REGULATORY TREATMENT OF ELECTRICITY SYSTEM LOSSES IN JAMAICA: WHAT IS FAIR?

Paper to the 3rd Organization of Caribbean Utility Regulators Conference,
November 2 - 4, 2005, Nassau, Bahamas.

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[1] The views expressed in this paper are strictly those of the author and should not be ascribed to the organization to which he is employed.

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ABSTRACT

In Jamaica, like in many other developing countries, there is a long history of practice where many electricity consumers do not pay for the service. The Jamaica Public Service Company (JPS), the sole transmitter and distributor of electricity in Jamaica, intensified its efforts to address this problem when they instituted a centralised unit in 1999 with the sole mandate of reducing the system losses, which includes both technical and non-technical losses, the later being predominantly electricity theft. In recent times however the system losses has risen to significantly high values and it seems as if the utility has reduced its efforts in addressing the issue. The centralised unit that was set up to tackle the problem was eventually dismantled. In the face of this, many believe that there is not adequate financial incentive being given to the utility to reduce losses for the reason that it is allowed to pass on a considerable portion of its losses to its customers. This paper will examine the regulatory treatment of losses in Jamaica and will seek to explore the issue of what is a fair distribution of the cost associated with system losses between the utility and customers, by proposing alternative regulatory mechanisms. The regulatory treatment of system losses in other countries will also be presented with the aim of establishing useful comparisons.

Keywords: regulatory treatment, electric utility, system losses, incentives

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1. INTRODUCTION

Electricity loss is an inevitable and natural aspect of the electricity utility business. The flow of electricity around an integrated electric network causes losses in the various elements of the network. Most of these losses are a function of the current flowing through the circuits, causing heating of conductors, transformer windings and other devices. These losses are typically referred to as “variable losses” and are roughly proportional to the square of the currents through the elements. In addition to these variable losses there are also “fixed losses” in the lines and transformers, which are not a function of the current.[2] The sum of these variable and fixed losses is collectively termed “Technical losses”.

The total system losses incurred by the electric utility come from two main sources: *(1) technical losses* - which was described in the previous paragraph and *(2) non-technical (or commercial) losses* – which are associated with inadequate or missing revenue metering, with problems with billing and/or collection systems, and/or with consumer pilferage. Compared to developed nations, developing countries have always had higher system losses. For most of these developing countries, the non-technical component of the system losses is usually significant [9]; for example, the non-technical losses for Jamaica are for the most part over half the total system losses. The following table gives an indication of the actual levels of system losses that is experienced by utilities in the Caribbean region:

Country	**System Losses**
Trinidad and Tobago	6.9% (2003)
Jamaica	19.9% (2004)
Guyana	44% (2004)
Grenada	8.7% (2001)
St. Lucia	10.2% (2004)

Table 1: System Losses for some Caribbean Electric Utilities

[2] Fixed losses in overhead lines take the form of corona losses, which are a function of the voltage levels and weather conditions (for example temperature and humidity). Corona loss refers to the loss of power to the air and insulation surrounding high voltage equipment. Fixed losses in transformers take the form of core losses. Core losses occur in the iron core of the transformer as a result of heating in it when subjected to an alternating magnetic field.

In general, system losses increase the operating costs of electric utilities and typically result in higher cost of electricity.[3] In [2] it was estimated that on average, electricity losses in South Africa added 6-8% to the cost of electricity and some 25% to the cost of delivery.

The reduction of system losses in any utility is important because of its economic, financial and social repercussions for the electric utility, the customers and even the operating country. System losses by and large pose a major challenge for regulatory agencies. Depending on the regulatory arrangement, losses can have adverse and varying levels of financial effects on the customers and the utility. On one extreme, if the utility were allowed to pass through its entire loss to the customers, irrespective of the magnitude of this loss, there would be no incentives for it to enact loss reduction measures. This may not be fair to the customers because certain operating inefficiencies of the utility that impacts the system losses could be passed on to them. On the other extreme it would be unfair for the utility to shoulder all the responsibility of the system losses because: *(1)* as was previously mentioned, some amount of losses are inevitable in the transmission, distribution and supply of electricity to consumers and the utility must be allowed to at least recover its necessary costs in providing its service, and *(2)* it would not provide the right price signals to customers about the true cost of supplying electricity. Obviously then, some equitable balance must be found by the regulatory agency so that the utility has an incentive to implement loss reduction measures and there are mutual benefits to be gained by the utility and the customers on account of loss reduction.

This paper will evaluate the regulatory treatment of system losses in Jamaica and will propose an improved regulatory mechanism for such losses, which in the author's opinion is more equitable than the current arrangement. In doing so, the current regulatory arrangement will be examined in detail. Other regulatory structures worldwide will be discussed with the aim of providing useful ideas for the Jamaican case.

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[3] The increase in the electricity price to customers will depend on the regulatory treatment of the losses in the tariff.

2. REGULATORY TREATMENT OF ELECTRICITY LOSSES

2.1 **General Approaches**

In this section, the general approaches to regulatory treatment of electricity system losses will be discussed.

According to [10], regulatory mechanisms for reducing technical and non-technical losses can be grouped into two broad (but not entirely distinct) categories:

1. Command-and-control rules
2. Incentive Based

Command-and-control rules, in general terms, prohibits or discourages the utility from undertaking a specified objectionable practice by the threat of a monetary penalty. An incentive based approach, in comparison, attempts to change a utility's behaviour through explicit monetary rewards and penalties across different levels of actual performances. Under the threat of a penalty or sanction, as is the case for a command-and-control rule mechanism, the utility faces a dichotomous choice: receive a specified amount of revenue when attaining the targeted levels of losses or receive fewer revenues when failing to do so. Under an incentive based mechanism the utility will recover a different share of its actual cost depending on the magnitude of actual losses [10].

Juris [5] articulated that in order to apply either the command-and-control rules or the incentive based mechanisms; the regulatory approach should be to first carry out the following due diligence exercises:

- Settle on the loss measurement method
- Monitor (measured or estimated) losses over time: a statistical measure of losses would provide information on their severity.
- Establish losses targets: for the technical losses target, this task is implicitly an economic cost/benefit study identifying the level of technical losses at which the

> utility cost of service would be at a minimum.[4] Targeted losses however could reflect what a regulatory agency considers reasonable utility actions over some specific period of time.

In his paper presented at the 1st Energy Regulation and Investment Conference for Central/Eastern European (CEE) Regulators, Juris [5] examined various loss levels that could be allowed in tariffs. The first loss level scheme he identified was one which allows all the actual losses to pass through to the customers in the tariff. However, he highlighted that the major disadvantage of this method is that there is no incentive by the utility to reduce losses. He next identified a scheme in which the loss that is allowed to pass on to customers is equal to a loss target that has been established by the regulatory agency. This loss target is generally less than the actual system losses and the utility has an incentive to minimize its losses. The disadvantages that were identified for this arrangement are that it is difficult to set reasonable loss targets and it creates a challenge to implement when the established loss target is way off from the actual system losses. While Juris [5] recognized the disadvantages of the loss target method, he gave a prescriptive approach to mitigate against these disadvantages. He pointed out that quantitative loss levels and loss reduction schedules should be set based on the best information available[5] and proposed that a moving target be defined e.g. based on the average loss from the last year and the last three years. These average losses could then be used to adjust tariff loss levels in each year by a loss index that could be calculated as follows:

$$LossIndex = \frac{\Delta_T}{\Delta_L} = \frac{ThreeYear\ Average - Year\ Loss}{LastYear - Year\ Loss} \qquad (1)$$

In the above equation, a loss index is computed as the ratio of Δ_T and Δ_L where Δ_T is the difference between the average loss over the last three years and the current loss and Δ_L is

[4] Although lower technical losses, by and in themselves, would lower a utility's cost, expenditures required to achieve lower losses might drive up the utility's overall cost.

[5] The best information available speaks to historical losses trends, prior loss reduction initiatives by the utility and their results, and an understanding of the loss levels that would reflect the utility's proper operating practices.

the difference between last year's loss and the current loss.

The final scheme proposed in [5] is a more sophisticated scheme than the previous two. In this scheme, the allowed target loss level is set, but rather than passing all of this loss on to the customers at once, an acceptable loss level is included in the tariffs now, and the recovery of the remaining cost is postponed until after a transitory period. The cost associated with the remaining losses is included in what is termed a "Regulatory Asset".

A regulatory asset was defined in [5] as a promise by the regulator that deferred costs will be included in tariffs in the future. It is a transition mechanism used during a period when it may not be prudent for tariffs to recover the total cost. Instead of recovering the total cost at once, a part of it (the regulatory asset) is amortized gradually and a return is earned by the utility on this cost until it is fully amortized. The cost of financing the regulatory asset can be recovered from the tariffs or capitalized in the regulatory asset. Juris enunciated in his paper that regulatory directives for a multi-year loss reduction plan for the utility are crucial for the success of this scheme.

To illustrate how the regulatory asset approach works the following example will be used:

Consider a case where the allowed target system loss is set at 20% and that 15% is allowed to be recovered immediately and 5% in the future. In this case the regulatory asset is 5%. A regulatory agency could include a multi-year loss reduction plan in which the system losses go down by 1% over the next five years (transition period) and the regulatory asset is to be recovered over the following ten years (post-transition period). The following graph shows the balance and payments of the regulatory asset for the example.

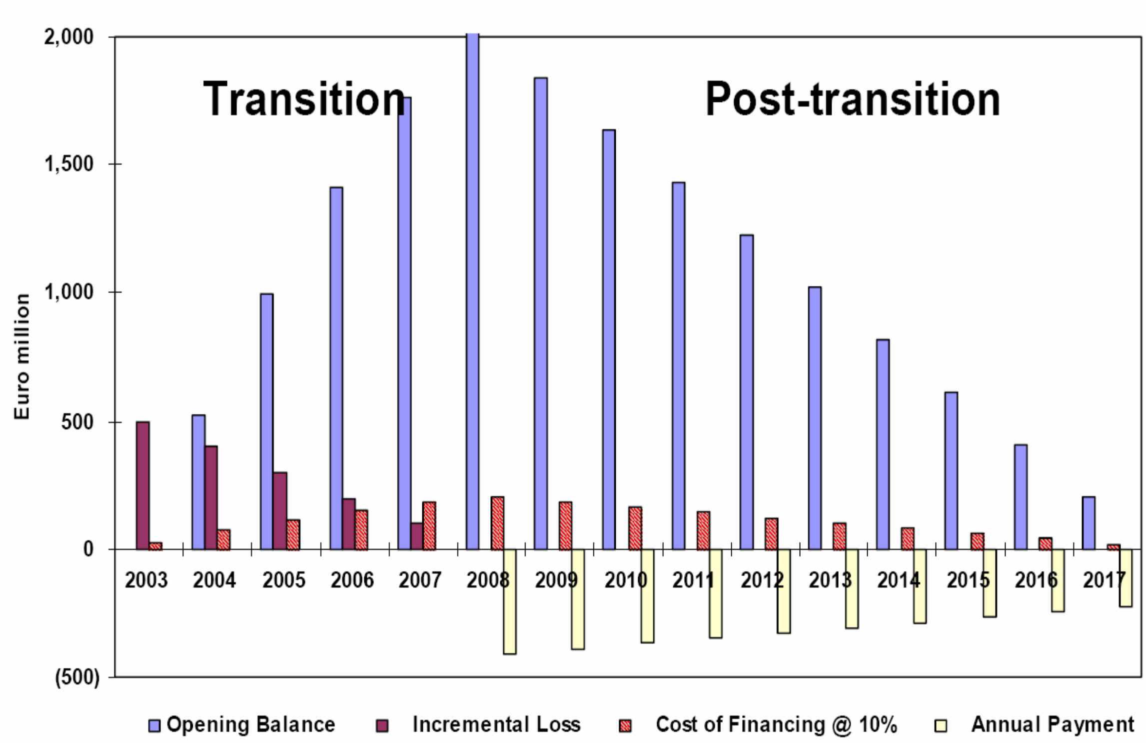

Figure 1: Regulatory Asset: Balance and Payments
Source: "Regulatory Treatment of Energy Losses: Alternate Approaches" [5]

According to Juris [5], the benefits of the regulatory asset scheme are:

- Costs can be deferred until a period when tariff increase may be more acceptable for (e.g. when efficiency and reliability have improved)
- Companies will continue to earn a reasonable return on investment of deferred cost (subject to regulatory adherence to the plan)

There are however some disadvantages to the regulatory asset method of loss level tariffs. The method hinges on the willingness of future regulators to honour the deal. The risk of a regulatory default increases the longer the cost recovery is deferred. Another disadvantage is that tariffs will be higher in the future than they otherwise would have been. However, this may be a form of inter-generational equity; since future generations will get the benefit of lower losses, it therefore seems fair that they assist in paying for this loss reduction.

2.2 Regulatory Treatment of System Losses in Some Countries

In the United States the typical regulatory treatment of technical losses in rates involves customers being charged for only a reasonable amount of line losses as preset by the Commission [10][6]. To assure consumers that they are not overpaying, the Commission periodically revisits the pre-set line losses. This pre-set loss level is used in an incentive based scheme in which the utility is penalised if its technical losses exceed the pre-set level. If a reduction in line loss below the Commission's pre-set level is achieved, the utility receives a greater margin from existing rates. The allowable line losses are typically charged to all customers, including transportation consumers and not merely the utility's own ultimate sales consumers. Each state Commission sets technical losses at a level it considers reasonable and is based on historical losses as well as the Commission's understanding of what is technically achievable, given the utility's own unique network.

The United States has a very interesting way of treating commercial losses. It distinguishes commercial losses, which are due to inadequate or missing revenue metering, with problems with billing and/or collection systems and with pilferage, from those associated with non-payment of bills. The typical rate treatment for those in the former category is to simply place the distribution entity totally at risk for a failure to recover these kinds of commercial losses. Commercial losses arising from non-payment of bills are recovered from other customers or from direct government subsidies. Those commercial losses arising from customers who can afford to pay for electricity is normally recovered from other customers. The government, however, subsidies losses that are incurred by customers who are deemed unable to pay the full cost of their electricity bill.

In the former Soviet State, Georgia, the utility is only allowed to recover costs associated with technical losses in the tariff. This is an incentive for the utility to significantly reduce commercial losses. The country had a very high loss level; at the time of privatisation of the utility, the sum of the commercial and technical losses stood at around

[6] The pre-set loss level may be different for each State/Region

40%. The commercial loss was a significant proportion of the 40% loss level. Ukraine's regulatory treatment of system losses is similar to Georgia's [10], that is, only cost associated with technical losses is applied in the tariff (commercial losses are not reflected in the tariff).

The typical approach to system losses in many South American countries (for example, Argentina), which had high levels of system losses, was to pass on all the cost to the paying consumers.[7] However, subsequent deregulation in a number of these countries has led to substantial reduction in system losses [9].

3. REGULATION OF SYSTEM LOSSES IN JAMAICA

The main focus of this section is to present and analyse the regulatory treatment of system losses in Jamaica. The section however will begin with a description of the Jamaica Public Service Tariff Structure. A description of the JPS Tariff Structure is necessary for understanding the context in which the regulatory treatment of losses is applied.

3.1 JPS tariff Structure

The Jamaica Public Service Company is a vertically integrated utility and has sole responsibility for the transmission, distribution and supply of electricity to Jamaican consumers.

The Jamaica Public Service Company tariff, as set by the Office of Utilities Regulation, the regulatory agency for utilities in Jamaica, consists of three components:

- A Non-fuel based rate
- A Fuel based rate
- An Incremental Independent Private Producer (IPP) surcharge

[7] The thought was that losses (commercial) arose because of social problems and was not within the utility's control

The non-fuel based rate is the primary component of JPS' tariff and was designed to recover the non-fuel revenue requirement for JPS to provide its service. The non-fuel revenue requirement includes prudent non-fuel operating costs including the estimated IPPs non-fuel based costs, depreciation expenses, taxes and a fair return on investment. The non-fuel based rate is controlled by a Price Cap regime. Under this regime, caps on the prices are set for a five-year period (2004-2009). Specifically, price is set in the first year (the test year), based on the revenue requirement highlighted above. Going forward the price will be adjusted for [7]:

- Inflation and exchange rate movement
- Expected efficiency gains based on differentials in productivity trends between JPS as well as the United State and the Jamaican economies; and
- A bonus or penalty based on JPS performance on selected quality of service parameters.

The fuel-based rate relates to the cost of the total fuel consumed by JPS and the IPPs in the production of electricity. It is computed as the cost of fuel per kilo-watt hour (kWh) of energy sales (net of efficiency targets). Consequently, fuel cost (net of efficiency) is directly passed through to the customers.[8]

The IPP surcharge relates to the actual total contractual cost obligations that JPS has based on the IPPs' power purchase agreements with JPS, less the estimated non-fuel based IPP charges (captured in the non-fuel base rate)[9] and the IPPs' total fuel costs (captured in the fuel base rate). The charge is computed as this net cost divided by the kilo-watt hour (kWh) energy sales. This implies that the IPPs' actual costs are also directly passed on to the customers.

[8] The efficiency parameters that affect the fuel-based rate are the system losses and the heat rate of the system.

[9] In built in the non-fuel base tariff is the estimated IPP non-fuel based charge.

3.2 OUR's treatment of System Losses

To understand how OUR treats systems losses for JPS it is important to identify how these losses are captured in the various tariff components previously identified. This will be done here.

The non-fuel based revenue requirement can be depicted by three principal cost causation components:

- **Energy**:- cost which vary with the consumption of energy (variable costs including variable O&M)
- **Demand**:- cost which vary with the capacity requirements of the customers (fixed cost of generation, transmission and distribution investments).
- **Customers**:- cost which vary as a function of the numbers of customers served (fixed cost of meters, service lines etc.).

To compute the non-fuel based rate, the energy component was divided by the total kWh sales (3,075,800 MWh) in the test year, the demand component was divided by the total MW and the customer component was allocated based on the number of customers.[10]

The non-fuel based revenue requirement for JPS was based on the assumption that JPS would generate a net 3,792,602 MWh of electricity. It is therefore apparent that a certain amount of anticipated losses are included (passed on to customers) in the computation of the non-fuel based rate. For the energy component of the non-fuel based rate, the inherent loss that is passed on is determined by:

$$\frac{3,792,602 - 3,075,800}{3,792,602} = 18.9\%$$

[10] Actually what is done is that the three components of cost are further divided by customer groups (rate categories) and the non –fuel based rate for each category is determined based on the group's level of kWh consumption, MW demand and number of customers.

It is not readily apparent that there is an implicit incentive for loss reduction built into the computation of the energy component of the non-fuel based tariff. To illustrate this point, the following simplistic computation of the utility's revenue requirement will be used:

$$R^f = \frac{(UC^f \times S^f)}{(1 - l^f)} \qquad (2)$$

where,

R^f	=	Forecasted Revenue Requirement
UC^f	=	Utility's unit cost per kWh generation
S^f	=	Forecast Sales
l^f	=	Forecasted loss

It follows that the non-fuel based rate (NFBR) would be given by:

$$NFBR = \frac{(UC^f)}{(1 - l^f)} \qquad (3)$$

If the actual losses, l^a, are less than the forecasted losses, l^f, with the generation (G) and the unit cost per generation being unchanged (i.e. the utility converts some loss electricity to sales), then it is not difficult to see that the utility would actually get to keep the following amount of extra revenue for which there was no additional cost:

$$(l^f - l^a) \times NFBR \times G$$

Thus, the utility has an incentive for loss reduction. On the other, if the utility's actual losses were greater than the forecasted losses, then the utility would not fully recover the revenues it requires.

The non-fuel based revenue requirement is the revenue excluding fuel costs that JPS needs to provide the supply of electricity to its customers. The assets that were approved by the OUR in JPS' rate base, can, in addition to meet the demand (MW) of the paying customer, provide a specific maximum quantity of MW of lost demand. The difference in the cost of the capacity approved in JPS rate base and the cost of the capacity, which is just needed to meet the customers MW demand, constitute an inherent loss in the demand component of the non-fuel base rate, which is directly passed on to the customers. However, it is the author's belief that this inherent loss is difficult to compute.

The fuel-based rate, as mentioned before, is computed by dividing a fuel cost by the kWh energy sales. The following formula is used to compute the fuel cost that is recovered from the paying customers[11]:

$$CF = CAF \frac{1 - L_s}{1 - L_t} \qquad (4)$$

where,

CF	=	Cost of fuel recovered from paying customers
CAF	=	Actual Cost of Fuel
L_s	=	Actual System Loss
L_t	=	Loss Target

Consider equation (4): if the actual system loss is equal to the loss target, the actual cost of fuel would be fully recovered from the paying customers. However, if the actual system loss is greater than the loss target, the utility only recovers a fraction of the actual fuel cost. The fraction of fuel cost recovered will be dependent on the difference between the system loss and the loss target. On the other hand, if the system losses are less than the loss target then, the cost of fuel recovered from paying customers will be greater than the actual cost of fuel. This is clearly an incentive based mechanism for the utility to reduce system losses.

The loss target set by the OUR in 2004 is 15.8%. This is the same target that has been used since 2001. It is important to note that this loss target is fixed for the five-year

[11] The actual cost includes an adjustment for the heat rate of the system compared to a heat rate target but as this is not the focus, it was ignored from the analysis.

period of the price cap regime, that is, 2004-2009. This target was initially set in 2001 after the OUR examined JPS' system loss record and realized that it was always above 16%. It was thought that a value just below the 16% mark, that is, 15.8%, was a reasonable target to achieve without a significant expenditure.

3.3 Critique of OUR'S Treatment of System Losses

OUR's treatment of system losses in the fuel based rate is a loss target incentive based scheme. Once JPS meets the target it is allowed to keep any efficiency gain above this. However, a penalty is incurred by the utility if it does not meet the target. As was pointed out in [5] the problem with the loss target incentive based approach adopted by OUR in the fuel based rate, is that there was no scientific method in the derivation of the target. Another critique that the author has of the loss target level is that it is fixed over the price cap regime. The author also believes that it is a disadvantage to have only one loss target level for reasons, which will be explained in the next paragraph.

The aim of any loss reduction incentive scheme is to influence the eventual reduction (over time) of both technical and non-technical losses to their optimal economic levels. Typically, it usually requires less expenditure to reduce non-technical losses than is required for technical losses. If only one overall target level is set for system losses then the natural tendency would be for the utility to focus on reducing non-technical losses. Technical losses may not be addressed if the reduction in non-technical losses alone causes the total system losses to meet the loss target level. At some point in time it might not be possible to further reduce the non-technical losses and if the technical losses were not reduced over time, the utility might now be faced with the prospect of needing a much lumped reduction in the technical losses to meet the target level. This would require a large capital expenditure, which the customers would eventually have to pay in the non-fuel base tariff. Thus, it is better to reduce both losses in an incremental manner. In this paper therefore, separate targets levels for the technical and non-technical losses will be used. This approach is used in many other countries.

4. WHAT IS FAIR?

What is fair from an economic point of view is still a topic for much debate by economists. According to Bonbright et al [1], “The most an economist will generally say is that an allocation is “fair” if it is both efficient and equitable”. In the context of bearing the cost associated with system losses from both the utility’s and the customers’ point of view, “fair”, in the author’s opinion, refers to the distribution of costs associated with system losses in a manner which is economically affordable to both parties and which will eventually result in the achievement of the economic optimal value for system losses at some point in time.

According to Hay [4], “for any given system, there is an economic level of technical losses at which benefits to be obtained from additional investments would not be recovered in the benefits of further reduction in losses”. It therefore makes no sense to set the technical loss target below this value because it would be uneconomical for the utility. In theory though, the non-technical losses can be reduced to zero since they are not inevitable and often dramatic improvements can be achieved in this area without significant investment of capital. However, depending on the current level of system losses it might require an extensive amount of investment and time to reduce losses to the minimum economic levels and therefore, the utility must be allowed some time to achieve these values if at all possible.

In the author’s definition of fairness as it relates to bearing the cost of system losses, it was mentioned that any mechanism designed to distribute the cost associated with system losses should aim to minimise the system losses to the economic optimum levels at some point in the future. To achieve this, the author recommends that separate targets levels be set for the technical and non-technical losses and that rather than fixing values for these target levels over the price cap regime period, they should be allowed to decrease over the period within reasonable limits established by the regulatory agency with the intention that at some point in the future they will reach the economic optimum levels. It is suggested that the following formula be used to compute the fuel cost that is recovered from the paying customers:

$$CF = CAF \times \min\left[\frac{1-T_s}{1-T_t}, \frac{1-\frac{N_s}{N_t}T_t}{1-T_t}\right] \qquad (5)$$

where,

CF	=	Cost of fuel recovered from paying customers
CAF	=	Actual Cost of Fuel
T_s	=	Actual Technical Loss
T_t	=	Technical Loss Target
NT_s	=	Actual Non-Technical Loss
NT_t	=	Non-Technical Loss Target
min(a,b)	=	If a≤b then a, otherwise b

Consider equation (5): if both the technical and non-technical losses just meet the set target levels then the fuel cost would be completely recovered from the paying customers. If both the technical and non-technical losses exceed the set target levels, the paying customers would pay a fraction of the actual cost of fuel. This fraction would be dependent on which loss exceeds its target more (relatively speaking). To illustrate, consider the following example:

Assume that the actual cost of fuel is $1billion and that the technical and non-technical loss targets are set at 10% and 5% respectively. Suppose that the actual technical and non-technical losses are 12% and 6% respectively. In this example, each loss exceeds its target by the same relative amount, that is,

$$\frac{12\% - 10\%}{10\%} = \frac{6\% - 5\%}{5\%}$$

Since each loss exceeds its target by the same relative amount, we expect that the fraction of fuel cost which will be recovered from paying customers could be determined by either the technical or non-technical loss as shown below:

$$CF = \$1billion \times \min\left[\frac{1-.12}{1-.1}, \frac{1-\frac{.06}{.05}\times .1}{1-.1}\right] = \$1billion \times \min[0.978,.978]$$

$$CF = \$1billion \times .978$$

Now, consider the case when the relative amount by which the technical loss exceeds it target is greater than the relative amount by which the non-technical loss exceeds its target. In this case, let T_s=13% and N_s=6% and let the targets be the same as in the previous example. The fuel cost that is now recovered by the utility is given by

$$CF = \$1billion \times \min\left[\frac{1-.13}{1-.1}, \frac{1-\frac{.06}{.05}\times .1}{1-.1}\right] = \$1billion \times \min[0.967,.978]$$

$$CF = \$1billion \times .967$$

Here, it is the technical loss that determines the fraction of the fuel cost recovered from customers since the relative amount by which the technical loss exceeds its target is greater than for the non-technical loss. Of course, the formula would also work if the converse were true.

If both losses are less than the set targets, then the cost of fuel recovered from paying customers will be greater than the actual cost of fuel. However, the cost recovered will be dependent on the loss that exceeds its target the least (relatively speaking). When only one loss exceeds its target then the utility will be penalized no matter how well it does on the other objective. It should therefore be obvious that this scheme encourages the utility to reduce both technical and non-technical losses at the same time and that a reward is only given when both losses are less than the loss target levels. The utility might argue that it is unfair to penalize it if it is able to do very well with one loss but was unable to reduce the other loss below the target level especially since it is the reduction of total losses that affect costs and revenues. The utility will argue therefore that it should be able to decide which loss is more cost effective to reduce. However, the author has already pointed out in Section 3 of this paper, a good reason for reducing both losses together over time.

It can actually be shown through computation that when both losses are greater than the target levels, the penalty placed on the utility will be less than if the total system loss was used in the computation (that is, if equation (4) is used). On the flip side though, when the losses are below the target levels, the utility will get less rewards if the computation is done using equation (5). There may be an advantage to be gained here “as the incentive should not be too strong or too weak” [8].

The incentive scheme for loss reduction described in equation (5) gives equal weighting to exceeding the technical and non-technical loss targets but, considering that less capital efforts are normally required to reduce non-technical losses as opposed to technical losses, the above formula could be modified to apply different weightings to the non-technical and technical losses. This means that a greater penalty could be applied to exceeding the non-technical loss target than the technical loss target. One drawback of using unequal weightings however is that the regulator would have to develop an oversight of the utility’s determination of both the technical and non-technical losses.

The author would like to reiterate that to be fair to the utility; it is recommended that the loss target levels N_t and T_t, should not be fixed to the desired optimal economic loss levels over the price cap regime period, as was previously discussed in this Section because the utility may not be able to reduce its losses to these levels within a short time and hence will be unduly penalised. The following table gives an example of how the loss target levels could be set over the price cap regime period.

Year	Technical Loss Target Level T_t (%)	Non-Technical Loss Target Level N_t (%)
2004	9.5	7.0
2005	9.3	6.5
2006	9.1	6.0
2007	8.8	5.6
2008	8.6	5.3
2009	8.5	5.0

Table 2: Example of a recommended target levels over a price cap regime period

The values given in Table 2 are values that have been concocted by the author. They are not based on any studies or detailed analysis. Meaningful values for the target levels over the price cap regime period can be obtained only after carefully analysing historical losses trend, considering past loss reduction initiatives and results, and an evaluation of the loss levels that would reflect the utility's proper operating practices.

Considering the current economic climate in Jamaica where the high price of fuel is having an adverse effect on the price of electricity and the economy as a whole, the author is proposing that the regulatory asset method described in [5] could have been applied to the Jamaican context. Thus, some of cost associated with the targeted losses could be postponed and recovered in the future.

The government has plans of diversifying the fuel mix used in the country and based on its memorandum of understanding (MOU) with the Trinidad and Tobago government, it is anticipated that liquefied natural gas (LNG) will be available for electricity generation in the medium term. Under the MOU, the cost of LNG supplied to Jamaica from Trinidad will be much less than world market prices. This will have the effect of significantly reducing the fuel based rate in the tariff. It is therefore prudent to defer some of the cost associated with target losses being incurred now by the customers, to the point when the fuel based tariff rate is expected to decrease significantly (as a result of LNG use) and the overall cost to the customers would not be a burden. But the question could be asked: Is this affordable to the utility? If the return on the investment on the regulatory asset (deferred cost) is set to the utility's weighted average cost of capital then the utility would be indifferent to the deferment. In effect it is equivalent to the utility taking out a loan for the customers and allowing them to pay it over time.

In most of this section, the emphasis have been placed on loss reduction incentives in the fuel based tariff, however, some recommendations could also be given for incorporating some amount of fairness in the non-fuel based tariff. As was previously discussed, the utility stands to make a gain if actual system losses are less than the forecasted losses used in the calculation of the revenue requirement. The author recommends that the regulator should possibly examine sharing the benefits with the customers, especially since the revenue requirement was determined at a time when the system losses was relatively high and hence its was designed for a high anticipated loss. Consequently if the system loss is reduced to reasonable levels, the Utility stands to gain big. On the same note, because the revenue requirement was designed for a high anticipated loss, the utility will not be penalised much for high losses (which may be only slightly greater than the anticipated loss). The regulatory agency should perhaps consider the introduction of a separate item relating to measure losses into the price control mechanism whereby losses are directly calculated and incorporated into the model.

5. THE ROLE OF GOVERNMENT IN THE SCHEME OF THINGS

Since commercial losses originate for various reasons, a single approach for mitigating may not suffice [10]. Certainly utilities have some control over the magnitude of commercial losses; but even with their best efforts, some commercial losses would still continue. Consequently, an effective policy of reducing losses may require regulatory action directed at both utilities and consumers.

The government also has an important role to play in facilitating non-technical loss reduction measures proposed by the utility. To deter pilferage of electricity and/or non-payment of bills, the government has to enact laws and ensure that these laws are enforceable. It would be unfair for the utility to be penalised for not meeting the non-technical loss target level if its loss reduction measures are being hampered by inadequacy in legislation. It is also often the case that political barriers exist to shutting off service to non-paying consumers. The regulator should therefore assess the societal constraints before setting the non-technical loss target.

6. CONCLUSION

The aim of this paper was to examine the regulatory treatment of system losses in Jamaica and to propose mechanisms which in the author's opinion would be "fairer" to both the utility and the customers.

The paper first discussed the issue of system losses and its implications for both the customers and the utility. Existing regulatory structures proposed in the literature were then highlighted. And it was then shown how these structures are applied in different countries around the world.

Although there are only a few general approaches to regulatory treatment of system losses, losses, especially commercial losses are complex and each country should have a solution tailored to its own unique situation. The countries examined had varying approaches for dealing with losses. The approaches adopted were based on the usual levels of system losses, the nature of the losses and the economic level of the country. For example, the United State government is able to subsidise a portion of the system losses.

New mechanisms for regulatory treatment of system losses in Jamaica were proposed. One approach was to separate the non-technical and the technical losses and to set different target levels for each. A formula using these two loss targets was proposed for calculating the cost of fuel to use in the fuel-base tariff. It was also suggested that loss target levels should not be constant over the price cap regime period, but rather, should start off at a reasonable level and then gradually be reduced over the period. The author also recommends that consideration be given for the sharing of the benefits that the utility will attain by achieving lower losses than that which was designed in the non-fuel based rate. It was also recommended that the regulatory agency should perhaps consider the introduction of a separate item relating to measure losses into the price (price cap) control mechanism whereby losses are directly calculated and incorporated into the model. Finally, to take into consideration Jamaica's current economic climate, current high cost of fuel and the fact that the fuel cost is expected to decrease over the medium term, a regulatory asset method (deferment of some of the cost associated with the target losses) could have been applied.

Although the proposals in this paper are preliminary, they represent a useful starting point for re-examining the current regulatory arrangement in Jamaica. The literature has also shown that deregulation and privatisation of the electric utility is a useful way of facilitating the reduction of system losses[12] and the OUR should never rule out this consideration.

[12] System Losses have shrunk in several countries in South America where deregulation has taken place: For example, losses in Chile, energy theft included, were halved in seven years and in Argentina, in just three years [9].

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