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USE OF POWER FLOW BASED EMBEDDED METHODS TO SET TARIFFS FOR USE OF NETWORKS – A CASE STUDY USING THE PORTUGUESE TRANSMISSION COMPANY

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Abstract – In the scope of a consultancy study conducted by the Power Systems Unit of INESC Porto, the yearly regulated remuneration of the Portuguese transmission provider was allocated to the network users considering an approach based on power-flow embedded methods. The tested cost allocation methods were the MW.mile, the Modulus and the Zero Counterflow. The application of that approach lead to geographically discriminated Tariffs for Use of Transmission Networks. This study must be considered as a contribution to the revision process of the current regulations when the first regulatory period is about to end. It should be emphasized that it was not the purpose of this study to question the current Cost of Service/Rate of Return strategy in force in the Portuguese transmission sector and to calculate the adequate yearly remuneration of the transmission provider. The only objective of this study was to simulate the application of alternative cost allocation approaches, given that the whole amount to allocate is fixed by current rules. In this way, we think it is possible to contribute to a more technically sounded discussion about the advantages and drawbacks of several approaches.

I. INTRODUCTION

Following the legislation passed in 1995 imposing a new organizational structure to the electricity sector, a set of new regulations came into force from 1998 onwards. Among them we can refer the Tariff Regulation, the Regulation of Transmission Networks, the Regulation of Distribution Networks and, more recently, the Quality of Service Regulation. The legislation of 1995 organized the National Electricity System – SEN – into two main sub-sectors called Public Service Electric System – SEP – and Independent Electric System – SEI. The SEP integrates entities having generation long term tying licenses – Tied Generators, distribution tying licenses – Tied Distributors and Tied Clients. The SEP is operated and planned on a public service basis directed to supply all clients on a universal and uniform basis. In the SEP the security of supply is assured by long term planning actions, by long term generation contracts – Power Purchase Agreements – and by the centralized operation performed by the entity having the concession of the National Transmission Network.

The Independent Electric System – SEI – integrates two subsystems corresponding to the Non-Tied Electric System – SENV - and the generation entities under a special regime – PRE – basically corresponding to cogeneration, small hydros (till 10 MVA) and renewables. The SENV integrates Non-Tied Generators, Distributors and Clients. The operation of the SENV is based on contracts freely established between entities in this subsystem and on the use of the networks owned by entities integrated in SEP through the payment of Tariffs for Use of Networks. Regarding the generation under special regime – PRE – it should be referred that specific legislation obliges the SEP entities – either Tied Distributors or the entity having the concession of the National Transmission Network – to buy all their generation. The extra costs due to these acquisitions are incorporated in Tariffs paid by all clients of the SEN, either integrated in the SEP or in the SENV.

In order to turn the operation of this system transparent and to avoid cross subsidies, the legislation imposed a contabilistic separation of activities in the previously vertically integrated company – EDP SA. Back in 1994, EDP was split into a generation company devoted to large hydro and thermal plants, a transmission company having the concession of the National Transmission Network, four tied distribution companies and a number of smaller companies devoted to services. The holding controlling all these companies started to be privatized and already in 2000 within the fourth privatization step the majority of the shares became private. More recently there were new changes representing both a step forward and a step backward in the move to a more decentralized, transparent and competitive structure. In fact, the four distribution companies were remerged into a single one meaning a move away the required horizontal restructuration in order to increase the number of players in the system. On the other side, REN – the company having the concession of the National Transmission Network – was legally separated from EDP holding thus preventing the transmission network from being controlled by a majority private company. REN remains today as majority public company playing a key role in the organization of the sector both in terms of physically connecting the different players and also being in charge of managing a still incipient poll system.

This change in the structure of the system was accompanied by the implementation of more transparent regulatory practices adapted to the situation of each sector of activity. Regarding the transmission activity it was adopted a regulation by Cost of Service/Rate of Return recognizing that REN already obtains good performances, that the levels of quality of service are good, that there is no risk of over or under investment and that the share of transmission costs in the price of the final product is reduced. Transmission costs fixed along the regulatory period are basically recovered by Tariffs for Use of Transmission Networks. These tariffs are set according to a Postage Stamp approach and have a voltage discrimination in terms of a Tariff for the Use of Extra High Voltage Networks and a Tariff for the Use of High Voltage Networks. These Tariffs integrate a price for supplied power in PTE/kW.month and two prices for reactive energy in PTE/kvar.h depending on the reactive supplied or received energy.

Regarding the distribution sector, the economic and technical performance is worse when compared with the transmission sector, the level of investment is larger and the share of distribution costs in the price of the final product is much larger than with transmission. Recent figures indicate values between 40 and 50% for distribution costs in the structure of the energy

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price and a similar figure regarding the share of investments in the distribution sector. Accordingly, a Revenue Cap Incentive Regulation is in force in the distribution sector.

The first regulatory period started in 1999 and will end in 2001. It corresponds to a crucial period of adaptation and monitorization of the performance of the companies on which it was important to have simple tariff mechanisms and regulations and during which more involving studies aiming at refining the current tariff mechanisms can be performed. In this scope, the Power Systems Unit of INESC Porto developed a consultancy study for the Portuguese Electricity Regulatory Agency – ERSE – aiming at studying the application of cost allocation approaches, namely in the transmission sector, alternative to the currently used Postage Stamp. It is important to refer that it was not the purpose of this consultancy work to question neither the use of the Cost of Service/Rate of Return regulation to the transmission sector nor the amount of money that has been fixed using this approach as the regulated remuneration of the transmission provider. Our only objective was, in fact, to study the application of alternative methods in order to allocate the referred regulated remuneration to the network users.

In the referred consultancy study we simulated the application of both power-flow embedded methods and short term marginal prices to recover, at least partially, the yearly regulated remuneration of the transmission company. Regarding the application of short term marginal prices, our main goal was to estimate the percentage of the yearly regulated remuneration that could be obtained using nodal prices. Our main conclusion in that part of the work was that nodal prices would lead to a reduced amount of the remuneration – around 10% - thus requiring the presence of other largely dominant tariff terms. The methodology used to estimate the marginal remuneration is the object of another paper presented in this Conference.

In this paper and given its importance, we will focus on the methodology and results obtained by the application of power-flow embedded methods either to obtain the whole regulated remuneration or to recover 90% of that remuneration in case a marginal based tariff term would eventually be approved. Given this reasoning, Section 2 gives detailed information about the application of three power-flow based approaches to allocate costs. In Section 3 we present results that were obtained on the Portuguese transmission grid. Section 4 discusses those results in terms of their nature and advantages/disadvantages and Section 5 presents some conclusions, namely in view of the already referred legislation passed 1995.

II. DESCRIPTION OF THE ADOPTED METHODOLOGY

The developed methodology is based on three alternative embedded cost allocation methods and considers two main steps. In the first step, it is evaluated the cost of use of the network to assign to each load. As a result of this step, we calculate coefficients reflecting the cost of the network equipments to assign to a load j given the use of those equipments by that load. In a second step, these coefficients are used to distribute the yearly regulated remuneration of the network company proportionally to the use of the network by each load when compared to the global use by all loads. It is important to mention, that it is ensured that the Tariffs are set so that they allow the network company to recover its yearly regulated remuneration.

STEP 1

In the first step, we used the MW.mile, the Modulus and the *Zero Counterflow* methods to evaluate the cost of use of the network to allocate to each load. This step can be structured in the following phases:

- in the first place, it is necessary to define a number of generation/load scenarios representative of an year of operation of the system. To this purpose we used 6 base scenarios publicly available in reference [1]. These base scenarios are related to Peak Wet Winter (PWW), Valley Wet Winter (VWW), Peak Dry Winter (PDW), Valley Dry Winter (VDW), Peak Dry Summer (PDS) and Valley Dry Summer (VDS) situations. For each of these 6 scenarios reference [1] includes information about loads and generations, as well as imports and exports through international interconnections;
- these 6 scenarios represented in a poor way the operation along a year. Therefore, they were build 9 other scenarios related to Peak Wet Spring/Autumn, Valley Wet Spring/Autumn, Peak Dry Spring/Autumn, Valley Dry Spring/Autumn, Full Wet Spring/Autumn, Full Dry Spring/Autumn, Full Wet Winter, Full Dry Winter and Full Dry Summer situations;
- the duration of the 15 scenarios was computed according to the legislation regarding the daily number of peak, full and valley hours. They were also considered probabilities of occurring a dry or wet year;
- for each of these 15 scenarios they were run DC power flow studies using the corresponding injection power vector. The branch power flows are necessary since the purpose of the work was to use power-flow based embedded methods. This choice implicitly recognized that the currently used Postage Stamp approach, even though having a voltage discrimination, was poor from a technical and economic points of view. In fact, its average cost basis certainly hide very different situations of nodal injections regarding the effective use of networks;
- the referred MW.mile, Modulus and Zero Counterflow methods also require the knowledge of the contribution of each load or generator to each branch power flow. At this point, a first decision was taken regarding what class of entities would pay the Use of Transmission Network. In line with the present legislation, we decided that final clients or distribution companies connected to this network would pay these Tariffs. In order to compute the contribution of each load – final client or distribution company – to each branch flow it was possible to use the DC based sensitivity coefficients. However, these coefficients are dependent on the selection of the reference bus. This would lead to different amounts to be paid by each load if that reference would change. In order to avoid having to take a difficult and controversial decision, it was decided to use the Generalized Load Distribution Factors, GLDF, as defined in [2]. These coefficients are independent from the reference bus and, differently from the DC sensitivity coefficients, they haven't incremental nature. They depend on the operation conditions of the power system and, as indicated in [2], they translate the global use of some resources by a class of agents – nodal loads as in (1). In this expression, fc_k is the active flow in branch k, $GLDF_{k,j}$ is the Generalized Load Distribution Factor of branch k regarding load L_j;

$$fc_k = \sum_j GLDF_{k,j}.L_j \quad (1)$$

- these coefficients can now be used to compute $fc_k(j)$ representing the contribution of each load L_j to each branch flow fc_k (2);

$$fc_k(j) = GLDF_{k,j}.L_j \quad (2)$$

- using these contributions, they were calculated coefficients T_j translating the cost of using the transmission network to be allocated to a load L_j. These coefficients depend on the allocation method and so expressions (3), (4) and (5) were used considering the MW.mile, Modulus and Zero Counterflow methods. In these expressions and for a system with n components, C_k is the cost of component k, $\overline{fc}_k$ is the transmission capacity of component k and $fc_k(s+)$ is a branch k flow in the same direction of fc_k:

$$T_j = \sum_{k=1}^{n} \frac{C_k}{\overline{fc}_k}.|fc_k(j)| \quad (3)$$

$$T_j = \sum_{k=1}^{n} \frac{C_k}{\sum_s |fc_k(s)|}.|fc_k(j)| \quad (4)$$

$$\begin{cases} T_j = \sum_{k=1}^{n} \frac{C_k}{\sum_s fc_k(s+)} fc_k(j) & \text{for } fc_k(j) > 0 \\ T_j = 0 & \text{for } fc_k(j) \le 0 \end{cases} \quad (5)$$

In Tables I and II we present values for the T_j in some nodes of the Portuguese Transmission Network. These values are related to the corresponding loads in four operation scenarios. The values are also indicated considering the cost allocation method that was used - MW.mile (MWm), Modulus (M) and Zero Counterflow (ZC).

Table I - T_j p.u. (PTE) in 2 scenarios, PWW and PDS.

	Peak Wet Winter			Peak Dry Summer		
Node	MWm	M	ZC	MWm	M	ZC
Mogadouro	5,5	7,0	6,8	6,1	8,5	8,1
Valdigem	67,1	62,8	73,8	47,1	45,3	46,3
Vermoim	215,4	182,5	202,0	213,8	176,5	156,3
Vila Chã	139,8	115,3	133,1	138,7	111,4	116,7
Batalha	115,9	92,9	89,7	124,5	95,8	105,3
Alto Mira	189,2	148,7	133,0	215,0	166,3	188,6
Porto Alto	27,6	23,5	19,3	38,2	29,5	32,6
Tunes	116,5	117,9	88,4	151,1	132,2	120,0

Table II - T_j p.u. (PTE) in 2 scenarios, VWW and VDS.

	Valley Wet Winter			Valley Dry Summer		
Node	MWm	M	ZC	MWm	M	ZC
Mogadouro	3,4	8,4	8,5	2,5	10,1	7,8
Valdigem	22,7	53,6	57,3	12,8	30,1	29,4
Vermoim	77,4	166,3	169,8	76,9	153,5	168,8
Vila Chã	44,6	88,8	98,0	17,2	36,8	26,2
Batalha	48,6	94,4	107,3	42,6	69,9	66,9
Alto Mira	66,7	129,0	117,5	64,0	110,1	108,8
Porto Alto	10,1	21,1	18,7	13,6	22,6	21,8
Tunes	58,4	122,0	67,2	73,0	126,4	104,6

The complete set of results obtained for these coefficients for all 15 scenarios and for all loads is published in reference [3]. The text in Portuguese is publicly available in http://www.erse.pt.

STEP 2

Once the T_j coefficients are computed for each of the three allocation methods and for each of the 15 operation scenarios of the generation/transmission system, it is possible to determine the Tariffs for Use of the Network for each of the three calculation hypotheses that will be characterized in the next paragraphs. Let us recall that 5 of these scenarios are related to valley hours, 5 are related to full and the remaining 5 are related to peak hours. In the following hypotheses the peak power subjected to tariff is defined as the maximum value of the mean power measured along a period of 15 minutes on a certain tariff period.

Hypothesis 1

In this hypothesis, we admitted there would be one only tariff to remunerate the use of the network corresponding to a power tariff. The amount to pay is proportional to the peak power measured on off valley hours. The value of this tariff is computed using the T_j values obtained in the 10 off-valley scenarios.

Hypothesis 2

In the second Hypothesis, we admitted there would be two power tariffs related to the wet and dry periods. We also admitted that the amount to be paid would depend on the peak powers measured on off valley hours on the wet and dry periods. However, when determining the values of the tariffs we used the T_j values computed for all the referred 15 scenarios, both on valley and off-valley hours.

Hypothesis 3

In the third Hypothesis, we considered four power tariffs for use of the network related to the wet and dry tariff periods discriminated for the valley and off valley hours. We also admitted that the amounts to be paid would depend on the peak powers measured on off valley and valley hours in the wet and dry periods. When determining the values of the tariffs we used the T_j values computed for all the referred 15 scenarios, both on valley and off-valley hours.

In any of these hypotheses and regardless of the cost allocation method used to compute the T_j values, the tariffs were calculated so that they would provide the recovery of the whole yearly regulated remuneration defined for the transmission company.

In order to obtain the values of the tariffs in each of those three hypotheses, and reflecting the scenarios of the generation/transmission system used in each of them, we considered the following phases:

i) computation of the weighted average of the T_j values for the scenarios related to peak hours, full hours and valley hours. This calculation was performed considering the duration of each of these periods along the week as defined in the Tariff Regulation. This calculation also considered the scenarios of the generation/transmission system used in

each of the three hypotheses. As an example, in Hypothesis 2, for the Winter and Spring scenarios we used the coefficients 25/168 for peak hours, 67/168 for full hours and 76/168 for valley hours. In the Autumn and Summer scenarios we used the coefficients 15/168 for peak hours, 77/168 for full hours and 76/168 for valley hours;

ii) calculation of the weighted average of the T_j values considering the probabilities assigned to a dry year (rain fall inferior than the average) and wet year (rain fall larger than the average) in the Winter, Spring and Autumn. In our simulations we admitted 0,5 for these probabilities;

iii) calculation of the T_j values for the yearly wet and dry periods defined in the Tariff Regulation. Using the T_j values computed in ii) for the corresponding Hypothesis, it is now possible to compute the T_{jW} values for the wet period as the weighted average of the T_j values for Winter and Spring. In a similar way, the T_{jD} values for the dry period correspond to the weighted average of the T_j values for Autumn and Summer. For the third Hypothesis, there are four values to be calculated: $T_{jW,OV}$, $T_{jW,V}$, $T_{jD,OV}$ and $T_{jD,V}$. They correspond to weighted averages of the T_j values for the wet off-valley period, the wet valley period, dry off-valley period and dry valley period;

iv) calculation of the CT_j values representing the amount of the global yearly regulated remuneration that shall be provided by each load L_j due to the use of the network in the periods in each calculation Hypothesis.

Let us assume that CT is the remuneration of the transmission company to recover by the application of the Tariffs for Use of the Transmission Network. Let us also admit that each period – wet or dry – will be responsible for the recovery of the same amount. These amounts will be represented by CT_W for the wet period and CT_D for the dry, so that their addition is CT.

Hypotheses 1 and 2: The remunerations to be paid by the load L_j in each period, wet - CT_{jW}, and dry - CT_{jD}, are given by (6) and (7).

$$CT_{jW} = CT_W \cdot \frac{T_{jW}}{\sum_{\text{all loads } l} T_{lW}} \tag{6}$$

$$CT_{jD} = CT_D \cdot \frac{T_{jD}}{\sum_{\text{all loads } l} T_{lD}} \tag{7}$$

The global amount CT_j paid to the load L_j is the sum of the remunerations in the wet and dry periods (8).

$$CT_j = CT_{jW} + CT_{jD} \tag{8}$$

One should notice that the values T_{jW} and T_{jD} computed for the Hypotheses 1 and 2 are different. In fact, in Hypothesis 1 they are considered only the 10 off-valley scenarios while in Hypothesis 2 we considered all 15 valley and off-valley scenarios.

Hypothesis 3: In this case, expression (9) to (12) give the amounts to be paid by each load L_j in the wet period in the off-valley hours $CT_{jW,OV}$, and in the valley hours $CT_{jW,V}$, and in the dry period in the off-valley hours $CT_{jD,OV}$, and valley hours $CT_{jD,V}$.

$$CT_{jW,OV} = CT_{W,OV} \cdot \frac{T_{jW,OV}}{\sum_{\text{all loads } l} T_{lW,OV}} \tag{9}$$

$$CT_{jW,V} = CT_{W,V} \cdot \frac{T_{jW,V}}{\sum_{\text{all loads } l} T_{lW,V}} \tag{10}$$

$$CT_{jD,OV} = CT_{D,OV} \cdot \frac{T_{jD,OV}}{\sum_{\text{all loads } l} T_{lD,OV}} \tag{11}$$

$$CT_{jD,V} = CT_{D,V} \cdot \frac{T_{jD,V}}{\sum_{\text{all loads } l} T_{lD,V}} \tag{12}$$

In these expressions, $CT_{W,OV}$, $CT_{W,V}$, $CT_{D,OV}$ and $CT_{D,V}$, represent parts of the global yearly regulated remuneration CT, in this case related to the off-valley and valley hours both on the wet and dry periods. The split of the remuneration to be recovered in each period was performed considering that it should be equal in the wet and dry periods. In each of them, 62,5% of the remuneration will be recovered in the off-valley hours and 37,5% in the valley hours. These percentages were obtained considering the amounts of energy to be subjected to tariffs in the off-valley hours and in the valley hours, according to values that (by the time this study was performed) were estimated for the year 2000 in the wet and dry periods. In a similar way to what was referred for Hypotheses 1 and 2 the sum of the amounts $CT_{W,OV}$, $CT_{W,V}$, $CT_{D,OV}$ and $CT_{D,V}$, is equal to the global regulated remuneration CT.

v) the Tariff for Use of the Network corresponds to the monthly amount to be paid by the load L_j connected to node j. This value is calculated dividing the remuneration to be recovered in the tariff period under consideration by the number of months in that period and by the average value of the peak powers in those months. According to this reasoning we have:

Hypothesis 1 – the value of the monthly tariff, per unit of the load L_j, is calculated dividing the CT_j value by 12 and by the average value of the peak powers in the 12 months. The average of the peak powers was obtained considering the powers in all the available scenarios for the off-valley hours;

Hypothesis 2 – the values of the monthly tariffs, per unit of the load L_j, for the wet and dry periods, were obtained dividing the remunerations $CT_{j,W}$ and $CT_{j,D}$ by 6 and by the average of the peak powers in each set of months included in those periods. For each period, each of these

two average values was obtained considering the powers in each available scenario only for the off-valley hours;

Hypothesis 3 – the values of the monthly tariffs, per unit of the load L_j, for the wet and dry periods and for the off-valley and valley hours, were obtained dividing the remunerations $CT_{jW,OV}$, $CT_{jW,V}$, $CT_{jD,OV}$ and $CT_{jD,V}$ by 6 and by the average of the peak powers in the wet and dry periods and in the off-valley and valley hours. The monthly peak power in the off valley hours, in the wet and dry periods, corresponds to the average of the powers in all off-valley available scenarios. Regarding the valley hours and for the wet and dry periods, the peak monthly powers were obtained as the average of the powers in all valley available scenarios.

III. RESULTS ON THE PORTUGUESE TRANSMISSION GRID

The approach that was described in Section II was tested considering the 15 scenarios defined for the Portuguese generation/transmission system. We considered the three calculation hypotheses above designated as 1, 2 and 3 and we used the MW.mile, the Modulus and the Zero Counterflow cost allocation methods to assign costs to the loads. The complete results that were obtained in this study, for all load nodes of the transmission Portuguese network, are published in [3] and this report is publicly available in http://www.erse.pt. In this paper, in order to illustrate the application of the described approach, we present the tariffs obtained for the same set of nodes for the different calculation hypotheses and for each of the three cost allocation methods. Tables III to VI include the values obtained for the tariffs per unit of load connected to each node.

In Table III we present the values of the Tariffs for Use of the Network according to Hypothesis 1. In columns 1 and 2 we indicate the node and the peak power subjected to tarification in this hypothesis. In the third, fourth and fifth columns are the values of the tariffs obtained using the MW.mile, the Modulus and the Zero Counterflow cost allocation methods.

Table III –Power tariffs for Hypothesis 1.

Unique Power Tariff (PTE/kW.month)				
Node	Peak Power (MW)	MWm	M	ZC
Mogadouro	6,74	498,88	822,53	624,54
Valdigem	93,11	372,02	413,13	427,50
Vermoim	357,76	347,61	335,22	347,85
Vila Chã	186,16	413,43	395,31	347,52
Batalha	208,76	344,65	311,00	337,81
Alto Mira	356,16	347,94	316,17	344,92
Porto Alto	46,38	412,67	383,47	404,15
Tunes	149,04	547,99	563,62	486,18

Table IV – Power tariffs for Hypothesis 2.

Power Tariffs for Wet and Dry Periods (PTE/kW.month)						
	MWm		M		ZC	
Node	Wet	Dry	Wet	Dry	Wet	Dry
Mogadouro	547,0	541,6	895,1	977,0	761,4	719,2
Valdigem	347,7	353,7	368,0	400,2	387,1	406,9
Vermoim	328,8	348,1	318,9	346,5	333,5	372,6
Vila Chã	374,9	366,8	344,7	337,3	322,0	273,9
Batalha	337,7	350,5	304,6	313,6	325,8	334,5
Alto Mira	326,7	347,0	295,6	313,9	305,3	337,4
Porto Alto	388,0	417,6	369,7	378,6	363,8	392,0
Tunes	564,3	613,3	593,7	614,3	485,4	527,2

In Table IV we present results obtained for the Tariffs for Use of the Network considering Hypothesis 2. In this case, we indicate the values of the tariffs for the wet and dry periods obtained considering the three referred cost allocation methods.

Table V includes results for the Tariffs for Use of the Network considering Hypothesis 3. This Table includes values of the tariffs for the wet period and for the three cost allocation methods. In each of these three cases, we indicate the values of the tariffs due in each node on the off-valley and on valley hours. In a similar way, Table VI includes the values of the tariffs obtained in the same nodes, for each of the three cost allocation methods, both on off-valley and valley hours, but now for the dry period.

Table V – Power tariffs for Hypothesis 3 in the Wet Period.

Power Tariffs for the Off-Valley (OV) and Valley (V) Periods (PTE/kW.month)						
	MWm		M		ZC	
Node	OV	V	OV	V	OV	V
Mogadouro	306,1	370,5	491,6	564,3	421,8	476,5
Valdigem	230,0	307,6	247,1	341,1	262,1	354,5
Vermoim	212,4	303,2	202,8	312,1	210,3	330,6
Vila Chã	251,7	319,7	238,8	306,3	225,5	280,9
Batalha	209,1	257,0	188,6	229,8	201,1	247,0
Alto Mira	208,2	280,5	188,5	259,5	198,5	261,1
Porto Alto	246,7	319,2	235,3	310,2	238,4	293,1
Tunes	325,5	406,5	345,7	395,1	289,4	314,7

Table VI – Power tariffs for Hypothesis 3 in the Dry Period.

Power Tariffs for the Off Valley (OV) and Valley (V) Periods (PTE/kW.month)						
	MWm		M		ZC	
Node	OV	V	OV	V	OV	V
Mogadouro	317,8	379,3	537,7	700,1	357,2	566,5
Valdigem	235,7	304,8	272,5	360,7	273,7	373,9
Vermoim	222,6	311,3	216,9	328,9	225,2	369,9
Vila Chã	265,8	313,7	256,2	327,4	208,0	265,5
Batalha	222,1	259,4	200,4	233,7	221,7	235,8
Alto Mira	227,3	295,3	207,2	279,5	233,7	277,3
Porto Alto	268,3	333,0	243,8	311,7	265,8	297,4
Tunes	359,2	436,2	358,8	417,4	318,1	343,9

IV. DISCUSSION

As it is well understood, given their different conceptions, the three cost allocation methods used to compute the T_j values lead to different results [4, 5]. Let us recall that the T_j values translate the cost of using the network equipments to be paid by load L_j connected to node j.

In fact, in the MW.mile method the cost of using each component of the network by load L_j is measured proportionally to the amount of its capacity or nominal power that is used by that load. In the Modulus method, the referred cost is measured proportionally to the sum of the modulus of the powers flowing in that component due to all system loads. Finally, in the Zero Counterflow method the cost of using each component of the network by load L_j is measured proportionally to the sum of the powers flowing due to all system loads and in the same direction of the resulting power flow in that component.

The adoption of each of these three measures of the use of network by each load displays both advantages and disadvantages. Regarding the MW.mile and the Modulus

methods, all loads originating contributions to power flowing in each network component are treated in the same way. In particular, there is no difference between loads having contributions in the direction opposite to the resulting flow in a component, thus alleviating congestion, and the loads having contributions in the same direction of the resulting flow.

Differently, the Zero Counterflow method favours the loads connected to nodes such that their contribution to branch power flows have a direction contrary to the resulting one. In these cases, the cost to be assigned to those loads regarding such equipments is zero. However, this appealing treatment of loads in this situation is the reason explaining discontinuities in the costs of using network components by each load. This is due to the possible reversions of direction of branch flows reflecting variations in nodal loads or in the adopted generation /transmission strategies. In Tables I and II we can observe the variations, in same cases large ones, of the T_j values when passing from one method to another, within each scenario.

From a conceptual point of view, the process of calculating the remuneration to be provided by load L_j has a common point in all the three described Hypotheses. These three sets of tariffs are fixed so that the whole amount to be recovered equals the global yearly regulated remuneration. Regarding the results obtained for the tariffs, one can notice another common situation. The tariffs, for the above three tariff Hypotheses, display a large geographic dispersion. This translates more closely from a technical point of view the way the transmission network is used.

In Hypothesis 1 and 2, the resulting tariffs clearly favour consumptions on valley hours when making the amounts to pay proportional to the peak power on off-valley hours. However, in Hypothesis 1 the tariffs are calculated only considering the cost of using the network equipments in off-valley hours (10 out of the 15 scenarios). Differently, in hypothesis 2, we consider the costs of using the network equipments both on valley and off-valley hours (all the 15 available scenarios).

Apart from the above geographic dispersion, it is worth noticing that in hypotheses 2 and 3 the tariffs display large variations when going from the values in the wet to the values in the dry period. This is explained considering the generation mix of the Portuguese system. In our system, about 40% of the power is installed in hydro plants most of them located in the north. The majority of the remaining 60% corresponds to thermal plants most of them in the south part of the country. This leads to very different operation situations of the generation/transmission system in the wet and dry scenarios. Typically, the flows (value and direction) are different in the wet and dry periods leading to diverse uses of the network by each load, thus explaining those results.

Hypothesis 3 includes both valley and off-valley hours and the tariffs were obtained considering that 37,5% of the yearly regulated remuneration should be recovered in valley hours, as referred Section II. Since the peak powers are more reduced in valley hours, the price per kW in these hours is higher according to the third hypothesis and for any of the three used cost allocation methods. This wouldn't favour consumptions in valley hours. Therefore, the referred split of the remuneration between valley and off-valley hours should be changed in order to reduce the amount to be recovered in valleys.

In this study, we have only considered tariff terms dependent on the active power. However, the described approach can be equally used to include tariff terms dependent from reactive energy. Among other issues, this would require the definition of the percentages of the global yearly regulated remuneration to be recovered by the active power tariff terms and by the reactive energy tariff terms.

III. CONCLUSIONS

As referred in the beginning, the consultancy study on which this paper is based was prepared as a contribution to the revision process of the regulatory texts in force in the Portuguese electric sector. Therefore, when selecting cost allocation methods to be tested, it was not our concern to adhere in a strict way to the current legislation.

One of the most important issues that have to be discussed corresponds to a tariff uniformity principle introduced by the legislation of 1995. That principle states that "in every moment, the Tariff Scheme in use is applied in an universal way to all final clients of the Electric Public System - SEP". The current Tariffs for Use of Networks rigidly comply with this principle when adopting the Postage Stamp approach to all entities not only of SEP but also of SEI and when only admitting a differentiation by voltage level. It is clear for us that the application of any of three tested methods would be controversial given that principle. In any case, it is not clear for us that the above statement leads to geographically uniform tariffs since one could argue that uniform tariffs for all clients connected to the same node would also correspond to a non-discriminatory treatment. In any case, the proximity of a new regulatory period and the revision of the current regulations are the right moments to consider the advantages and drawbacks of cost allocation approaches alternative to the currently used one.

Specifically regarding the three cost allocation methods, the Zero Counterflow has the disadvantage of leading to tariff discontinuities. This would turn the tariffs less predictable and eventually less understandable to network users. According to this reasoning, if the uniformity tariff principle is turned more flexible, it is our opinion that approaches based on the MW.mile or the Modulus are more attractive. Among these two methods, the Modulus method reflects the use of the network in a more fair way since the contributions of all loads are equally treated.

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