members of the Board of Directors, general manager, management assistants and other officers of the utility. It also includes representation expenses incurred by said officers.

Included in this account are Board meeting per diems; uniform allowances; representation expenses; and other allowances, fees and expenses.

430-932-30 Travel

This account represents expenses incurred by the utility officers and employees while on official travel.

Included in this account are meals and transportation; hotel accommodations; and other incidental expenses.

430-933-30 Training

This account represents all expenses incurred in connection with training, seminars and other continuing education programs for the officers and employees to enhance their knowledge and improve performance in the conduct of their duties and responsibilities.

Included in this account are registration/seminar fees; meals and transportation; seminar/training materials; and other related expenses.

430-934-30 Miscellaneous General Expenses

This account represents expenses incurred in connection with the general management of the utility not provided for in the accounts described elsewhere.

Included in this account are salaries and wages for miscellaneous labor; expenses incurred for: contributions for conventions and meetings, experimental and general research work, communication service not chargeable to other accounts, trustees, registrar and transfer agent fees and expenses, member or stockholders' meeting expenses, publishing and distributing annual reports to members, institutional or goodwill advertising, and public notices of financial, operating and other data required by regulatory statutes, not including however, notices required in connection with acquisitions of property.

WESM COMPLIANCE

Under the WESM Rules the following are the costs or expenses that a distribution utility has to provide for:

- Market Fees

The cost of administering and operating the WESM which shall be recovered by the Market Operator through a charge to be imposed on all WESM Members or WESM transactions, provided such charge shall be filed by the Market Operator with the ERC for approval, consistent with the R.A. No. 9136. *(Section 2.10.1 of the WESM Rules)*

The components shall include, but are not limited to:

a) Registration fees, comprising an annual fee payable by each WESM Member for the category or categories which they are registered;

b) Metering fees to recover the Market Operator's budgeted revenue requirements for the collection, storage and processing of metering data;

c) Billing and settlement fees, to recover the Market Operator's budgeted revenue requirements for providing the billing and settlements service, as described in Chapter 3 of the WESM Rules;

d) Administration fees, to recover the remainder of the Market Operator's budgeted revenue requirements not covered by (a), (b) and (c);

e) Costs reasonably incurred by the PEM Board and the committees and working groups that the Philippine Electricity Market (PEM) Board appoints under the WESM Rules, Section 2.10.4 of the WESM Rules; and

f) Market Management Software and upgrades costs recovery. *(not currently part of the WESM Rules but its inclusion is in the process of filing for approval).*

- Costs and Expenses Relative to the Provision and Maintenance of Security to the WESM

DUs are mandated to source at least 10% of their power requirements from the Spot Market. As such, DUs are also categorized as Trading Participants. Unless exempted by the Market Operator *(criteria for exemption as specified under Section 3.15.2.2 of the WESM Rules)*, DUs, as Trading Participants, are required to provide and maintain a security *(forms of which are specified under Section 3.15.3)* as mandated under Section 3.15.2.1 of the WESM Rules. Doing so will entail costs and expenses such as documentation, interest expenses if funds are borrowed to acquire such security, etc.

420-000-40 CONSUMER ACCOUNTS EXPENSES (REGULATED RETAIL SERVICES)

420-900-40 Supervision, administration & management of retail services

This account represents expenses incurred in the general direction, supervision administration and management of consumer accounting and collection activities.

Direct supervision of a specific activity shall be charged to the appropriate expense account.

Included in this account are salaries and wages of employees directly involved in the direction, supervision, administration and management of the consumer accounting activities; and other expenses related to the activities described above.

420-901-40 Planning, installation and maintenance of consumer meter installations

This account represents expenses incurred in the planning, installation and maintenance of consumer meter installations. Included in this account are salaries and wages of employees directly involved in the planning, maintenance and installation of the consumer meter installations; and other expenses related to the activities described above.

420-902-40 Meter Reading Expenses

This account represents expenses in reading consumer meters and determining consumption when performed by employees engaged in reading meters.

Included in this account are salaries and wages in: preparing forms for obtaining meter readings, inspecting time clocks, checking seals, etc., when performed by Meter Readers and the work represents a minor activity incidental to regular meter reading routine, reading meters including demand meters, and obtaining load information for billing purposes, computing consumption from Meter Reader's book or from reports done by employees engaged in reading meters, reviewing meter reading reports used for billing purposes, collecting from prepayments meters when incidental to meter reading, and computing and reviewing estimated or average consumption performed by employees engaged in reading meters; and materials and expenses incurred for: badges, lamps and uniform, demand charts, meter reading records and binders and forms for recording readings, and transportation, meals and incidental expenses.

420-903-40 Information Technology (consumer related)

Consumer related IT systems are those dedicated to providing and supporting customer services, including Distribution Connection Services.

420-904-40 Consumer Records and Collection Expenses

This account represents expenses incurred in the course of working on consumers applications, contracts, orders, credit investigations, billing and accounting, collections and complaints.

Included in this account are salaries and wages in: receiving, preparing, recording and handling routine orders for service, disconnections, transfers or meter tests initiated by the consumer, excluding the cost of carrying out such orders, which is chargeable to the account appropriate for the work called for by such orders, investigations of consumers' credit and keeping of records pertaining thereto, including records of uncollectible accounts written off, receiving, refunding or applying consumer deposits, and maintaining consumer deposit, line extension and other miscellaneous records, checking consumption shown in Meter Readers' reports where incidental to preparation of billing data, preparing address plates and addressing bills and delinquent notices, preparing billing data, operating billing and bookkeeping machines, verifying billing records with contracts or rate schedules, preparing delivery and delivering bills, collecting payments from consumers including collection from prepayment meters unless incidental to meter reading operations, balancing collections, preparing collections for deposit and cash reports, preparing mailing or delivering delinquent notices and preparing reports of delinquent accounts, posting collections and other credits or charges to consumer accounts, balancing consumer accounts and controls, final meter reading of delinquent accounts when done by Collectors incidental to regular activities, disconnecting and reconnecting service due to non-payment of bills, receiving, recording and handling of inquiries, complaints and request for investigations from consumers, including preparation of necessary orders, but excluding the cost of carrying out such orders, which is chargeable to the account appropriate for the work called for by such orders, statistical and tabulating work on consumer accounts and revenues, but not including special analyses for sales department, rate department, or other general purposes, unless incidental to regular consumer accounting routines, preparing meter reading sheets, and determining consumption and computing estimated or average consumption when performed by employees other than those engaged in reading meters; and materials and expenses incurred for: address plates and supplies, cash overages and shortages, commissions or fees to others for collecting, payments to credit organizations for investigations and reports, postage, transportation, including transportation of consumer bills and meter books under centralized billing procedures, transportation, meals and incidental expenses, bank charges, exchange and other fees for cashing and depositing consumers' checks, forms for recording orders for services, removals, etc., and rent of mechanical equipment.

420-905-40 Uncollectible Accounts (Bad debts)

This account represents provision for losses arising from non-collection of receivables or recovery from appropriately invoiced customers, after taking all prudent steps trying to recover the outstanding amounts.

Included in this account is the amount estimated or set-up as provisions for uncollectible accounts, or such steps as notifying the customers of the outstanding amounts, and employing debt collection agencies if no reaction is forthcoming.

420-906-40 Informational and Instructional Advertising Expenses

This account represents expenses incurred in activities which primarily convey information as to what the utility urges or suggests consumers should do in utilizing electric service.

Included in this account are salaries and wages in: direct supervision of informational activities, preparing informational materials for newspapers, periodicals, etc. including those for radio and TV programs, preparing informational booklets, bulletins, etc. for direct mailing, preparing informational windows and other displays, and employing agencies, selecting media and conducting negotiations in connection with the placement of information programs; and materials and expenses for: use of newspapers, periodicals, bulletin boards, radio, etc. for informational purposes, postage or direct mailing to customers, exclusive of posters related to billings, printing of informational booklets, dodgers, bulletins, etc., supplies and expenses in preparing informational materials by utility, and office supplies.

420-907-40 Miscellaneous Consumer Services Expenses

This account represents the expenses incurred in connection with consumer service and informational activities which are not included in other consumer information expense accounts described herein.

Included in this account are salaries and wages in: general clerical and stenographic work not assigned to specific customer service and information programs, and miscellaneous labor; and materials and expenses for: communication service, and printing, postage and office supplies.

420-908-40 Energy trading expenses

This account represents the expenses incurred in connection with energy trading for energy consumed as part of regulated retail services.

The cost of purchased energy, or other generation charges, is not part of this account.

DISTRIBUTION CONNECTION SERVICES

The activities related to Distribution Connection Services are similar to those listed for the operation and maintenance of a Distribution System, as listed above, but only in so far as they apply to Distribution Connection Assets and Services.

The activities are primarily concerned with the cost of labor, materials used and expenses incurred in work on or maintenance of consumer installations in inspecting premises and in rendering services to customers of the nature of those indicated by the list of items hereunder.

Included in this account are salaries and wages in: supervising consumer installation work, inspecting premises including check of wiring for code compliance, investigating, locating and clearing grounds on consumer’s wiring, investigating service complaints, including load tests of motors and lighting and power circuits on consumers’ premises, field investigations of complaints on bills or of voltage, installing, removing, renewing and changing lamps and fuses, radio, television and similar interference work including erection of new serials on consumers’ premises and patrolling of lines, testing of lighting arresters, inspection of pole hardware, etc., and examination on or off premises of consumers’ appliances, wiring or equipment to locate cause of interference, installing, connecting, reinstalling or removing leased property on consumers’ premises, cost of changing consumers’ equipment due to changes in service characteristics, and investigation of current diversion including setting and removal of check meters and securing special readings thereon, special calls by employees in connection with discovery and settlement of current diversion, changes in consumer wiring and any other labor cost identifiable as caused by current diversion; materials and expenses for: lamps and fuse renewals, materials used in servicing consumers’ fixtures, appliances and equipment, power, light, heat, telephone and other expenses of repair department, tools, transportation, including pickup and delivery charges, meals, traveling and incidental expenses, and rewards paid for discovery of current diversion; and amounts billed consumers for any work.

Also included in this account are all costs associated with the maintenance of Distribution Connection Assets.

APPENDIX C: DEFINITION OF INDICES USED FOR THE PERFORMANCE INCENTIVE SCHEME

In this appendix, the various indices that will be used for the performance incentive scheme are defined and the method for their calculation is explained.

C1. Definitions of terms for performance indices

The definitions given below are for the purposes of the measurement indices only and not intended to be general definitions for the RDWR or the Position Paper.[80]

End-user. Any person or entity requiring the supply and delivery of electricity for its own use.

Excluded Event. An event for which any resulting Interruption should be excluded from the performance data on which the calculation of the performance index is based. These Excluded Events are as described in Section 10.3.7 above.

Interruption. The loss of service to one or more End-users.

Long-duration Voltage. The average root-mean-square (RMS) value of a voltage reading taken at a Measurement Point, where the reading is taken for a one (1) minute duration.[81]

Measurement area. The Distribution System for which a performance index is calculated.

Measurement period. The period over which a performance index is calculated.

Measurement point. A random point, anywhere on a Distribution System, at which a measurement is taken in order to test compliance with a prescribed service level.

Momentary Interruption. A single operation of an interrupting device that results in a voltage zero, causing a momentary loss of service (for less than five minutes) to one or more End-users.

Notification date. The date on which a notice is served to an applicant for a Regulated Distribution Service (including, for the purpose of this definition, applications for Distribution Connection Services). Such notice is deemed to be delivered on the day that notification is faxed or submitted by electronic mail, or three working days after such notice was posted using normal mail services.

Outage. The state of a component (or group of components) when it is not available to perform its intended function due to some event directly associated with that

[80] These definitions correspond as closely as practicable with those in the Philippines Distribution Code and the IEEE Standard 1366-2003 (IEEE Guide for Electric Power Distribution Reliability Indices)

[81] This assumes that a voltage recording device will be available that can provide an average voltage reading over a period. Where such a device is not present, the Long-duration Voltage can be approximated by taking five (5) instantaneous readings of the (true) RMS voltage value at a Measurement point at consecutive 15 second intervals and averaging these readings.

component (or group of components). An Outage may, or may not give rise to an Interruption.

Planned Interruption. An Interruption which results when a component or components of the Distribution System are deliberately taken out of service at a selected time and of which advance notice of at least three (3) working days is given to End-users, detailing the time the Interruption will occur and the anticipated duration of the Interruption.

Primary side of Distribution System. The portion of the Distribution System excluding the Secondary Side of the Distribution System. It includes subtransmission networks.

Response date. Date on which a response is received from an applicant for a Regulated Distribution Service (including, for the purpose of this definition, applications for Distribution Connection Services). Such notice is deemed to be received on the day that notification is faxed or submitted by electronic mail, or three working days after such notice was posted using normal mail services.

Secondary side of Distribution System. Distribution transformers and the low voltage network on the secondary side of distribution transformers, including Distribution Connection Assets.

Sustained Interruption. An Interruption with a duration of five minutes or longer.

Tripping Event. An event caused by the operation of an interrupting device on an electrical distribution circuit, where such operation is caused by an external event, not the deliberate operation of the device by an operator, and where the event gives rise to a sustained (five minutes or longer) Outage of the circuit.

Unplanned Interruption. Any Interruption which is not a Planned Interruption.

C2. Price-related incentive scheme

C2.1 SAIFI

Definition of index : System average interruption frequency index

Description : The average number of Sustained Interruptions experienced per End-user in the Measurement Area over the Measurement Period.

Calculation : The SAIFI is calculated using the following formula:

$$SAIFI = \frac{\sum N_i}{N_T}$$

where,

N_i = Number of End-users experiencing Sustained Interruptions caused as a result of a single event *i*.

$\sum N_i$ = Total number of Sustained Interruptions experienced by End-users within the Measurement Period.

N_T = Total number of End-users served in the Measurement Area (average over the Measurement Period).

Comments : i. The SAIFI calculation includes planned and unplanned interruptions.

ii. Only Sustained Interruptions are considered.

- SAIFI is to be calculated across the full End-user base, for the whole Regulated Distribution System regardless of the voltage level at which the End-user is served or the capacity of a connection.
- Interruptions arising from Excluded Events are not to be taken into account in calculating the SAIFI.

C2.2 CAIDI

Definition of index : Customer average interruption duration index

Description : The average time required per Sustained Interruption to restore service to the an End-user (measured in minutes).

Calculation : The CAIDI is calculated using the following formula:

$$CAIDI = \frac{\sum (r_i N_i)}{\sum N_i}$$

where,

N_i = Number of End-users experiencing Sustained Interruptions caused as a result of a single event *i.*

$\sum N_i$ = Total number of Sustained Interruptions experienced by End-users within the Measurement Period.

r_i = Duration of a Sustained Interruption (in minutes) caused as a result of an event *i*.

$\sum (r_i N_i)$ = Total customer-minutes of Sustained Interruptions experienced over the Measurement Period.

Comments : i. The CAIDI calculation includes Planned and Unplanned Interruptions.

ii. Only Sustained Interruptions are considered.

iii. CAIDI is to be calculated across the full End-user base affected by interruptions, for the whole Regulated Distribution System, regardless of the voltage level at which the End-user is served or the capacity of the connection.

iv. Interruptions arising from Excluded Events are not to be taken into account in calculating the CAIDI.

C2.3 Planned SAIDI

Definition of index : System average interruption duration index (for Planned Interruptions)

Description : The average duration of Sustained Interruptions per End-user over the Measurement Period, for Planned Interruptions (measured in minutes).

Calculation : The SAIDI is calculated using the following formula:

$$SAIDI = \frac{\sum (r_i N_i)}{N_T}$$

where,

N_i = Number of End-users experiencing Sustained Interruptions caused as a result of a single planned event *i*.

r_i = Duration of a Sustained Interruption (in minutes) caused as a result of a planned event *i*.

$\sum (r_i N_i)$ = Total customer-minutes of Sustained Interruptions experienced over the Measurement Period, arising from Planned Interruptions.

N_T = Total number of End-users served in the Measurement Area (average over the Measurement Period).

Comments :

i. The planned SAIDI is to be calculated for Planned Interruptions only.

ii. Only Sustained Interruptions are considered.

iii. Planned SAIDI is to be calculated across the full End-user base, for the whole Regulated Distribution System, regardless of the voltage level at which the End-user is served or the capacity of the connection.

iv. Interruptions arising from Excluded Events are not to be taken into account in calculating the planned SAIDI.

C2.4 Voltage violations

Description : The probability that the Long-duration Voltage at any Measurement point on the Distribution System falls between 90% and 110% of the nominal voltage level at that point, based on representative sample measurements taken over the Measurement Period.

Calculation : A voltage violation exists where the measured Long-duration Voltage (V_m) falls outside the following limits:

$$V_m \geq 1.1V_n$$

or

$$V_m \leq 0.9V_n$$

where,

V_m = The Long-duration Voltage measured at a Measurement Point

V_n = The nominal (RMS) voltage level at the Measurement Point

The probability of a voltage violation occurring on the Distribution System is calculated as follows :

$$pV_v = \frac{Number\ of\ voltage\ violations\ encountered}{Number\ of\ long\ duration\ voltage\ readings\ taken}$$

where,

pV_v = Probability of a voltage violation occurring over the Measurement Period

Comments :

i. The Long-duration Voltage measurements must be taken in sufficient quantity, at representative Measurement Points across the full Distribution System and at various times of the load cycle to provide a true representation of voltage violations on the Distribution System.

ii. Details of the Long-duration Voltage measurement program must be presented for the approval to the ERC prior to implementation of the performance incentive scheme.

C2.5 System losses

Description : Technical and non-technical losses occurring on a Distribution System during the conveyance of electricity to End-users.

Calculation : The losses are calculated as follows :

$$SL = \frac{(UI_t - UD_t) \times 100}{UI_t} - 1\%$$

where, [82]

SL = Total technical and non-technical system losses (measured in %) over the Measurement Period

[82] The 1% allowance is for administrative losses, covering energy required for the proper operation of the Distribution System (which includes consumption by essential loads at distribution substations, offices of the distribution utilities, warehouses and workshops of the distribution utilities and other essential loads of the utilities). This is in accordance with the maximum figure allowed under Rule IX of the Rules and Regulations Implementing Republic Act No. 7832.

UI_t = The total MWh[83] energy delivered to a Distribution System over the Measurement Period, measured as the sum of all the energy delivered to the Distribution System over that Measurement Period, at each Grid Connection Point and connection point to an embedded generator

UD_t = The total invoiced energy delivered (in MWh) to End Users connected to a Distribution System over the Measurement Period.[84]

Comments :

i. All generation connection points where energy is delivered into the Distribution System should be taken into account.

ii. These generation connection points are to be described to the ERC and the ERC has to be notified of any changes in or additions to connection points.

C2.6 Time to process applications for Regulated Distribution Services

Description : The average time between receiving an application for a Regulated Distribution Service (including, for the purpose of this measure, applications for Distribution Connection Services), processing and approving the application.

Calculation : The average time to process applications will be calculated as follows:

$$TA = \frac{\sum (DatN_i - DL_i - DatA_i)}{AplCom}$$

where:

TA = The average time to process an application (in days). This is calculated for applications for which the processing was completed during the Measurement Period.

$DatA_i$ = Date when an application *i* for a Regulated Distribution Service is received, converted to a numerical index that allows the calculation of calendar days elapsed between this date and another.

$DatN_i$ = Date when the customer is notified that the Regulated Distribution Service *i* has been approved (or finally disapproved), converted to a numerical index that allows the calculation of calendar days elapsed between this date and another.

DL_i = Time lost in processing application *i* due to factors outside the control of the Regulated Entity (measured in days). Any

[83] Where more appropriate GWh can be used as the measurement unit for this index

[84] Note that this figure includes those units delivered to end users that are not paid for, resulting in bad debts.

such event lasting less than 12 hours shall be counted as one half-day (0.5 days).

AplCom = Number of approved applications for which processing was completed over the measurement period.

Comments :

i. Calendar days are considered for the calculations.

ii. Completed processing means the point at which an applicant is notified that its application for a Regulated Distribution System has been approved and the terms for this approval are notified.

iii. Time lost due to factors outside the control of Regulated Entities will be limited to the following :

- time to obtain licenses, permissions or approvals from parties external to Regulated Entities, from the date that such applications are lodged or when the required response is obtained;[85] and
- time awaiting further information from an applicant, without which such applications cannot proceed, from the Notification Date for a request for information until the Response Date, when an answer or commitment is received that allows processing of the application to proceed.

C2.7 Time to connect premises to the Regulated Distribution System

Description : The average time for providing a connection to a Regulated Distribution Service after all government (local and national) approvals have been obtained and the Regulated Entity requirements have been met by the applicant for the service.

Calculation : The average time to provide applications will be calculated as follows :

$$TC = \frac{\sum (DatC_i - DL_i - DatR_i)}{ConCom}$$

where:

TC = The average time to complete a connection to the Regulated Distribution System (in calendar days). This is calculated for connections completed during the Measurement Period.

$DatC_i$ = Date when a connection *i* was completed, converted to a numerical index that allows the calculation of calendar days elapsed between this date and another.

$DatR_i$ = Date when the connection *i* was ready to commence after receiving all necessary approvals and the applicant has met all requirements for the connection to proceed, converted to a

[85] Which could include the final rejection of the application, resulting in the inability of the Regulated Entity to provide the required service.

numerical index that allows the calculation of calendar days elapsed between this date and another.

DL_i = Time lost in providing connection *i* due to factors outside the control of the Regulated Entity (measured in days). Any such event lasting less than 12 hours shall be counted as one half-day (0.5 days).

ConCom = Number of connections completed over the measurement period.

Comments :

i. Calendar days are considered.

ii. Completed connection mean the date at which the applicant is notified that it can start consuming electricity through the connection point, after all testing and commissioning work and the necessary certification have been completed.

iii. Time lost due to factors outside the control of Regulated Entities will be limited to the following:

- time that access to the connection site is not possible due to actions or non-actions by the connection applicant or where severe weather conditions, natural or man made disasters prevent access to the site; and
- time awaiting further information from an applicant after it has been notified of a problem that hinders construction of the connection point, from the Notification Date until the Response Date when an answer or commitment is received that allows the installation of the connection to proceed.

C2.8 Performance of call-centre – percentage of calls answered within required time

Description : The average time (in seconds) for answering a call placed to a Regulated Entity's call-center (or equivalent service provider, if a formal call-center does not exist).

Calculation : The average time to answer calls, from the time a call is logged, until such time that a substantive response is provided.

Comments :

i. Only substantive responses are considered to be an answer to a call. In particular, placing calls on hold, or providing an automated response that does not directly result in the query being addressed, are not classed as substantive responses.

ii. If a call-center is not operating for any period of time, this implies that all calls made to the center during this time exceeded the penalty threshold. For such periods, Regulated Entities must provide an estimate of the number of calls that would have been missed, based on historical calling trends. Details of such events, and the supporting evidence for the Regulated Entity's forecast, must be submitted to the ERC with the quarterly performance submission.

C3. Guaranteed Service Level incentive scheme

C3.1 GSL1 : Duration of sustained interruptions above annual threshold level

Description : The total duration of the Sustained Interruptions experienced by an End-user over the Measurement Period.

Calculation : The sum of the duration of all the Sustained Interruptions experienced by an End-user at a single Connection Point over the Measurement Period.

Comments :

i. Planned and Unplanned Interruptions are to be included.

ii. The calculation only applies to a single End-user – if the End-user should terminate its connection during the course of a Measurement Period, a new cumulative total will be started for the next End-user at the same connection point. The original End-user will also not be allowed to continue with its earlier cumulative total at its next Connection Point.

iii. Regulated Entities are obliged to maintain the cumulative total and advise an End-user if the threshold has been exceeded and it is entitled to a penalty payment.

C3.2 GSL2 : Number of Sustained Interruptions above annual threshold level

Description : The total number of Sustained Interruptions experienced by an End-user over the Measurement Period.

Calculation : The number of Sustained Interruptions experienced by an End-user at a single Connection Point over the Measurement Period.

Comments :

i. Interruptions include planned and unplanned outages.

ii. The calculation only applies to a single End-user – if the End-user should terminate its connection during the course of a Measurement Period, a new cumulative total will be started for the next End-user at the same connection point. The original End-user will also not be allowed to continue with its earlier cumulative total at its next Connection Point.

iii. Regulated Entities are obliged to maintain the cumulative total and advise an End-user if the threshold has been exceeded and it is entitled to a penalty payment.

C3.3 GSL3 : Restoration of supply after fault on Secondary Side of Distribution System

Description : The duration of an Interruption to an End-user resulting from a fault on the Secondary Side of the Regulated Distribution System, including on the Distribution Connection Assets.

Calculation : The period between the occurrence of a fault on the Secondary Side of the Distribution System, or the time at which such a fault is reported to a Regulated Entity, and the time at which the fault has been repaired and service to the affected End-user restored.

Comments : i. Planned Interruptions are not included.

ii. Where more than one End-user is affected by the same fault, and the time to restore exceeds the threshold, penalties will be payable to all End-users affected.

iii. Temporary restoration of supply, defined as restoration for less than two hours, does not constitute restoration in terms of this index and the calculation period will extend from the original occurrence of the fault (or the time it was reported), until such time that the supply is fully restored (with fully restored defined as available at normal supply capacity for an uninterrupted period longer than two hours).

C3.4 GSL4 : Failure to provide a connection on time

Description : A Regulated Entity fails to provide a connection to the Regulated Distribution System on the day previously agreed with a customer. This agreement can be specific to a customer, or could be the general connection period to which a Regulated Entity has committed itself and which has been generally communicated to its consumers.

Calculation : The number of days (or parts of days) between the date at which a connection to the Regulated Distribution System is provided and the day agreed with a customer for the connection, if the date agreed is earlier than the date on which the connection is provided. The penalty will increase with the penalty amount for each day that the connection is late, up to a maximum of five days.

Comments : i. The agreed connection day should be put in writing, or in verifiable electronic form.

ii. Changes to the originally agreed connection day made with the mutual, prior approval of the Customer and the Regulated Entity will result in a new connection date. In this case, penalties will only be calculated from the new connection date forward.

Note that in certain circumstances, an alternative definition is applied by Regulated Entities for GSL4:

Alternative definition for GSL4:

Description : A Regulated Entity fails to provide a connection to the Regulated Distribution System within the period previously agreed with a customer. This agreement can be specific to a customer, or could be the general connection period to which a Regulated Entity has committed itself and which has been generally communicated to its consumers.

Calculation : The number of days (or parts of days) that a connection to the Regulated Distribution System is provided after the period guaranteed or agreed for such a connection to be provided. The penalty will increase with the penalty amount for each day that the connection is late, up to a maximum of five days.

Comments : i. The agreed connection period should be put in writing, or in verifiable electronic form.

ii. Changes to the originally agreed connection period made with the mutual, prior approval of the Customer and the Regulated Entity will result in a new connection period. In this case, penalties will only be calculated for connections provided after the new agreed connection period.

C4. Information disclosure

<u>Network performance indices</u>

C4.1 MAIFI

Definition of index : Momentary average interruption frequency index

Description : The average frequency of momentary interruptions over the Measurement Period.

Calculation : The MAIFI is calculated with the following formula :

$$MAIFI = \frac{\sum N_{mi}}{N_T}$$

where:

N_{mi} = Number of End-users experiencing Momentary Interruptions as a result of Momentary Interruption event *i*.

N_T = Total number of End-users served in the Measurement Area (average over the Measurement Period).

Comments : i. The MAIFI is to be calculated across the full End-user base, for the whole Regulated Distribution System, regardless of the voltage level at which the End-user is served or the capacity of the connection.

ii. Interruptions arising from Excluded Events are not to be taken into account in calculating the planned SAIDI.

C4.2 Frequency of Tripping Events per 100 circuit-km

Description : The frequency of Tripping Events experienced on subtransmission and distribution circuits forming part of the Primary Side of the Distribution Network per 100 km of circuit length making up the circuits forming part of the Primary Side of the Distribution Network.

Calculation : Frequency of tripping events per 100 circuit-km:

$$FTI = \frac{Number\ of\ tripping\ events\ over\ Measurement\ Period}{(\frac{CK}{100})}$$

where:

FTI	=	Frequency of tripping events per 100 circuit-km
CK	=	Length of circuits in the Primary Side of the Distribution Network (distribution and subtransmission circuits) measured in kilometer

Comments : i. The index is to be calculated for the whole Regulated Distribution System.

ii. Only Tripping Events associated with components of the Regulated Distribution System are to be considered.

C4.3 Average time to respond to queries and complaints

Description : The average time between receiving a substantive query or complaint and responding to it in a substantive manner.

Calculation : The average time will be calculated as follows :

$$AQT = \frac{\sum (DatR_i - DL_i - DatQ_i)}{QueNum}$$

where:

AQT	=	The average time to respond to queries and complaints
$DatR_i$	=	Date when a substantive response is provided to a query or complaint (*i*), converted to a numerical index that allows the calculation of calendar days elapsed between this date and another. Should a query or complaint not be resolved or substantially responded to during a Measurement Period, $DatR_i$ will be the last day of that period.
$DatQ_i$	=	Date when a substantive query or complaint (*i*) is received by a Regulated Entity, converted to a numerical index that allows the calculation of calendar days elapsed between this date and another.
DL_i	=	Time lost in processing query or complaint (*i*) due to factors outside the control of the Regulated Entity measured in days. Any such event lasting less than 12 hours shall be counted as one half-day (0.5 days).
QueNum	=	Number of queries or complaints received over the Measurement Period.

Comments : i. Calendar days are considered for the calculations.

ii. Substantive reaction is considered to be a reaction that either fully addresses a query or complaint, or sets in motion a chain of actions that will address the issue on which a complaint was laid. Merely acknowledging receipt of a query or complaint is not considered substantive reaction.

iii. Casual or facetious queries or complaints are not considered substantive and should be excluded from this measure. Queries or complaints made purely for vindictive or unwarranted reasons are likewise to be excluded.

iv. Time lost due to factors outside the control of Regulated Entities will be limited to the following :

- time to obtain information from third parties, not being employees or contractors of the Regulated Entity after requests for such information has been passed on; and
- time awaiting further information from an applicant, without which further processing of the query or complaint cannot proceed, from the Notification Date for a request for further information until the Response Date, when the information is received that allows the query or complaint to be addressed.

C4.4 Average time to reconnect a service after payment of all dues

Description : The average time to reconnect a service that had been disconnected before due to non-payment of dues, after all such dues have been fully settled.

Calculation : The average time will be calculated as follows:

$$ARS = \frac{\sum (DatS_i - DL_i - DatD_i)}{SerRc}$$

where:

ARS = The average time to reconnect a service after all dues have been settled and upon full compliance to LGU and DU requirements (where needed)

$DatS_i$ = Date when a service i is fully restored after all dues have been settled and upon full compliance to LGU and DU requirements (where needed), converted to a numerical index that allows the calculation of calendar days elapsed between this date and another.

$DatD_i$ = Date when full settlement of all outstanding dues in relation to service i is made and upon full compliance to LGU and DU requirements (where needed), converted to a numerical index that allows the calculation of calendar days elapsed between this date and another.

DL_i = Time lost in restoring service i due to factors outside the control of the Regulated Entity (measured in days). Any such event lasting less than 12 hours shall be counted as one half-day (0.5 days).

SerRc = Number of services reconnected over the Measurement Period, after settlement of dues for these services.

Comments :

i. Calendar days are considered for the calculations.

ii. Time lost due to factors outside the control of Regulated Entities will be limited to the following:

- time that access to the connection site is not possible due to actions or non-actions by the connection applicant or where severe weather conditions, natural or man made disasters prevent access to the site; and
- time awaiting further information from an applicant after it has been notified of a problem that hinders reconnection of the service, from the Notification Date until the Response Date when an answer or commitment is received that allows the installation of the connection to proceed.

C5. Templates for Service Performance Measurement

For the purposes of the performance incentive scheme required in terms of Clause 4.18.1 of the RDWR and as expanded above, service performance templates will be provided by the ERC at the Pre-filing conference for the Revenue Applications.

APPENDIX D: ENTRY POINTS INTO PBR

Following ERC Resolution No. 12-02 Series of 2004, the privately owned Distribution Utilities in the Philippines will enter Performance Based Regulation according to the schedule in Table L1 below. The dates for the reset process, as well as the Regulatory Periods associated with each entry group are also indicated.[86]

Table D1: Further Entry Groups for Performance Based Regulation

First entry group Cagayan Electric Light & Power Company Dagupan Electric Corporation Manila Electric Company	Reset period Jan 1, 2010 to Jun 30, 2011 Second Regulatory Period Jul 1, 2007 to Jun 30, 2011 Third Regulatory Period Jul 1, 2011 to June 30, 2015
Second Entry Group Cotabato Light & Power Company, Inc. Iligan Light & Power Company, Inc. Mactan Electric Company	Reset period Apr 1, 2011 to Mar 31, 2013 Second Regulatory Period Apr 1, 2009 to Mar 31, 2013 Third Regulatory Period Apr 1, 2013 to Mar 31, 2017
Third entry group Cabanatuan Electric Corporation Davao Light & Power Company, Inc. Ibaan Electric and Engineering Corp. La Union Electric Company, Inc. Tarlac Electric Inc. Visayan Electric Company	Reset period Jan 1, 2009 to Jun 30, 2010* Second Regulatory Period Jul 1, 2010 to Jun 30, 2014 Third Regulatory Period Jul 1, 2014 to Jun 30, 2018
Fourth entry group Angeles Electric Corporation Bohol Light Company, Inc. Clark Electric Distribution Company Panay Electric Company Subic Enerzone Corporation San Fernando Electric Light & Power Company	Reset period Sep 1, 2009 to Mar 31, 2011* Second Regulatory Period Apr 1, 2011 to Mar 31, 2015 Third Regulatory Period Apr 1, 2015 to Mar 31, 2019

[86] None of the later entrant groups were subject to a First Regulatory Period as described in the original Distribution Wheeling Rate Guidelines for the first entrant group. All later entrant groups therefore commence Performance Based Regulation in the Second Regulatory Period.