THE PORTUGUESE TARIFFS FOR USE OF TRANSMISSION NETWORK – STUDY ON THE IMPLEMENTATION OF A MARGINAL BASED TERM

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Abstract – In 1999 and 2000 the Power Systems Unit of INESC – Porto, Portugal, conducted a consultancy study under a contract with the ERSE – the Portuguese Electricity Regulatory Board – to evaluate the interest of considering alternative cost allocation methods apart from the currently used Postage Stamp to set Tariffs for the Use of Transmission Network. This paper summarizes the main results that where obtained, regarding the eventual integration of a short term marginal based component in those tariffs. It should be clarified that it was not the purpose of this study to question the regulated approved remuneration of the transmission company, but only to consider the potential interest of using alternative cost allocation methods, regarding the current Postage Stamp tariffs.

1. INTRODUCTION

In the last 30 years the Portuguese electricity sector has been going through a set of changes that, with the recent moves, will lead to a common Iberian market between Portugal and Spain, and will finally integrate the EU larger sector. The Portuguese electricity industry was nationalized in 1975 as an answer to social concerns and to the need to finish the electrification of the whole country. This move lead to the creation of EDP, a state owned company in the first place, that afterwards passed to EDP SA, a society of public participations. In 1988 it was passed new legislation aiming at inducing new investments to use endogenous resources – cogeneration, small hydros and wind parks. The energy from these non dispatchable sources had, by law, to be accepted in the public system and was paid basically at avoided costs. This turned these investments very attractive leading to the present situation in which about 15% - about 1500 MW - of the total installed power comes from these Special Regime Generation, with the particular interest of being in their large majority connected to distribution networks.

In 1995, anticipating in some years the approval and entering in force of the EU 96/92 Directive on the Internal Electricity Market, the Portuguese Government approved a vertical and horizontal change in EDP SA. By then, it was created an holding company under which there were a set of child companies. These child companies were devoted to large hydro and thermal generation, four distribution integrated companies (in the sense they included network and retailing functions), a transmission (400kV/220kV/150kV) company as well as a number of services and consulting companies. The legislation of 1995 also created a new legal framework in the sector by adopting, for the first time in the sector in Portugal, the principles of independent regulation. According to these ideas it was created ERSE – Entidade Reguladora do Sector Eléctrico – having a large number of regulatory, administrative and sanctionatory functions.

The basic idea behind the vertical and horizontal restructuration of 1995 was to start privatizating the child companies that emerged from the EDP SA reorganization. That process started in 1997 but not on the child companies. In fact, EDP SA holding started to be privatized thus progressively leading to a large almost monopolist private group. Nowadays, EDP SA is a majority private group from which it was split the Transmission Company – REN SA – given the need to ensure the independence of the transmission provider. REN SA is assigned functions in terms of transmission provider and in terms of system operator, thus becoming a key entity in ensuring the safe operation and expansion of the transmission sector, acting as what is known as Transmission System Operator, TSO.

The legislation of 1995 organized the sector in terms of a public service driven system a market driven system. In the public service system Regulated Generators – owned by EDP SA and other private investors – and Regulated Distributors are tied by long term contracts with the TSO. In the market driven area generators, eligible consumers and distributors can establish bilateral contracts or present their offers to a pool system, still not implemented at the moment. It was expected by public authorities that, through time, the public service sector would progressively reduce its share as long term contracts would exhaust their life time or as new built generation plants would join the market driven sector. For several reasons, mainly related to the much less risky environment in the public driven sector, that evolution did not occur and the market driven sector did not manage to enlarge its importance. Recent political developments (November 2001) lead to an agreement between Portuguese and Spanish authorities to create a common Iberian Pool system, most likely based on the well established Spanish Pool. This new Iberian Pool will be in place in the 1st of January of 2003, meaning that there is now one year of hard work and negotiations that will hopefully lead to an harmonization of legal and regulatory provisions in the two countries. If this Iberian Pool comes to life, it will be a major development for Portugal and Spain, not only by itself, but also because it will in fact correspond to the second major experience of integration of national electric systems, following the establishment of the NordPool between Norway and Sweden in 1996 and its posterior enlargement to Finland and Denmark.

This organizational evolution was accompanied by a major change regarding regulatory processes and tariff schemes. Following the legislation of 1995, the Portuguese Electricity Regulatory Board, ERSE, passed in 1998 a number of new regulations aiming at shaping the new technical and commercial relations among entities in the sector. Among them, it was passed a new Tariff Regulatory Scheme directed both to the transmission and to the distribution sectors. Regarding the transmission sector, and among other provisions, the Tariff Regulation adopted a Cost of Service/Rate of Return, CoS/RoR, remunerated regulation from which comes by November each year the regulated remuneration approved for the following year. That remuneration is recovered by two Postage Stamp based tariffs that enable agents to use the networks and to establish contracts away from the referred long term scheme, namely with Spanish providers. The referred transmission tariffs are:

- a Global Use of System Tariff designed to recover global costs of system operation, ancillary services and to support the budget of the Regulatory Board. It has a price of active energy in $/kWh and it is paid by all agents in the system;
- a Tariff for Use of the Transmission Network established considering:
  - a discrimination in terms of the voltage level to which each entity is connected to, leading to Extra High Voltage and High Voltage tariffs;
  - prices for power (PTE/kW.month) and for reactive received or supplied energy (PTE/kVAr.h). The price for power is applied to the power obtained using average values for peak and full hours in each month. The price for supplied reactive energy is applied to the inductive energy that exceeds 40% of active energy in off valley hours. The price for received reactive energy is applied to all reactive energy received in valley hours.

The first regulatory period started in 1999 and is finishing by the end of 2001. By 2000 the revision of different regulations started to be discussed, namely the Tariff Regulation. In this scope, the Power Systems Unit of INESC Porto – a non profitable private research institute linked to several Portuguese Universities – conducted a study under a contract established with ERSE in order, among other issues, to evaluate the interest of including a short term marginal component in the Tariff for Use of Transmission Network. This paper reports the major results included in the final report in terms of eventually considering an alternative marginal term in the Tariffs for Use of Transmission Networks. The complete report [1] is available in ERSE WEB page under the location http://www.ERSE.pt.

A final word to stress a basic assumption under which all the simulations were conducted. It was not the objective of this work to propose alternative approaches to the currently CoS/RoR regulation in force for the transmission company. It was not also our objective to question the regulated remuneration that has been approved yearly by ERSE and that is recovered by the transmission provider. Our only objective was to evaluate the interest of adopting alternative cost allocation methods – apart from the currently used Postage Stamp approach – to recover the same amount of yearly regulated remuneration.

2. USE OF NETWORK COST ALLOCATION METHODS

2.1. Costs and Regulation

The implementation of market mechanisms in the electricity sector had an enormous effect in adopting more transparent procedures, for instance in terms of cost identification and in reducing cross subsidies. Although a legal separation of commercialization distribution, transmission and generation activities is not always required, at least an account separation is needed in order to build tariff schemes, namely for network activities, that allow companies to recover their costs. Among the available regulatory frameworks in use in the network activities one can refer:

- CoS/RoR – Cost of Service/ Rate of Return – it remunerates approved costs of the regulated company plus an amount established according to a rate of return on investments and assets. This is the traditional regulatory approach that, in any case, is still in use in the transmission sector in several countries given that these companies are usually very efficient and the share of their costs in the price of the final product is small;
- Incentives Regulation – it can be established according to Benchmarking, Price Caps or Revenue Caps. These approaches recognize that an activity is less efficient than what it should be, so that it is important to transmit signals to induce the adoption of more efficient behaviors. Due to the reduced amount of investments directed to distribution is the past, to the lower levels of automation, to the more

degraded quality of service and to the larger share of distribution costs in the price of the final product, distribution companies are usually regulated according to approaches of this type.

Once the regulatory framework is selected and the respective yearly costs are approved, a second moment of the regulatory process is started with tariff setting. There are a large number of methods to allocate costs among network users gathered in three main groups: Embedded, Incremental and Marginal methods.

2.2. Embedded Cost Average Approaches

Embedded methods are usually easy to implement once their basic assumptions and simplifications are accepted [2, 3]. Some of these methods don't even require running any kind of technical simulation study (power flow, for instance) and are known as Rolled In methods. Examples of methods of this class are the Postage Stamp, the Contract Path or the Mean Participation Factors. Another subclass of Embedded methods has a larger technical accent in requiring running power flow studies. MW.mile, Modulus or Use, Zero Counter Flow and Dominant Flow are examples of methods of this subclass. In any case, these methods correspond to average cost allocation approaches and, in that sense, they inherently display some level of cross subsidy procedure.

2.3. Incremental Methods

Incremental approaches [4] aim at comparing the cost functions of two problems. One of them corresponds to a base reference situation, while in the second one it is included the transaction to be evaluated. The surplus of cost corresponds to the amount to allocate to the entities involved in this transaction. Examples of this type of methods are the Areas of Influence and Benefit Factors. These are transaction based methods conceived when the number of wheeling transactions was small. When the number of transactions is large or when the market is organized in terms of a pool, these methods require a large amount of simulations and they often lead to less transparent results.

2.4. Marginal Methods

Marginal approaches are well established for a long time in several power system domains as in generation dispatch [5]. However, it was more recently, that marginal procedures started to be used to set Tariffs for Use of Networks and to frame the partial recovery of the regulated remuneration of network providers [6]. The interest in using marginal approaches comes from the fact that marginal prices are inherently able to transmit economic signals to the players in terms of inducing more efficient behaviors. These signals are either short or long term, depending on the time horizon used to frame their calculation, and display a geographic dispersion. This dispersion is related to some basic issues that are often forgotten when discussing electricity markets. These markets are not traditional commodity ones because:

- electricity is not a product or service that can be stored for a long period and be marketed in a very short time whenever required. Apart from hydro resources, thermal plants have implicit technical constraints that explain this feature;
- secondly, pure market driven decisions have very frequently to be adapted due to the presence of a transmission network that operates according to Kirchoff Laws. In this sense, transmission congestion and security issues are of utmost importance in power systems.

In this sense, electricity markets should be more properly called **Electricity Technically Constrained Markets** to stress the impossibility of eliminating the influence of technical constraints. The presence of a network has an effect on prices due to congestion and to active losses, in the sense that given the different location of generation facilities and loads, the marginal prices tend to be higher in load predominant areas and to be more reduced in generation areas. This fact leads to the concept of Nodal Marginal Price, ρ_k, that can be defined as the impact on the cost function, Z, of the optimization problem of varying the load, P_{lk}, at a given node k of the system (1).

$$\rho_k = \frac{\partial Z}{\partial P_{lk}} \tag{1}$$

Nodal Marginal Prices can be computed in terms of a long term simulation that aims at minimizing both long term investment costs as well as the expected value of operation costs. Long Term Marginal Prices, LTMP, are difficult to be computed because they involve solving a long term expansion planning problem dealing with discrete decisions and uncertainties along the period. Apart from LTMP, Short Term Marginal Prices, STMP, only reflect short term operational costs. This turns their calculation much easier, basically in terms of a subproduct of a minimization problem. This problem can correspond to a non-linear formulation if eventually one aims at calculating both active and reactive marginal energy prices, or can more frequently correspond to an enhanced linear formulation solved by means of efficient Simplex based commercial codes.

2.5. Criteria to Evaluate the Goodness of Cost Allocation Methods

The referred cost allocation methods display very different characteristics and should therefore be traced for a number of criteria, enabling a more sounded decision if one of them has to be selected. The following criteria should be considered in this evaluation:

- Technical robustness – in the sense that tariff decisions deal with the flow of money so that accountability is a key issue namely by giving a larger technical accent to several decisions;

- Economic efficiency – in terms of the quality of economic signals sent to the participants to induce improvements in their behavior;
- Fairness – to allocate costs of network companies to the users responsible for them avoiding cross subsidies, as much as possible;
- Applicability to pool anonymous markets – given that pure transaction based methods require knowing the entities involved in a transaction. This information is not available in a pool market;
- Easiness of application – this will increase the confidence of participants and will contribute to improve the transparency;
- Potential tariff stability – the method should not lead to tariffs too much dependent on particular operation conditions. This would create an extra unnecessary source of uncertainty.

Table I presents a classification of several cost allocation methods according to these criteria.

Table I – Classification of the goodness of cost allocation methods according to some criteria.

		Technical Robustness	Economic Efficiency	Fairness	Applicability to Anonymous Markets	Easiness	Tariff Stability
Rolled in Embedded Methods	Postage Stamp	no	no	min	yes	max	yes
	Contract Path	no	no	min	no	max	yes
	Mean Participation Fact.	no	no	min	no	max	yes
Power Flow Based Embedded Methods	MW.Mile – PF studies	yes	med	med	yes	med	yes
	Modulus or Use	yes	med	med	yes	med	yes
	Zero Counterflow	yes	med	med	yes	med	no
	Dominant Flow	yes	med	med	yes	med	no
	GAPP	yes	med	med	no	min	yes
Incremental Approaches	Areas of Influence	yes	max	med	difficult	min	no
	Benefit Factors	yes	max	med	difficult	min	no
Marginal Approaches	Short Term - STMP	yes	max	max	yes	med	no
	Long Term - LTMP	yes	max	max	yes	min	yes
	ICRP (approx. LTMP)	med	med	max	yes	med	no

3. THE COST ALLOCATION STUDY

3.1. Evaluation of Short Term Marginal Prices

In this work the computation of STMP was accomplished by solving the optimization problem (2) to (7). This problem aims at minimizing generation costs (2) subjected to a global balance equation (3) as well as to generator constraints (4) and (5) and to branch capacity ranges (6) and (7).

$$\min\ Z = \sum c_k . Pg_k + G.\sum PNS_k \tag{2}$$

$$\sum Pg_k + \sum PNS_k = \sum Pl_k \tag{3}$$

$$Pg_k^{min} \le Pg_k \le Pg_k^{max} \tag{4}$$

$$PNS_k \le Pl_k \tag{5}$$

$$\sum a_{bk} .(Pg_k + PNS_k - Pl_k) \le P_b^{max} \tag{6}$$

$$\sum a_{bk} .(Pg_k + PNS_k - Pl_k) \ge P_b^{min} \tag{7}$$

In this model Pg_k is the generation in node k and c_k is the corresponding variable cost, PNS_k represents the output of the fictitious generator connected to bus k to simulate Power Not Supplied, G is the penalty specified for PNS, Pg_k^{min} and Pg_k^{max} are the generation ranges, P_b^{min} and P_b^{max} are the transmission limits of branch b and a_{bk} is the DC based sensitivity coefficient translating the impact in the branch flow in branch k from changing the injection in node k of one unit.

This model was enhanced by considering an iterative process to include an estimate of transmission losses. This step was important since transmission losses contribute to increase the geographic discrimination of nodal marginal prices thus leading to an increase of the Marginal Based Remuneration. Following the ideas in [6] losses in branch ij were approximated by (8) in which g_{ij} is the branch conductance and θ_{ij} is the phase difference along branch ij.

$$Loss_{ij} \approx 2.g_{ij}.(1-\cos\theta_{ij}) \tag{8}$$

The estimate of transmission losses was included according to the following algorithm:

i) Solve problem (2) to (7) and set iteration counter itr at 1;
ii) Built the nodal injection vector and compute voltage phases using the inverse of the DC model bus admittance matrix;
iii) Estimate branch losses using (8) and add half of the losses in branch ij to each of the loads in its extreme buses;
iv) Solve problem (2) to (7) considering the new load vector and increase itr by 1;
v) Built the nodal injection vector and compute voltage phases using the inverse of the DC model bus admittance matrix;
vi) Check convergence by comparing voltage phases between two consecutive iterations. If convergence was not yet reached return to iii).

The expression for the Short Term Marginal Price in node k, for a given set of operational conditions is model dependent and, for the above formulation, is given by (9).

$$\rho_{ik} = \gamma_i + \gamma_i.\frac{\partial Loss}{\partial P_{lik}} + \sum_j \mu_{ij}.\frac{\partial P_{mn}}{\partial P_{lik}} + \sigma_{ik} \qquad (9)$$

In expression, ρ_{ik} represents the nodal marginal price at node k for a given load scenario i, γ_i is the Lagrange multiplier of the generation/load balance equation (3), P_{Lik} is the active load at node k in scenario i, P_{mn} is the active flow from node m to node n, μ_{ij} is the dual variable of an active branch limit constraint in scenario i, σ_{ik} is the dual variable of the Power Not Supplied limit constraint in node k in scenario i and Loss represents the active losses at all system branches at scenario i. This corresponds to a Short Term Marginal Price [5], [6] measuring the impact in the cost function of a change of 1 unit in the load at node k at scenario i.

Accepting that loads pay the price at the node they are connected to and that generators are remunerated at the price at the node they are connected to, we can estimate the Marginal Based Remuneration, MBR, assigned to the transmission provider using (10). In this expression, NSC is the number of scenarios, NNodes is the number of nodes of the network, P_{Lik} and P_{Gik} are the load and generation at node k in scenario i and d_i is the duration of scenario i.

$$MBR = \sum_{i=1}^{NSC} \sum_{k=1}^{NNodes} \rho_{ik}.(P_{lik} - P_{Gik}).d_i \qquad (10)$$

3.2. Assumptions Under Short Term Marginal Methods

The simulations considered some basic assumptions that will be detailed in the next paragraphs:

- in the first place, the Portuguese generation system is a mixed hydro-thermal one. This indicates that its operation and simulation requires some water management module or the knowledge about the Value of Using Water. Neither that module nor the Value of Using Water in several reservoirs were available. To overcome this problem, and in order to obtain generation results from the simulation software in each considered scenario compatible to the data in those scenarios, we substituted constraints (4) for hydro stations in model (2) to (7) by constraints as (11). In this constraints Pg_k is the generation in generator k, $Pg_{k,sc}$ is the generation value included in the data for scenario sc in that station and Δ_g is a small variation allowed to affect the final value of Pg_k;

$$Pg_{k,sc} - \Delta_g \le Pg_k \le Pg_{k,sc} + \Delta_g \qquad (11)$$

- it was considered that all system components were ideal in the sense there would be no outages through an year of simulations. The incorporation of reliability issues can be done considering a Monte Carlo Chronological module that would sample outages according to failure rates and would simulate the reparation of components considering repair rates.

4. CASE STUDY

4.1. The Portuguese Generation/Transmission System

In the year 2000 the Portuguese generation system had an installed capacity of about 10400 MW for a peak capacity of 6557 MW and a supplied energy of 35109 GW.h. The Portuguese Public Driven Generation system included about 40 stations of different technologies:

- hydro plants – 3903 MW;
- thermal coal fire plants – 1776 MW;
- thermal fuel plants/thermal gas – 1852 MW;
- thermal fuel plants/thermal natural gas – 236 MW;
- thermal natural gas – 990 MW.

Apart from these, there were about 272 MW of market driven generators and about 1404 MW of dispersed generation (small hydros, wind parks and cogeneration) mainly connected to distribution networks. The plants are located in a fairly irregular way along the territory. Hydro plants are located predominantly in the north part while thermal ones are located all, except one, in the central and southern areas. This pattern, together with a 400 kV interconnection with Spain in the north and another in the south determines very different operation conditions in wet winters and dry summers. In wet winters large flows come from the north to the south and in typical dry summers this situation is reverted.

4.2. Results Obtained For STMP

We defined a number of generation/load scenarios – some of them made publicly available in [7] and related to peak, full and valley hours, to wet and dry periods and to summer, winter and spring/autumn conditions. These scenarios are grouped in three sets:

- Peak scenarios under Dry or Wet conditions in Winter, Spring/Autumn or Summer: PWW, PDW, PWSA, PDSA and PDS;
- Full hour scenarios under Dry or Wet conditions in Winter, Spring/Autumn or Summer: FWW, FDW, FWSA, FDSA and FDS;
- Valley hour scenarios under Dry or Wet conditions in Winter, Spring/Autumn or Summer: VWW, VDW, VWSA, VDSA and VDS.

Once these scenarios were defined, we computed nodal marginal prices in the nodes of the 400kV/220kV/150kV network system for each scenario according to the indications in Section 3. In Figure 1 we display the simplified transmission network with the nodal prices obtained for some nodes in scenario PDS, Peak Dry Summer. One can notice that prices are higher in some nodes in the eastern central area mainly due to congestion problems. The southern area corresponds to a number of 150 kV lines poorly meshed. In terms of marginal prices, this leads to a steady increase of nodal prices as one gets away of generation areas and goes deeper into load areas.

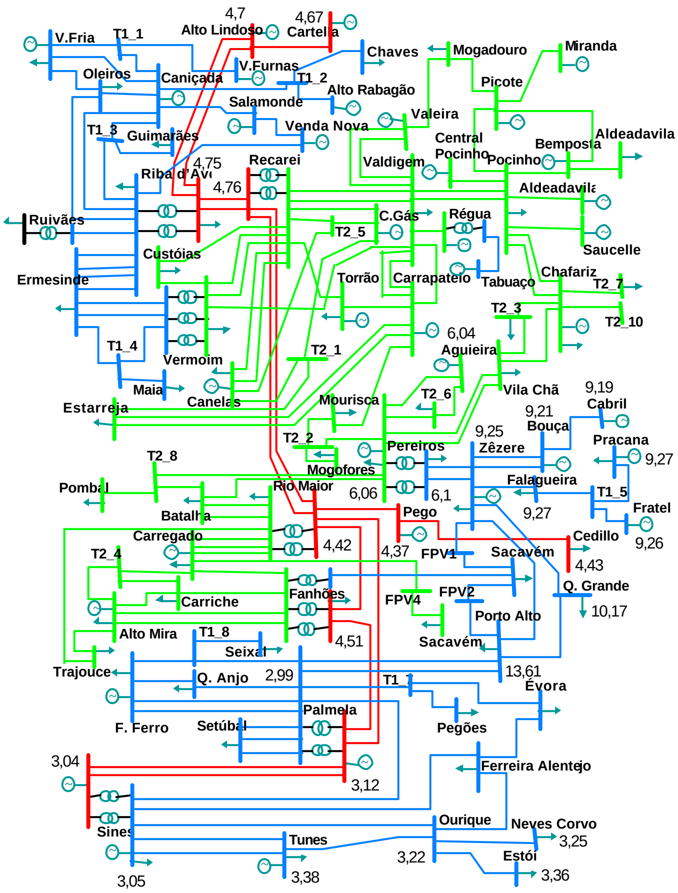

Figure 1 – Portuguese 400/220/150kV system with prices in some nodes for the PDS scenario.

Table II includes the results obtained for the marginal based remuneration of the 15 scenarios. The second column indicates the hourly remuneration admitting that loads pay and generators are paid the price in the node they are connected to. The third column indicates the duration of each scenario according to regulatory provisions for the peak, full and valley hours. Column four gives the remuneration of each scenario as the product of the two previous figures.

Once this study was completed, it was possible to conclude that, for the year of 1998, the Marginal Based Remuneration would only cover about 9,15% of the regulated remuneration of the transmission company. From Table II one can also notice that scenario PDS – Peak Dry Summer, is responsible for almost one third of that yearly amount. These figures indicate there would be a large Revenue Reconciliation Problem since there should be tariff terms set to recover as much as 91% of the regulated remuneration. This definitely comes from the fact that short term prices do not reflect investment costs, and for that particular year the level of congestions was reduced.

Table II – Per hour remuneration, duration and remuneration of each of the 15 considered scenario.

Scenario	Per hour Remuneration (PTE/h)	Duration (h)	Remuneration of the Scenario (10^6 PTE)
PWW	556619.74	162.95	90.70
PDW	381666.29	162.95	62.19
PWSA	198446.84	260.71	51.74
PDSA	241646.86	260.71	63.00
PDS	3632738.54	195.54	710.35
FWW	285234.45	436.70	124.56
FDW	372445.90	436.70	162.65
FWSA	177936.84	938.57	167.01
FDSA	194710.82	938.57	182.75
FDS	313558.27	1003.75	314.73
VWW	159419.65	495.36	78.97
VDW	190417.49	495.36	94.33
VWSA	88239.08	990.71	87.42
VDSA	117588.40	990.71	116.50
VDS	103782.37	990.71	102.82
		TOTAL	2409.70

5. CONCLUSIONS

In this paper we described the main results obtained in the scope of a consultancy study developed by the Power Systems Unit of INESC Porto to the Portuguese Regulatory Board in order to evaluate the interest of application of alternative methods to allocate costs of the transmission provider to network users. In particular, it was concluded that, even very appealing from a purely theoretical point of view, short term marginal prices would only recover 9,15% of the 1998 regulated remuneration. This figure can be considered conservative since it will certainly increase if reliability issues were considered. It should also be stressed that new simulations must be done in order to check if the network operation characteristics for 1998 – low level of congestion – still hold in more recent years. As whole, and if the marginal based remuneration does not increase in a very abrupt way, it is our opinion that it is pointless to include short term marginal tariffs in the Portuguese Tariffs for Use of Transmission Network.

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