

If, after considering the opinion of the Regulatory Reset Expert(s), in the opinion of the ERC the consumption or demand forecasting for any Regulated Entity is not reasonable, he ERC will determine the forecasts for that Regulatory 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.

As part of their forecasts, Regulated Utilities are required to submit historical consumption and demand figures for the last five calendar years before the start of the Second Regulatory Period (making such forecasts as required for the remaining months of the last year), broken down as far as possible into the divisions discussed in section 5.1 above. Forecasts for the 2008 regulatory year should also be provided (that is the period October 1 2007 to September 30, 2008).

5.3 Data requirements

Appendix I provides the templates for the consumption and demand figures to be provided to the ERC.

6. CORPORATE INCOME TAX

6.1 Income tax forecasts

The calculation of the estimated income tax is described in clause 4.14 of the RDWR. For each Regulatory Year, it is based on applying the corporate tax rate of the Regulated Entity to the forecast net taxable income of the Regulated Entity for the previous Regulatory Year, including the case where the previous year was the last year before the start of the Second Regulatory Period.

Tax losses will be recoverable as indicated, and will form part of the net taxable income.

Taxable income is estimated based on the maximum annual capped price and the estimated energy consumption for each Regulatory Year, from which will be deducted the estimated operating and maintenance expenditure, interest payments on outstanding debt and depreciation of the historical asset base for that Regulatory Year. The following should be noted :

- Depreciation of the opening asset base will be in real terms and will be based on the historical asset base, not the ODRC of the Regulatory Asset Base.³⁷
- Depreciation of the asset base acquired after the start of the Second Regulatory Period will be similar to that forming part of the Rolled Forward Depreciated Regulatory Asset Base.
- Interest payments will be based on the value of the Regulatory Asset Base, and the debt ratio and cost of debt used for the calculation of the WACC.

The regulatory tax losses relate only to those losses arising from the operation of the Regulated Distribution System. As such, it would only arise if the taxable income of a Regulated Entity, as defined in clause 4.14.3 of the RDWR is a negative amount for any Regulatory Year, or for the last year of the First Regulatory Period.

³⁷ As noted in section 4.1.15, records have to be maintained for both the optimized depreciated replacement cost and historical cost values of the Regulated Distribution System asset base.

7. PRICE CONTROL

7.1 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 allowed annual revenue for each year of the Second Regulatory Period
- Convert this allowed revenue to the present value at the start of the Second Regulatory Period
- Determine the opening price for the Second Regulatory Period
- Based on the forecast energy consumption and inflation rates, and the P_0 factor, determine the smoothing factor (X-factor)
- Determine the Smoothed Maximum Average Price caps for the Second Regulatory Period based on the opening price, the forecast inflation and the X-factor.

7.1.1 *Average price for distribution before the Second Regulatory Period*

The calculation of the price path for the Second Regulatory Period relies partly on the average price for electricity distribution that a Regulated Entity received before the start of the Second Regulatory Period. This average price is calculated in terms of clause 4.5 of the RDWR, and is based on the revenue billed for Regulated Distribution Services provided through the relevant Regulated Distribution System and the amount of energy delivered through the Regulated Distribution System during the 12 months ending on March 31, 2008.

7.1.2 *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 Second Regulatory Period, which is based on the annual revenue requirements for a Regulated Entity as established through the use of the building block methodology, converted to present values by using the Regulatory WACC;
- the anticipated inflation rate for each year of the Second Regulatory Period;
- the forecast energy consumption for each Regulatory Year of the Second Regulatory Period;
- the opening maximum average price cap at the start of the Second 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.

7.1.3 Forecast inflation rates

As described in section 3.1.4, Regulated Entities have to submit CPI forecasts for the Philippines and the USA as part of their expenditure forecasts which will be verified by the ERC. The CPI figures as approved by the ERC will form the basis of the inflation forecasts required to calculate the X-factor.

7.1.4 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 5 above.

7.1.5 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 transition to PBR.

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 Second 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.³⁸

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

7.1.6 Opening price for the Second Regulatory Period

The opening maximum average price cap at the start of the Second Regulatory Period is calculated from the average price charged for electricity distribution as noted in section 7.1.1, adapted for inflation, the P_0 factor and the X-factor. This calculation is given in clause 4.15.4(a) of the RDWR.

7.1.7 Smoothed price path for the Second Regulatory Period

The smoothed annual average price caps for the Second 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.

7.2 Price adjustments during the Second 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 7.1.

³⁸ Since the actual inflation rate is likely to vary from the estimate at the start of the Second 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.

At the start of the Second Regulatory Period, the opening maximum average price cap will be the smoothed price cap as calculated in section 7.1.6. Thereafter the price cap will be based on the actual weighted index, a performance incentive factor and correction factors, as described below.

7.2.1 *Weighted Index for inflation and exchange rate changes*

Calculation of the 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 0.6 will apply to the Philippine CPI changes and a weighting of 0.4 to the combined exchange rate and USA CPI changes.

7.2.2 *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 June quarter three months before the start of the Regulatory Year, and the same quarterly figures for the year ending on 30 June one year earlier. This process is described in clause 4.5.2 of the RDWR.

To avoid confusion, it should be noted that the years referred to in this clause are Regulatory Years, not calendar years. For example, if the Regulatory Year considered is 2010 (i.e. that ending in September 2010), the term $CPI_{(QD, t-1)}$ refers to the December of Regulatory Year 2009. This is in fact the quarter ending on 31 December 2008.³⁹

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”.⁴⁰

7.2.3 *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 June quarter three months before the start of the Regulatory Year, against the same quarterly figures for the year ending on 30 June 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.

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.

³⁹ The quarter ending on 31 December 2009 would be the December quarter of Regulatory Year 2010.

⁴⁰ 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.

7.2.4 *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. Regulated Entities will be informed by September 17, 2007 if there are to be any changes to the weightings, with the reasons for any such changes.

7.2.5 *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 4.4.4).

7.2.6 *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 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.

7.2.7 *Performance incentive factor*

The performance incentive factor is described in detail in section 9. The S_t term introduces a bonus or penalty factor in the maximum annual price cap, based on the service performance of a Regulated Distribution System during the previous year.

7.3 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 Subsequent 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 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
- Bad debts recovery

For the Second Regulatory Period, the RBR_t (clause 4.3.1) and RBR_{bs} (clause 4.5) values will be set at 50% of the net income derived from related business activities. It is noted that in order to adhere to 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.

7.4 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 period for the First Entry Point and will be adapted and made available to the Regulated Entities making up the Second Entry Group.

It is intended to make the model available to Regulated Entities and other interested parties by April 30, 2007.⁴¹

⁴¹ Note that the determination of the parameters which will feed into this model will not have been completed by that stage.

8. 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 flipside, expenditure above the approved forecast levels will be to the account of a Regulated Entity.

8.1 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).

8.2 Adjustment of expenditure forecasts

In clause 9.2.4 of the RDWR provision is made for the possible adjustment by the ERC of the earlier approved 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 impact on the calculation of the allowed annual revenue during the Second Regulatory Period, or the X-factor and the maximum average price-caps.

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

- 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 forecast⁴², as measured by the coincident maximum demand;⁴³
- material differences between the actual Philippines CPI as compared with those forecast⁴⁴; and
- material differences between the actual PhP/US\$ exchange rates as compared with those forecast⁴⁵.

⁴² Material differences are defined as those cases where the actual demand is greater than 103% or less than 97% of the forecast demand.

⁴³ See section 5.1.1 for a discussion on the measurement of maximum demand.

⁴⁴ 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.

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.

8.3 Maintaining service delivery levels

Expenditure efficiencies may not 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 2004 service delivery levels have not been maintained for any Regulatory Year during the Second Regulatory Period.

The service measures that will be monitored are those discussed in section 9.3 and the historical and actual performance information submitted by Regulated Entities under the performance incentive scheme will be used to assess performance against 2007 levels. For determining whether performance levels have slipped below 2007 levels, the ERC will calculate the S-factor described in section 9.3.3 to 9.3.5 for each Regulatory Year, but will use the 2007 performance in the relevant indices as base value when assessing performance against target, instead of the historical averages as proposed for the performance incentive scheme. If the S-factor thus calculated for any Regulatory Year is less than zero, it would constitute slippage against 2007 service levels.⁴⁶

The ERC will 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.⁴⁷

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. Provision is also made for recovery of any return that a Regulated Entity may have made on approved capital expenditure on projects that were subsequently cancelled or substantially deferred.

⁴⁵ 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.

⁴⁶ If information for 2007 performance against the incentive measures is not available, only those indices for which information exist will be used.

⁴⁷ 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.

9. 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.

9.1 Interim performance incentive schemes

During consultations, it became clear that serious shortcomings exist with regard to the performance measurement information and capabilities of Regulated Entities. It is therefore necessary to make some simplifying assumptions for the performance incentive scheme used at this regulatory reset. The ERC's will require each Regulated Entity to establish a simplified, interim scheme based largely on the available historical performance data, and the performance factors that can be accurately measured by the Regulated Entity.

To refine future performance incentive schemes, the ERC will collect further performance data during the Second Regulatory Period, as well as conduct studies to ascertain customer preferences with regard to various service levels, willingness to pay for improved service, and the cost to improve service levels. The information will be used at the reset for the Third Regulatory Period to redesign the current proposed performance incentive scheme.

The following approach with regard to the interim performance incentive scheme will be adopted:

- a) The performance incentive scheme described in section 9.2 below will only be implemented from the start of the third regulatory period.
- b) Drawing from this framework, each Regulated Entity will be required to design its own simplified performance incentive scheme for the Second Regulatory Period. This would take into account those indices in the framework that it can measure and for which it has historical data, or use indices that could, over time, be rolled into the final framework. The Regulated Entities are also to suggest, with appropriate justification, the performance bands against which actual performance should be measured for each index, and the relative weighting that should apply to each index.
- c) The interim performance incentive schemes will be submitted with the Regulated Entities' filing of their revenue requirements for the Second Regulatory Period, scheduled for October 15, 2007.
- d) To support the effective implementation of the performance incentive scheme, the ERC will request the Regulated Entities to submit draft versions of their intended performance incentive schemes for its review and comments not later than August 1, 2007. The ERC will arrange meetings to discuss these draft schemes with each Regulated Entity before August 31, 2007.
- e) The ERC will assess the incentive schemes proposed by the Regulatory Reset Experts and, if considered appropriate, will accept it for implementation during the Second Regulatory Period. If an incentive scheme is found to be inadequate, the Regulated Entity will be requested to revise or expand it. If no satisfactory resolution is achieved in a reasonable time, the ERC will design and implement such a scheme at its own discretion.

- f) Regulated Entities are required to assess the gaps between its proposed incentive scheme and that in the framework provided by the ERC. Based on this, a detailed report is to be provided to the ERC by each Regulated Entity on how it plans to address these gaps and expand its performance measurement capability over the Second Regulatory Period, to enable it to measure performance against all the indices required by the third regulatory period. The capital, operating and maintenance expenditure required for this is to be included in the forecasts for the regulatory reset, where it will be assessed by the ERC and approved if deemed efficient and appropriate. However, the ERC is aware that such expenditure may be significant and, if it is therefore found to inflate the maximum price-cap by an unacceptable degree, the ERC may decide to reduce the performance measurement requirements or extend the implementation period over two regulatory periods.

For purposes of the interim performance incentive schemes drawn up by the Regulated Entities, a price-linked incentive scheme, Guaranteed Service Levels scheme (GSL) and information disclosure scheme must be included, similar to that discussed below. The percentage of revenue involved in the incentive scheme should in general be similar to that discussed below, but may be reduced at the discretion of the ERC if it considers that the number of indices measured are too low.

To refine future performance incentive schemes, the ERC will collect further performance data during the Second Regulatory Period, as well as conduct studies to ascertain customer preferences with regard to various service levels, willingness to pay for improved service, and the cost to improve service levels.

9.2 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.⁴⁸ 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 7.2.7). 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.

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

⁴⁸ 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.

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.

9.3 Price-linked incentives

9.3.1 *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 :

$$\text{MAP}_t = [\text{MAP}_{t-1} \times \{1 + \text{CWI}_t - X\}] + S_t - K_t + \text{ITA}_t$$

where S_t is the performance incentive factor calculated as described in section 9.3.3 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.

The calculation of the performance targets will initially be largely based on historical actual performance levels by Regulated Distribution Systems. In future regulatory periods the ERC may put more weight on benchmarked performance measures, or may set stretch targets to ensure gradual performance improvement. The ERC intends to develop its information base during the Second Regulatory Period to allow it to determine realistic benchmarks or stretch targets for the Third Regulatory Period. In addition, by maintaining existing performance levels as the base performance norm, Regulated Entities will have the opportunity to set up their required performance based management support systems and implement the incentive scheme without the additional pressure of having to meet improved service levels to avoid penalties.

The S-factor will not apply for the initial Regulatory Year of the Second Regulatory Period (2009). This is to allow:

- for those indices where it is lacking, two more years of historical performance data to be collected before implementing the incentive scheme (for the 2007 and 2008 calendar years); and
- Regulated Entities the opportunity to get the required measurement and information systems in place where this is currently lacking.

9.3.2 *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 (planned SAIDI). A measure of the average duration of planned sustained service interruptions for all customers over the measurement period.⁴⁹
- 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 given in appendix D.

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). The ERC will eventually amend this to include outages on at least the larger secondary lines of a Distribution System.⁵⁰ This will not include outages to single or small groups of customers,⁵¹ but outages on major low voltage lines or distribution transformers would be included.

Regulated Entities already face a downside potential from the system loss cap that is imposed on Regulated Distribution Systems.⁵² It is therefore the intention that the system loss performance index will not have a negative measure— it will be zero or positive only.

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.

9.3.3 Calculation of the S-factor

The S-factor will be based on a weighted sum of performance components, one for each of the indices discussed in section 9.3.2. It will be calculated as follows :

⁴⁹ 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.

⁵⁰ 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.

⁵¹ Such outages are unlikely to register on the network wide SAIDI or SAIFI statistics in any case.

⁵² Distribution Utilities are only entitled to recover losses up to the capped percentage level. Any losses in excess of this are to their account.

$$S_t = \frac{[S_{SAIFI,t} + S_{CAIDI,t} + S_{SAIDI,t} + S_{VoltViol,t} + S_{Sysloss,t} + S_{Proc,t} + S_{Con,t} + S_{Call,t}] \times 0.025 ARR_t}{FQ_t}$$

where,

ARR_t = the allowed annual revenue for Regulatory Year t calculated in accordance with clause 4.7.7 of the RDWR;

FQ_t = the total amount of energy (expressed in kWh) that is forecast to be delivered to Connection Points through the relevant Regulated Distribution System during Regulatory Year t, with the forecast as approved by the ERC;

and

$$S_{SAIFI,t} = W_{SAIFI} \times Perf_{SAIFI,t-1}$$

where, $S_{SAIFI,t}$ = S-component for SAIFI for Regulatory Year t;

W_{SAIFI} = Weighting given to the SAIFI S-component; and

$Perf_{SAIFI,t-1}$ = SAIFI performance assessment for the year ending on March 31 of Regulatory Year t-1.

$$S_{CAIDI,t} = W_{CAIDI} \times Perf_{CAIDI,t-1}$$

where, $S_{CAIDI,t}$ = S-component for CAIDI for Regulatory Year t;

W_{CAIDI} = Weighting given to the CAIDI S-component; and

$Perf_{CAIDI,t-1}$ = CAIDI performance assessment for the year ending on March 31 of Regulatory Year t-1.

$$S_{SAIDI,t} = W_{SAIDI} \times Perf_{SAIDI,t-1}$$

where, $S_{SAIDI,t}$ = S-component, planned SAIDI for Regulatory Year t;

W_{SAIDI} = Weighting given to the SAIDI S-component; and

$Perf_{SAIDI,t-1}$ = Planned SAIDI performance assessment for the year ending on March 31 of Regulatory Year t-1.

$$S_{VoltViol,t} = W_{VoltViol} \times Perf_{VoltViol,t-1}$$

where, $S_{VoltViol,t}$ = S-component for voltage regulation performance for Regulatory Year t;

$W_{VoltViol}$ = Weighting given to the voltage regulation S-component; and

$Perf_{VoltViol,t-1}$ = Voltage regulation performance assessment for the year ending on March 31 of Regulatory Year t-1.

$$S_{Sysloss,t} = W_{Sysloss} \times Perf_{Sysloss,t-1}$$

where, $S_{Sysloss,t}$ = S-component for system losses performance for Regulatory Year t;

$W_{Sysloss}$ = Weighting given to the system losses S-component; and

$Perf_{Sysloss,t-1}$ = System losses performance assessment for the year ending on March 31 of Regulatory Year t-1.

$$S_{Proc,t} = W_{Proc} \times Perf_{Proc,t-1}$$

where, $S_{Proc,t}$ = S-component for time to process applications for Regulatory Distribution Services for Regulatory Year t;

W_{Proc} = Weighting given to the process time S-component; and

$Perf_{Proc,t-1}$ = Process time performance assessment for the year ending on March 31 of Regulatory Year t-1.

$$S_{Con,t} = W_{Con} \times Perf_{Con,t-1}$$

where, $S_{Con,t}$ = S-component for time to provide connection to the Regulated Distribution System for Regulatory Year t;

W_{Con} = Weighting given to the service connection time S-component; and

$Perf_{Con,t-1}$ = Connection time performance assessment for the year ending on March 31 of Regulatory Year t-1.

$$S_{Call,t} = W_{Call} \times Perf_{Call,t-1}$$

where, $S_{Call,t}$ = S-component for call-center performance for Regulatory Year t;

W_{Call} = Weighting given to the call-center performance S-component; and

$Perf_{Call,t-1}$ = Call-center performance assessment for the year ending on March 31 of Regulatory Year t-1.

9.3.4 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 put in place the following ceilings on these streams:

- a) The maximum value of the direct reward-based incentive scheme in any year will be capped at 2.5% of the allowed annual revenue.
- b) The allowance for the GSL scheme will be set at 0.5 % of the annual allowed revenue in any Regulatory Year as calculated before the GSL scheme is taken into account.

The ceiling on the direct reward-based incentive scheme is already accounted for in the formulas to calculate the S-factor, as described in section 9.3.3 above. Based on the relative importance of these indices, the extent to which they can be influenced by Regulated Entities and the ability of Regulated Entities to effectively measure them, the weightings set out in table 18 will be applied to the various performance S-components.

Table 18: 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_{Proc} | 0.10 |
| Time to connect premises | W_{Con} | 0.10 |
| Call-center performance | W_{Call} | 0.10 |

9.3.5 Determination of the performance targets for the various performance indices

The proposed methodology to determine the performance targets is discussed below. Regulated Entities are required to collect information about the performance levels of Regulated Distribution Systems against these indices over the Second Regulatory Period. This data will be used when determining the performance bands for the Third Regulatory Period.

It is the intention to set five discrete performance bands for each performance index, as illustrated in table 19 below. Performance in each of these bands would result in the allocation of a simple performance assessment value to the index being assessed. These are the “Perf”-values described in section 9.3.3.

Table 19: Proposed performance assessment bands

| Performance band | Description | Performance value |
|------------------|----------------------------------|-------------------|
| 1 | Performance greatly below target | -1.0 |
| 2 | Target not achieved | -0.5 |
| 3 | Performance as per expectation | 0 |
| 4 | Target exceeded | 0.5 |
| 5 | Target greatly exceeded | 1.0 |

The manner in which the bands will be set for each performance index is described in table 20 (a-g) below (noting that the fully-fledged version of the performance incentive scheme will only be adopted for the Third Regulatory Period).

Table 20a : Setting of performance bands for SAIFI performance

| SAIFI | |
|----------------------------------|--|
| Average SAIFI value | Average annual SAIFI for a Regulated Distribution System for the 5 years ending on Mar 31, 2012 |
| Standard deviation | Standard deviation of the annual SAIFI values for a Regulated Distribution System for the 10 calendar years ending on Mar 31, 2012 |
| Performance greatly below target | Annual SAIFI more than 2 standard deviations above the SAIFI average |
| Target not achieved | Annual SAIFI more than 1 standard deviation, but less than 2 standard deviations, above the SAIFI average |
| Performance as per expectation | Annual SAIFI between 1 standard deviation above and 1 standard deviation below the average value |
| Target exceeded | Annual SAIFI more than 1 standard deviation, but less than 2 standard deviations, below the SAIFI average |
| Target greatly exceeded | Annual SAIFI more than 2 standard deviations below the SAIFI average |

Table 20b : Setting of performance bands for CAIDI performance

| CAIDI | |
|----------------------------------|--|
| Average CAIDI value | Average annual CAIDI for a Regulated Distribution System for the 5 calendar years ending on Mar 31, 2012 |
| Standard deviation | Standard deviation of the annual CAIDI values for a Regulated Distribution System for the 10 calendar years ending on Mar 31, 2012 |
| Performance greatly below target | Annual CAIDI more than 2 standard deviations above the CAIDI average |
| Target not achieved | Annual CAIDI more than 1 standard deviation, but less than 2 standard deviations, above the CAIDI average |
| Performance as per expectation | Annual CAIDI between 1 standard deviation above and 1 standard deviation below the average value |
| Target exceeded | Annual CAIDI more than 1 standard deviation, but less than 2 standard deviations, below the CAIDI average |
| Target greatly exceeded | Annual CAIDI more than 2 standard deviations below the CAIDI average |

Table 20c : Setting of performance bands for planned SAIDI performance

| PLANNED SAIDI | |
|----------------------------------|--|
| Average planned SAIDI value | Average annual planned SAIDI for a Regulated Distribution System for the 5 calendar years ending on Mar 31, 2012 |
| Standard deviation | Standard deviation of the annual planned SAIDI values for a Regulated Distribution System for the 10 calendar years ending on Mar 31, 2012 |
| Performance greatly below target | Annual planned SAIDI more than 2 standard deviations above the planned SAIDI average |
| Target not achieved | Annual planned SAIDI more than 1 standard deviation, but less than 2 standard deviations, above the planned SAIDI average |
| Performance as per expectation | Annual planned SAIDI between 1 standard deviation above and 1 standard deviation below the average value |
| Target exceeded | Annual planned SAIDI more than 1 standard deviation, but less than 2 standard deviations, below the planned SAIDI average |
| Target greatly exceeded | Annual planned SAIDI more than 2 standard deviations below the planned SAIDI average |

Table 20d : Setting of performance bands for voltage regulation performance

| VOLTAGE REGULATION | |
|--|--|
| Target probability of voltage violation (pV _v) | 4% |
| Performance greatly below target | Probability of voltage violation greater than or equal to 6% |
| Target not achieved | Probability of voltage violation between 5% and 6% |
| Performance as per expectation | Probability of voltage violation on or between 3% and 5% |
| Target exceeded | Probability of voltage violation between 2% and 3% |
| Target greatly exceeded | Probability of voltage violation less than or equal to 2% |

Table 20e : Setting of performance bands for system losses

| SYSTEM LOSSES | |
|----------------------------------|--|
| Target for system losses | 9.5% |
| Performance greatly below target | Not applicable |
| Target not achieved | Not applicable |
| Performance as per expectation | System losses on or between 8.5% to 9.5% |
| Target exceeded | System losses between 7.0% and 8.5% |
| Target greatly exceeded | System losses less than or equal to 7.0% |

Table 20f : Setting of performance bands for time to process applications

| TIME TO PROCESS SERVICE APPLICATIONS | |
|---|---|
| Long-term average time to process a service application | Average time to process applications over the 5 calendar years ending on Mar 31, 2012 |
| Standard deviation | Standard deviation of the average time to process applications, based on actual cases for the five years ending on Mar 31, 2012 |
| Performance greatly below target | Annual average processing time more than 2 standard deviations above the long-term average value |
| Target not achieved | Annual average processing time more than 1 standard deviation, but less than 2 standard deviations, above the long-term average value |
| Performance as per expectation | Annual average processing time between 1 standard deviation above and 1 standard deviation below the long-term average value |
| Target exceeded | Annual average processing time more than 1 standard deviation, but less than 2 standard deviations, below the long-term average value |
| Target greatly exceeded | Annual average processing time more than 2 standard deviations below the long-term average value |

Table 20g : Setting of performance bands for time to provide connection

| TIME TO PROCESS SERVICE APPLICATIONS | |
|--|---|
| Long-term average time to provide a connection | Average time to provide a connection over the 5 calendar years ending on Mar 31, 2012 |
| Standard deviation | Standard deviation of the average time to provide a connection, based on actual cases for the five years ending on Mar 31, 2012 |
| Performance greatly below target | Annual average connection time more than 2 standard deviations above the long-term average value |
| Target not achieved | Annual average connection time more than 1 standard deviation, but less than 2 standard deviations, above the long-term average value |
| Performance as per expectation | Annual average connection time between 1 standard deviation above and 1 standard deviation below the long-term average value |
| Target exceeded | Annual average connection time more than 1 standard deviation, but less than 2 standard deviations, below the long-term average value |
| Target greatly exceeded | Annual average connection time more than 2 standard deviations below the long-term average value |

Table 20h : Setting of performance bands for call center performance

| TIME TO PROCESS SERVICE APPLICATIONS | |
|--|---|
| Long-term average time to provide a connection | Average percentage of calls answered after 30 seconds over the 5 calendar years ending on Mar 31, 2012 |
| Standard deviation | Standard deviation of the average percentage of calls answered after 30 sec., based on actual numbers for the five years ending on Mar 31, 2012 |
| Performance greatly below target | Annual average connection time more than 2 standard deviations above the long-term average value |
| Target not achieved | Annual average connection time more than 1 standard deviation, but less than 2 standard deviations, above the long-term average value |
| Performance as per expectation | Annual average connection time between 1 standard deviation above and 1 standard deviation below the long-term average value |
| Target exceeded | Annual average connection time more than 1 standard deviation, but less than 2 standard deviations, below the long-term average value |
| Target greatly exceeded | Annual average connection time more than 2 standard deviations below the long-term average value |

The ERC is aware that some of the data required to calculate the proposed target levels may not be available, in which case target levels may have to be set based on reduced datasets, comparisons between Regulated Distribution Systems, or with international benchmarks.

For the interim performance incentive scheme, a final decision on the performance targets will be taken based on the applications received from the Regulated Entities and after the ERC has had the chance to assess the sufficiency of the information available. The final targets for the interim scheme will only be set after further consultation with Regulated Entities and consideration of performance measurement data taken till the end of March 2008.

9.3.6 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 intends to allow these events to be excluded from the statistics used to calculate network or service performance.

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; and
- 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.

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.

The ERC will adopt the 2.5 beta method, developed by the Institute for Electrical and Electronic Engineers (IEEE)⁵³ to identify major event days.⁵⁴

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

9.3.7 *Improving service levels*

A key function of the performance incentive scheme is to encourage the improvement of network and service performance of Regulated Distribution Systems. While the scheme as proposed above will be predominantly based on targeted service levels that are derived from the historical performance of Regulated Distribution Systems, the ERC will in future regulatory periods consider adopting stretch targets

For the third regulatory period, the ERC will assess the historical performance data received for each Regulated Distribution System and, after taking into account the advice of the Regulatory Reset Expert(s), may decide that the actual historical performance of a Regulated Distribution System against one or more of the performance indices may be inappropriately high or low. If such performance levels differ substantially from the accepted norm, the ERC may then adapt the associated performance target(s) to more realistic benchmark levels.

Where it is found that a Regulated Distribution System’s historical performance against a particular performance index is substantially better than the norm, the ERC may decide to set the performance targets for the index in question somewhat below the actual historical performance. This will accord some benefits to the Regulated Entity from its historical good performance without leading to unacceptable lowering of performance levels. Such cases are expected to be unusual.

⁵³ 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)

⁵⁴ 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.

It is anticipated that where historical performance levels are considered inappropriate, it will usually be because of under-performance rather than over-performance. In such cases the ERC may decide to increase the performance target for a Regulated Distribution System to a level higher than that indicated by historical performance against an index. This may be done from the outset, or the improvement may be more gradually introduced over the third regulatory period, with new targets set for each Regulatory Year. Such changes from historical performance levels will only be made in exceptional cases, where performance levels are substantially and obviously inappropriate.

During the Second Regulatory Period the ERC intends to conduct an in-depth investigation into the actual service and network performance of Regulated Entities and international benchmarks in this regard. Based on its findings, it may then decide to base future incentive targets more on benchmarks than on historical performance, thus encouraging Regulated Entities to, where appropriate, further improve the quality of their service over time to internationally acceptable levels.

Over time, common performance targets will be established for all Regulated Entities. Given the significant differences between the Regulated Distribution Systems and the environments in which they operate, such common measures will require the setting of different performance targets for different network types.

9.4 Guaranteed Service Levels

The ERC will introduce a GSL scheme to Regulated Distribution Systems during the Second Regulatory Period. In terms of this scheme, Regulated Entities will compensate a consumer directly if certain service delivery performance thresholds are not met.

For the interim schemes proposed by Regulated Entities, the indices measured will be those suggested by them. From the third regulatory period onward, the indices described below will be used.

9.4.1 *Proposed GSL indices and payment levels*

The indices that will be included in the GSL scheme, and indicative performance targets against these, are listed below. Actual targets will be established during the course of the Second Regulatory Period and the indicative targets are by way of illustration only.

The proposed GSL measures, including indicative values for the thresholds are:

- a) GSL1 : a customer in an urban or sub-urban part of a Regulated Distribution System experiencing more than 15 hours of sustained interruptions over any Regulatory Year or a customer in a rural part of a Regulated Distribution System experiencing more than 25 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 15 sustained interruptions in a Regulatory Year or a customer in a rural part of a Regulated Distribution System experiencing more than 25 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 12 hours 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.

It is stressed again that the targets included above are indicative only and are not based on actual information submitted experience by Regulated Entities. Final targets will only be set once the appropriate data has been gathered from Regulated Entities.

9.4.2 *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 the Second Regulatory Period to determine the penalty levels that will apply when GSLs are not met.

The methodology that will be used to establish the penalty levels is as follows:

1. The ERC will calculate the total revenue allocation for the GSL scheme. As noted in section 9.3.4, this allocation will be calculated as 0.5 % of the allowed annual revenue, as calculated before the scheme is implemented. Since it is intended to set constant penalty levels for the whole of the Second Regulatory Period, these will be based on the revenue for Regulatory Year 2013 (the start of the Third Regulatory Period).

$$GSLRev = 0.005 \times ARR_{2013}$$

where ARR_{2013} is the allowed annual revenue for Regulatory Year 2013 calculated in accordance with clause 4.7.7 of the RDWR

2. Based on the data submitted by the Regulated Entities, the ERC will assess the likely number of instances in a year that each of the penalty levels will be exceeded. For example, the number of customers likely to have faults remaining after 12 hours (**GSL3**) during Regulatory Year t would be n_{GSL3} .
3. By allocating the same weighting to all the proposed GSL indices, the revenue allocation will be made per index. For example, the revenue allocated to the **GSL3** measure (restoration > 12 hours), assuming an equal weighting is allocated to each GSL index, would be :

$$GSL3Rev = 0.25 \times GSLRev$$

4. The penalty amount will be calculated by dividing the revenue allocation for each index by the estimated number of times that the penalty level for that index is expected to be exceeded. For example, the penalty payable each time that an interruption on the secondary side of a Regulated Distribution System is not restored within 12 hours, would result in a penalty amount of :

$$Pen_{GSL3} = \frac{GSL3Rev}{n_{GSL3}}$$

The weightings for each of the GSL indices may vary.

9.4.3 *Adapting revenue requirements*

During the Second 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.

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 will allow Regulated Entities the option to incur additional expense to avoid penalty situations, or to remain revenue neutral if they maintain current performance levels.

9.4.4 Reporting GSL performance to the ERC

The ERC requires each Regulated Entity to submit an annual report on its performance against the GSL indices. This report is to 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 of the second regulatory year and every regulatory year thereafter.

9.4.5 Improvement of service levels

As with the price-linked incentive scheme, the ERC intends to review the GSL scheme in depth over the Second Regulatory Period. During the regulatory reset for the Third Regulatory Period it may decide to, where appropriate, base GSL penalty levels more on local and international benchmarks for good practice than on actual performance, if such performance falls short of the benchmarks.

In addition, the ERC will at that stage :

- review the levels at which penalties have been set;
- review the threshold levels where penalties are incurred;
- consider the introduction of new GSL incentives or the removal of existing incentives that have proved to be inefficient; and
- may reconsider the total revenue component allocated to the GSL scheme.

The ERC will also at that stage investigate the possibility of placing a portion of the expected GLS revenue at risk, by excluding it from the allowed annual revenue for Regulated Entities.

9.4.6 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 intends to 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; and
- 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.

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.

The ERC will develop standard measures by which to assess whether the impact of an event was severe enough to cause the penalty to be disallowed.

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).

9.5 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;
- c) average forced-outage duration (total duration of forced outages divided by the number of such outages);

Service performance indices

- d) average time to respond to emergency calls;
- e) average time to respond to billing queries and complaints;
- f) average time to respond to payment queries and complaints;
- g) average time to reconnect a service after payment of all dues;
- h) average time to provide a complainant with a substantive answer to a complaint; and
- i) average time to correct a power quality complaint.

The information has to be collected and supplied to the ERC on a monthly basis. In addition to the monthly figures, the cumulative performance total against each index must also be provided, from the start of the corresponding calendar year till the end of the month for which each index was measured.

The ERC intends to annually publicize the information disclosure data for all Regulated Distribution Systems.

9.6 Measurement ability and details

It is essential that performance measurement information is both exhaustive and accurate.

It is required that all performance information submitted to the Commission is 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 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 information has been audited and found to be free of substantive errors and to represent a fair reflection of the performance of the Regulated Distribution System for the measurement year.

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 two such audits 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 ;
- 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.

9.7 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 is provided in Appendix J.

Monthly information should be submitted from October 2007. Submissions are required not later than the 20th of the following month.

10. 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 7.2 above.

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

10.1 Overview

The timetable for the annual rate setting process for an Application Year as described in the RDWR is set out in table 21 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 21 : 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 June preceding the Application Year |
| Submission of rate adjustment information and proposal for the wheeling rates to apply during the Application Year for each Regulated Distribution System by Regulated Entities to the ERC | June 30 preceding the Application Year |
| ERC to pass requests for further information to Regulated Entities | Before July 20 preceding the Application Year |
| Further information provided by Regulated Entities | Before July 31 preceding the Application Year |
| Regulated Entities to meet with ERC staff to explain the submission in detail | Before August 7 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 | August 21 preceding the Application Year |
| Implementation of the wheeling rates, if accepted by ERC in submitted form | October 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 August 21 preceding the Application Year |
| Public notification of amended wheeling rates | September 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 October 1 of the Application Year) |

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 9.3.2 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.

The rates submission has to be certified by the 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.

10.2 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. ($CR_{20YR} = \sum CR_{i,t+1}$)
- e) Determine the proportion of revenue to be recovered for each customer segment based on the projected revenue. ($\frac{CR_{i,t+1}}{CR_{20YR}}$)
- 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 March 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 rates 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.

10.2.1 Standardized rate structure

The ERC will develop a standard rate structure for all Regulated Entities for the Second Regulatory Period, in consultation with the Regulated Entities. This is to provide further guidance to Regulated Entities in the conversion of the MAP into standard customer categories and will also take into account problems associated with fixed amounts and demand components in tariffs, as well as the creation of tailored rates for large industrial consumers. The information on this structure will be provided to the Regulated Entities by September 17, 2007.

10.3 Side constraints

In terms of clause 6.4 of the RDWR, all maximum wheeling rates 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.

For the First Regulatory Year, this constraint is set at the CWI index plus 2 %. For later Regulatory Years, the constraint has not been predetermined and will be set by the ERC “having regard to the needs of End-users”.

The ERC will determine the side constraint factor once all the information for the regulatory reset process has been received. This will also take into account the intended new rate structure.

10.3.1 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. The adoption of the planned new general rate structure discussed above may also lead to unintended breaches of the side constraints. 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 accounted for (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 lay 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.

10.4 Introducing new rate structures

As noted above, the ERC intends to develop a standardized rate structure for all Regulated Entities before the start of the Second Regulatory Period. This will apply during the Second Regulatory Period.

10.5 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.⁵⁵

⁵⁵ See section 11.1 for a further discussion on these aspects

10.5.1 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 (currently set at 9.5%, but subject to change by the ERC), this will be to the account of the Regulated Entities.

11. OTHER ISSUES

11.1 Regulated pass-through events

In section 10.5 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.

11.1.1 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 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 11.3.

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 9.3.6) 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.

11.1.2 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 11.3 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.

11.2 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 serious enough to warrant a recalculation of the maximum average price caps or the X-factor.

11.2.1 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.

11.2.2 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 will 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.⁵⁶ Where such deferrals push projects out into a next Regulatory Period, it will be taken into account in the X-factor for that next 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. 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.

In recalculating 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. If the next Regulatory Year falls in the next Regulatory Period, the excess amount will be deducted from the allowed revenue calculated for the first Regulatory Year of the next Regulatory Period.

This calculation will also apply if the deferment of a Significant Project extends into the next Regulatory Period, in which case the X-factor will be recalculated for the next period, with the excess revenue subtracted from the allowed revenue for the next Regulatory Year of that Regulatory Period.⁵⁷

In many cases, deferred projects may still be required, even if more than 18 months after originally scheduled. In these cases the following approach will be used :

- If a Regulated Entity intends to continue with a deferred project during the same Regulatory Period in which it was originally included, it should inform the ERC of its intention as soon as it receives notice about the ERC's determination with regard to a delayed Significant Project, highlighting when it now intends to commence with the project. In such a case, the ERC will recalculate the X-factor for that Regulatory Period by considering the revised construction start date for the Significant Project in the capital expenditure and depreciation expense forecasts. The excess revenue earned up to the time of the recalculation of the X-factor will be deducted from the allowed annual revenue for the next Regulatory Year.
- If a Regulated Entity intends to continue with a deferred project, but only in the next Regulatory Period, the project should be removed from the capital expenditure forecasts for the current Regulatory Period and the X-factor for the remainder of the period recalculated, after deducting the excess revenue already earned by the Regulated Entity from the allowed annual revenue for the next

⁵⁶ Unless recalculated again in terms of events arising requiring such recalculation under Article XII.

⁵⁷ This is for situations where Significant Projects were scheduled to start within the last 18 months of a Regulatory Year.

Regulatory Year (which could fall in the next Regulatory Period). For the next Regulatory Period, the Regulated Entity should then re-include the project in their rate application as part of their capital expenditure forecast, where it will be treated the same as any other forecasted project.

The potential exists for Regulated Entities to defer capital expenditure approved under a Regulatory Period to the next Regulatory Period, even if expenditure is not delayed by 18 months. By including such expenditure again for the next Regulatory Period, the Regulated Entity will reap the benefit of having the expenditure approved in more than one period, without actually having had to incur it in the earlier period. To prevent this situation from arising, forecast capital expenditure approved in a Regulatory Period will not be re-allowed in the next period, unless a Regulated Entity requests the ERC to remove such a project from the capital forecasts for the current Regulatory Period, in which case the process described above will apply.

11.2.3 Major un-forecasted acquisitions

If a Regulated Entity makes major un-forecasted acquisitions during the Second Regulatory Period, it may lodge 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.

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 105% (or is less than 95 %) of the forecast value approved by the ERC for a Significant Project or the cumulative total of assets acquired during the Second 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 95% of the approved forecast.

The RDWR defines major acquisitions not included in the capital expenditure forecasts, as being more than the lesser of PhP 20 million or 0.1% 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 4.2.6., including the materiality levels described in clause 12.4.1(d)ii of the RDWR.

11.3 Procedure for events leading to an adjustment in rates

Recent 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 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.

11.4 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.⁵⁸ The definition of related parties is as per International Accounting Standard 24, and is summarized in Appendix B. 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.⁵⁹

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.

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;

⁵⁸ 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 3.1.1, 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.

⁵⁹ 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.

- 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 comes to the view 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 cost will be reduced to an efficient level by the ERC.

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.

11.5 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 Position 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 Position Paper.

In addition, it is important that in capturing their expenditure going forward, including their forecast expenditure for the Revenue Application, Regulated Entities separate out expenditure related to Distribution Connection Services.

It should be noted that in terms of the DSOAR, energy meters do not form part of Distribution Connection Assets and, to the extent that they are owned by Regulated Entities, these will therefore remain part of the regulated asset base under the RDWR, even if Distribution Connection Connections are separated out. (For the Contestable Market it may be possible that other parties may also own energy meters.)

11.6 Financial ratio analysis

In clause 4.22 of the RDWR, the requirement for the forecast financial statements and ratio analysis that each Regulated Entity must provide to the ERC is described. The ERC may retain a Regulatory Expert(s) to review and adapt these forecasts.

These forecasts are required for part of the economic and financial analysis that has to be conducted to determine the allowed annual revenue for a Regulated Entity. In particular it will be used to estimate the credit rating of a Regulated Entity, which will influence the determination of the building blocks for that entity.

It should be noted that these statements and ratios refer to regulatory accounts, not the actual financial accounts of Regulated Entities. The intention of preparing these forecasts are to provide the ERC with a clear forward picture of the impact of the PBR on the financial status of a Regulated Entity specifically with regard to the Regulated Distribution System(s) it manages. This would highlight any unintended anomalies or potential problems that may arise from the manner in which the maximum average price caps are set over the Regulatory Period.

11.7 Subtransmission Assets

In terms of Section 8 of the EPIRA and Rule 22, Section 13(b) of the IRR (implementing rules issues subsequent to the EPIRA), it is contemplated that Subtransmission Assets will be transferred from Transco to Regulated Entities. Where such Transferred Subtransmission Assets exist at the start of the Second 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 defined⁶⁰ 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 the purposes of this Position Paper, will be treated similarly to other Distribution Connection Assets.

⁶⁰ DSOAR, clause 1.2

12. PROPOSED FUTURE CHANGES TO THE RDWR

Although the regulatory reset process for the Second Regulatory Period for the Second Entry Point is now underway, the ERC wishes to signal its intention at this early stage about possible significant refinements that it may make to the RDWR at the next regulatory reset, before the Third Regulatory Period. These possible changes are flagged below.

12.1 Alternatives to the weighted average cost of capital

The WACC is traditionally one of the critical elements to be determined during a regulatory reset for any form of regulation relying on building blocks or a return on rate base. It is also an element for which the underlying components are hard to determine and which are subject to a great deal of debate and contrary interpretation. Especially in an environment like the Philippines, where there is relatively little trading in public equity and liquidity levels are low, it is very hard to observe the WACC parameters. It therefore becomes necessary to rely on international figures, which introduce further elements of uncertainty, and may not always be appropriate.

In view of these problems, the ERC intends to investigate alternative means of determining the appropriate cost of capital that should apply to Regulated Entities. This may include :

- establishing an accurate risk-free rate for the Philippines and adding an appropriate margin to that rate to compensate investors in electricity distribution businesses for the risk they face above this rate; or
- consideration of the level at which a large Philippines corporation with an assessed credit rating equivalent to an electricity distribution business can obtain capital and the return that it expects to achieve on its equity.

Such measures will by definition involve simplifying assumptions but, given the uncertainties surrounding the WACC and the CAPM on which it is based, may still be more appropriate, especially if wide consensus can be reached among Philippine utilities that the assumptions are reasonable.

12.2 Standardized customer segmentation and rate structure

It is an ideal of the ERC to assess and compare the relative performance of Regulated Distribution Systems right throughout the country on a common basis and to ensure that customers in similar environments receive similar service levels at similar price levels.

To achieve this, the ERC intends to undertake studies during the Second Regulatory Period to look at the standardization of Customer Segments across Regulated Distribution Systems and non-regulated distribution systems.

This will also be incorporated into a study that the ERC will conduct on the creation of a standardized rate structure for Distribution Utilities under PBR. (See section 10.2.1.)

12.3 Improved performance incentive scheme

The ERC intends to further improve the performance incentive scheme. It therefore intends to conduct further studies during the course of the Second Regulatory Period. At

the same time, the ERC intends to collect more actual performance data on a variety of measures.

Particular aspects that will be investigated include :

- the cost (capital and operating) to improve various service levels;
- the variability in Regulated Distribution System performance against each performance index and establishing appropriate mean performance levels and acceptable limits of variability;
- the importance attached by customers to the various performance incentive indices;
- the cost of un-served energy for various customer types; and
- the willingness of customers to pay more for improved service levels.

12.4 Regulatory accounts

It has been noted that the financial accounts and ratio referred to in clause 4.22.2 of the RDWR are regulatory accounts, not the company's standard financial accounts. The ERC intends to further develop the reporting requirements for these regulatory accounts to ensure that they are prepared to the same standard as the standard financial accounts and can be:

- independently audited as per standard accounting and auditing procedures; and
- reconciled with the Regulated Entities' standard financial accounts.

12.5 Frequency of asset re-valuation

The ERC will investigate the feasibility of foregoing a formal asset re-valuation as described in clauses 4.8 and 5.5 of the RDWR for one or more of the Subsequent Regulatory Periods. Instead, the opening value of the Regulatory Asset Base at the start of the Third Regulatory Period may be based on the value of the Rolled Forward Depreciated Asset Base, after applying an appropriate inflation and foreign exchange index to account for the period since the last formal re-valuation.

Given that :

- an optimized replacement cost for the Regulatory Asset Base will be formally established at the start of the Second Regulatory Period;
- all future capital expenditure will be approved by the ERC and will only allow for optimized assets; and
- depreciation will be in accordance with standard asset lives,

it is anticipated that the asset value at the start of the Third Regulatory Period as determined through a re-valuation process as described in sections 4.8 and 5.5 of the RDWR, will not differ substantially from the indexed value of the Rolled Forward Depreciated Asset Base at that same date.

This assumes that the valuation and optimization process accepted for the final determination of the maximum price cap will remain the same for the Third Regulatory Period.

Pasig City, March 14, 2007.

RODOLFO B. ALBANO, JR.
Chairman

ALEJANDRO Z. BARIN
Commissioner

RAUF A. TAN
Commissioner

MARIA TERESA A.R. CASTAÑEDA
Commissioner

JOSE C. REYES
Commissioner

APPENDIX A : OPTIMIZATION PRINCIPLES

In this section, the guidelines for the optimization of network assets are provided.

A1. Introduction

The intention of optimization when valuing a distribution network is to ensure that the network would use the most cost-efficient design that would provide the required service potential. In theory such a state could however only be achieved if an approach is followed that completely disregards the design and configuration of the existing asset base. Such an approach would be cost intensive and is likely to result in variable and inconsistent outcomes.

The form of optimization proposed for the ERC therefore uses the existing network as the starting point for the valuation. A series of optimization tests must be systematically applied to the whole network to identify stranded assets, excess capacity and over-engineering. Where necessary, the network is notionally redesigned to provide an optimized network.

Optimization is to be undertaken after the replacement cost (RC) distribution network has been determined. The output from this process is the optimized replacement cost (ORC).

The base rules for establishing the optimized network are that it should:

- a) provide a quality of supply similar to that which currently exists, except where this exceeds the approved standard quality of supply criteria; and
- b) have a capacity similar to that of the existing network, except where this exceeds allowed future load growth.

Optimization consists of five stages:

- a) excluding stranded assets;
- b) optimizing the configuration of the network;
- c) optimizing the capacity of elements in the network;
- d) optimizing network engineering; and
- e) optimizing stores and spares.

The determination of indexed historical costs, replacement costs or modern equivalent replacement costs for existing individual network components is *not* part of the optimization process. This shall be done prior to calculating the RC.

A2 Life cycle analyses

As a general rule, optimization will involve the selection of the lowest cost asset that would provide the required capacity and service levels at a particular point on a distribution network. However, the most cost-efficient design is the one that minimizes the present value of the total costs of an asset and its use over its standard lives (or maximizes the present value of an asset). The situation may therefore arise where the use of a lower cost asset is avoided because of such life cycle cost analysis. In such cases, a general description of the analysis and assumptions used should be included in the valuation report.

In undertaking life cycle cost analyses to determine the most efficient design, the following may be taken into account:

- (i) the capital and operating costs over the life of the asset;
- (ii) other costs that are incurred by the Regulated Entity as a result of the use of the asset; and
- (iii) the cost of losses to the extent that these are caused by the existing load and the allowed future load growth.

A3. Constraints on Optimization

The optimization process shall be carried out subject to the following constraints:

- a) the potential level of service of the optimized network shall not exceed that of the existing network, and the performance of any part of the optimized network shall not exceed the Regulated Entities disclosed quality of supply criteria, unless nonstandard contracts with customers exist that require the Regulated Entity to provide an enhanced quality of supply;
- b) the location of points of connection to other networks should be assumed to be fixed. However, where a point of connection can be bypassed and replaced with a more cost-efficient network arrangement, then that point of connection shall be deleted for valuation purposes;
- c) the location and number of connection points to consumers should be assumed fixed;
- d) the optimized network should only use the voltage levels used on the existing network; and
- e) the existing geographic boundaries of the Regulated Entity's supply area should be assumed to be fixed.

A4. The Process of Optimization

Optimization of the network shall be undertaken on a systematic basis. The optimization process must examine the existing network and determine whether a more cost-efficient design could meet the required quality of supply criteria throughout the allowed planning period. Optimization shall be undertaken systematically across the network and shall include, in particular, the following network components:

- a) points of connection to other networks;
- b) substations and primary distribution switching stations;
- d) subtransmission lines and primary distribution circuits;
- e) high voltage distribution feeders; and
- f) the low voltage distribution system.

A5. Future Load Growth

The maximum capacity of any part of the optimized network shall be determined by the allowed future load growth, which is the maximum forecast load on the relevant part of the network under contingency operating conditions over the allowed planning period. However, in no case shall optimized capacity exceed existing capacity.

In order to ensure compliance with this clause, when preparing valuations Regulated Entities shall disclose both existing loads and the load forecast used as a basis for optimization. As a minimum, existing and forecast loads shall be provided for each grid connection point, each main substation and each high voltage distribution feeder. Clear justification and a detailed derivation of the load growth forecasts are required. Both the existing maximum demand and the highest forecast maximum demand during the planning period shall be provided.

Allowances should be made, where possible, for different growth rates in different parts of the network. Existing loads may be estimated where metering is not available.

The load forecast shall include only future electricity loads that can reasonably be expected to be supplied from the distribution network. A load outside the existing geographic boundaries of a Regulated Entity's area of supply shall not be included in the forecast unless a written customer contract to supply the load exists at the time of the valuation.

The planning periods over which future load growth can be allowed for shall not exceed the following:

- a) for subtransmission lines, substations (excluding transformers), primary distribution circuits and points of connection to a transmission network, 15 years;
- b) substation transformers, 10 years;
- c) high voltage (HV) and low voltage (LV) distribution, and other network assets, 5 years.

A.6 Quality of Supply

The optimized network shall be designed to supply the existing load, and the allowed future load growth, with a quality of supply that matches the level that currently exists for each part of the network, except where this is greater than the quality of supply criteria as approved by the ERC.

For the optimization process, Regulated Entities shall disclose the quality of supply criteria that it currently uses as a basis for network design. This should be based on their analysis of customer requirements and assessment of network maintenance requirements and costs.

Relevant quality of supply criteria include:

- a) the degree of security (redundancy) in different circumstances or localities;
- b) target reliability indices for different areas of the network (CBD, urban, rural);
- c) voltage regulation criteria; and
- d) levels of electrical losses.

The degree of security may be disclosed either in probabilistic or deterministic terms. A deterministic approach could reference the level of in-built redundancy, i.e. as (n) or (n-1) or (n-2) component redundancy. (An (n) security level implies no component redundancy so that if a component fails, then customer supply is lost. An (n-1) security level is one in which customer supply is not interrupted in the event of any single component outage etc.) Irrespective of whether probabilistic or deterministic criteria are used, it is necessary for a Regulated Entity to express its degree of security criteria in such a way that the optimization process is transparent and can be shown to have been applied consistently across all parts of the network.

Existing Distribution System assets that provide a quality of supply greater than that disclosed by the Regulated Entity shall be optimized out, except where the assets are required to meet contractual obligations to provide an improved quality of supply to specific customers.

A7. Excluding Stranded Assets

Any system fixed assets not required to supply line services to existing customers, and which could therefore be disconnected, shall be identified and excluded from the optimized network. Such assets are known as stranded assets and should be optimized out.

A8. Optimizing System Configuration

Optimization of the system configuration shall be carried out by considering alternative configurations subject to the constraints on optimization and in accordance with the relevant criteria relating to the quality of supply declared by the Regulated Entity. The optimized configuration is the one that satisfies the relevant optimization criteria in the most cost efficient manner.

In the process of optimizing the system configuration, certain assets or groups of assets may become excess to requirements and should be valued at nil, while other new assets may need to be notionally brought in.

A9. Optimizing Network Capacity

After the configuration of the system has been optimized, the elements within that system shall be optimized by considering whether lower capacity, more cost-efficient elements would be adequate.

Civil engineering works such as spare ducts, cable tunnels and switchyard bays not currently used shall be optimized out unless they will be required to meet the allowed future load growth. If the future use of such assets is only intended to provide an improved quality of supply, rather than an increase in system capacity, the assets shall be optimized out since the optimized system shall not provide a quality of supply greater than that which currently exists.

A10. Optimizing Network Engineering

As part of the process of optimizing the network, the engineering of the network shall be examined to confirm that the optimized asset base is not over-engineered, given the required quality of supply criteria. Over-engineering may occur if parts of the existing asset base are engineered to a standard that exceeds the Regulated Entity's current practice or if a more cost-efficient engineering arrangement or configuration would be used if the existing assets were replaced. The Regulated Entity's design and construction standards, and the standard of engineering applied to its most recent projects should be used as the benchmark for this test. Where a more cost-efficient arrangement would result if the required level of service were provided by applying the Regulated Entity's existing engineering standards then the relevant assets shall be replaced by a notional asset arrangement that reflects current practice.

A11. Optimizing Network Equipment Spares

Network equipment spares may be included in the ORC valuation as long as the spares are suitable replacements for assets installed in the network. However, the quantity of spares in valuation shall not exceed the reasonable quantity of spares required to meet the Regulated Entity's disclosed quality of supply criteria.

Stranded assets may be valued as network spares, subject to the criteria set out above. Stranded assets not required as network spares shall be assigned a zero value for the purposes of the valuation.

A.12 Assets to be Included in the ORC Valuation

Only fixed assets forming part of a Regulated Distribution System owned by a Regulated Entity or subject to a finance lease are to be included as part of the optimized replacement cost of the Regulated Distribution System. Such fixed assets are assets that are tangible in nature, have relatively long useful lives, and are used, or intended to be used, for the conveyance or supply of electricity. Where an easement forms an integral part of a network asset, it should be considered to be a system fixed asset and may be included in the valuation. Stores and spares held in stock that can be used in the network in place of existing network assets may be included in the valuation to the extent that the quantities of items included in the valuation are appropriate, considering the historical reliability of the equipment and the number of items installed on the network.

The following assets shall not be included in the ORC valuation:

- a) office buildings, except where required for the real time operation and control of the distribution or transmission network;
- b) depots and workshops;
- c) office furniture and equipment;
- d) motor vehicles;
- e) tools, plant and machinery;
- f) works that are under construction;
- g) non-network related land;
- h) non-network related stores and spares;
- i) computer systems, except computer systems that are used for real time network operation and control;
- j) asset management systems, including geographic information systems, except where such systems are used for real time network operation and control;
- k) street lights and poles or other structures used exclusively for the support of streetlights;
- l) street light control relays and circuits or other equipment used exclusively for the control of street lights; and
- m) assets where the ownership is disputed or unclear.

To avoid any uncertainty, it is noted that assets not forming part of the optimized replacement cost of Regulated Distribution System would still be considered part of the Regulatory Asset Base, in as far as they are used to support the provision of Regulated Distribution Services.

In addition, it should be noted that non-system assets found to be surplus to the efficient operation of a Regulated Entity, may also be excluded from the opening valuation of the Regulatory Asset Base.

APPENDIX B : RELATED PARTY TRANSACTIONS

Related party transactions and the obligation of disclosure by Regulated Entities of such transactions are described in section 11.3 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.

B1. 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.

B2. 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
- Settlement of liabilities on behalf of the entity or by the entity on behalf of another party

APPENDIX C : EXPLANATION OF O&M COST CATEGORIES

The UFR identified the following categories and sub-categories of OPEX:

414-000-00 DISTRIBUTION EXPENSES

414-000-10 Operation

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.

414-581-10 Operation – Load Dispatching

This account represents the expenses incurred in load dispatching operating 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.

414-582-10 Operation – Station 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 Line Expenses

This account represents the expenses incurred in the operation of distribution lines.

Included in this account are salaries and wages in supervising line operation, changing line transformer taps, inspecting and testing lighting arresters, line circuit breakers, switches and grounds, inspecting and testing line transformers for the purpose of determining load, temperature or operating performance, routine patrolling of lines, load

test and voltage surveys of feeders, circuits and line transformers, removing line transformers, oil circuit reclosers and sectionalizers with or without replacement, installing line 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..

414-585-10 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 operating, 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).

414-588-10 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.

Information technology (distribution network related)⁶¹

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,

⁶¹ This is a new requirement for the Position Paper and therefore does not have a corresponding rate filing identifier

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 – Structures

This account represents expenses incurred in the maintenance of structures, the book cost of which is includible in the sub-account Structures and Improvement under the plant 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 a retirement unit.

414-592-20 Maintenance – Station Equipment

This account represents expenses incurred in maintenance of plant, the book cost of which is includible 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.

414-593-20 Maintenance – Overhead Lines

This account represents expenses incurred in the maintenance of line distribution facilities, the book cost of which is includible 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 platform, 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 devices 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, going 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, retying service line, and refastening or tightening service bracket.

414-593-20 Maintenance – Line Transformers

This account represents expenses incurred in maintenance of distribution line transformers, the book cost of which is includible 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.

414-596-20 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 is includible 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.

Information technology (distribution network related)⁶²

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.

Maintenance – Meters

This account represents expenses incurred in maintenance of Distribution System meters and associated installations, and meter testing equipment.

414-598-20 Maintenance – Miscellaneous Plant

This account represents expenses incurred in the maintenance of miscellaneous plant, the book cost of which is includible 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.

ADMINISTRATIVE AND GENERAL EXPENSES

430-920-00 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.

430-921-00 Office Supplies and Expenses

This account represents expenses incurred for office supplies and expenses incurred in connection with the general administration of utility's operating 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

⁶² Supra note 61

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.

Information technology (admin & general)⁶³

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.

430-923-00 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.

430-924-00 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.

430-925-00 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

⁶³ Supra note 61

or others for expenses charged hereto on account of injuries and damages and insurance dividends or refunds.

430-926-00 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.

430-927-00 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, solicitors, 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 of 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.

430-931-00 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.

430-932-00 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.

430-933-00 Taxes on Property

For this Position Paper and the RDWR this is covered under the “levies, duties and taxes (other than corporate income tax)” category.

430-934-00 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.

430-935-00 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.

430-936-00 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.

430-936-00 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 Act (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); and
- 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;

(Items [a] to [e] – identified under Section 2.10.4 of the WESM Rules)

- 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.

CONSUMER ACCOUNTS EXPENSES (REGULATED RETAIL SERVICES)

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.

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.

420-902-00 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.

Information Technology (consumer related)⁶⁴

Consumer related IT systems are those dedicated to providing and supporting customer services, including Distribution Connection Services.

420-903-00 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 operating, 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

⁶⁴ Supra note 61

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.

420-904-00 Uncollectible Accounts (Bad debts)

This account represents provision for losses arising from uncollectibility 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.

420-905-00 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.

420-06-00 Miscellaneous Consumer Services Expenses

This account represents the expenses incurred in connection with consumer service and informational activities which are not includible 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.

420-907-00 Consumer Prompt Payment Discount

This account represents discount given to consumers for paying bills on time. Included in this account are discounts availed by consumers. (Note that this provides for discounts on that portion of the invoice associated with distribution wheeling services only.)

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 as 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 D : 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.

D1. 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.⁶⁵

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 9.3.6 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.⁶⁶

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 conformance 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 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

⁶⁵ These definitions correspond as closely as practical with those in the Philippines Distribution Code and the IEEE standard 1366-2003 (IEEE Guide for Electric Power Distribution Reliability Indices)

⁶⁶ 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.

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.

D2. Price-related incentive scheme

D2.1 SAIFI

Definition : System average interruption frequency index of 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 with 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.

- iii. 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.
- iv. Interruptions arising from Excluded Events are not to be taken into account in calculating the SAIFI.

D2.2 CAIDI

Definition : Customer average interruption duration index of 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 with 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.

D2.3 Planned SAIDI

Definition : System average interruption duration index (for Planned Interruptions) of index

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 with 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.

D2.4 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 :

$$pV_v = \frac{\text{Number of voltage violations encountered}}{\text{Number of long duration voltage readings taken}}$$

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.

D2.5 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,⁶⁷

SL = Total technical and non-technical system losses (measured in %) over the Measurement Period

UI_t = The total MWh⁶⁸ 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.⁶⁹

- 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.

D2.6 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,

⁶⁷ 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 Act (Republic Act no 7832).

⁶⁸ Where more appropriate GWh can be used as the measurement unit for this index

⁶⁹ Note that this figure includes those units delivered to end users that are not paid for, resulting in bad debts.

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 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 to when the required response is obtained,⁷⁰ 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.

⁷⁰ Which could include the final rejection of the application, resulting in the inability of the Regulated Entity to provide the required service.

D2.7 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 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 manmade 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.

D2.8 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, till 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.

D3. Guaranteed Service Level incentive scheme

D3.1 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.

D3.2 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.

D3.3 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), till 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).

D3.4 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.

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 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.

D4. Information disclosure

Network performance indices

D4.1 MAIFI

Definition : Momentary average interruption frequency index of index