FROM SHORT TO LONG TERM MARGINAL PRICES – ADVANTAGES AND DRAWBACKS

A. S. Braga
Instituto Politécnico da Guarda
Escola Superior de Tecnologia e Gestão
Av. Francisco Sá Carneiro, no. 50, 6300 559 Guarda, Portugal
email: asdbraga@ipg.pt

João Tomé Saraiva (*)
INESC Porto and FEUP/DEEC
Rua Roberto Frias 378, 4200 465 Porto, Portugal
phone +351.22.5081880 fax: +351.22.2094050
email: jsaraiva@fe.up.pt

ABSTRACT: In this paper we present models to compute short term and long term nodal marginal prices in transmission networks. Short term marginal prices are evaluated as sub-products of operation optimization problems and lead to a marginal based remuneration that is typically small when compared to the regulated amount. To address this Revenue Reconciliation Problem we developed a long term expansion planning problem in the scope of which long term nodal marginal prices are computed. The algorithm uses Simulated Annealing to take into account the discrete nature of several decisions and is able to consider a multi-period dynamic approach. The paper presents results from some case studies in order to clarify the advantages and drawbacks of these methodologies.

Keywords: Reregulation, Transmission Providers, Remunerations, Tariffs, Short Term Marginal Prices, Long Term Marginal Prices.

I. INTRODUCTION

The reregulation of power systems started in Chile back in the 80th and continued in England & Wales in the beginning of the 90th and in many other European and American countries as well as in Australia and New Zealand in the last decade. This move is leading to the unbundling of the original vertical utilities into several activities. Among them one can now clearly identify:

- Generation activities – this includes electricity generation under normal competitive regime, electricity generation under any special tariff regime (namely including extra payments to renewables) and the supply of ancillary services. The supply of several ancillary services can be achieved in terms of specific markets or can be considered as a mandatory condition to be an agent in the electricity market;
- Network activities – it comprises the transmission sector and the distribution wiring sector supposing that it is decoupled from the commercial relationship with end consumers. These functions include operation, maintenance and expansion of the networks and are usually assigned to specific network companies that act under a monopoly basis given that it is not feasible to duplicate lines in the same geographical area;
- Transactions – this activity enables the commercial relationship between generation companies, for one side, and eligible consumers and retailers, on the other. This relationship can be organized in terms of centralized Pool markets or via Bilateral Contracts either having a physical or financial nature. This activity can also be complemented by metering and billing activities eventually provided by specific companies;
- Technical and Regulatory Coordination activities – the technical supervision and coordination activities are provided by the Independent System Operator, ISO. In some countries – namely in European ones – this can be merged with the transmission provider thus leading to the concept of a Transmission System Operator, TSO. At a regulatory level, there are crucial areas of the system that are not subjected to competition – namely network activities – thus requiring being enforced by some regulatory framework designed and supervised by Regulatory Entities.

This decoupling of activities lead to a number of challenges and changes in the way power systems are operated, maintained and expanded. The expansion of power systems is being under the highlights of researchers, regulatory entities and are the concern of consumers given the problems extensively analyzed that occurred in California, in Brazil and also in Spain (with the occurrence of system price spikes namely in December 2001). Expansion must be seen both from the point of view of the generation system as well as from the point of view of the transmission network. Specifically when considering the transmission network, it must be designed a regulatory framework that encourages transmission providers to invest, so that congestion does not correspond to a permanent state of the system thus distorting the results from a purely economic way of organizing the generation and the load. This also means that Tariffs for the Use of Transmission Networks must be adequately conceived so that they remunerate not only short term costs but also long term investment costs while allocating all those costs in a efficient and fair way to users [1, 2, 3, 4, 5].

This paper reports the results of the research obtained so far in the scope of the PhD work developed by the first author. We are specially concerned in extending the concept of short term marginal prices enlarging the horizon under study in terms of a transmission expansion planning problem. This will enable us to identify the most adequate transmission expansion plan and to derive the related Long Term Marginal Prices that will be able to remunerate long term investments as well as short term operational costs. This approach inherently addresses a number of criticisms pointed to short term marginal based tariffs. Long term prices are less volatile, the corresponding marginal remuneration accommodates the costs of the companies and fits better to the regulated remuneration so that the well known Revenue Reconciliation Problem is minimized, and the expansion problem is married with the tariffs for use of the network. This means that larger investments lead to fewer congestion and to larger tariffs.

The paper is organized as follows. After this Introductory section, Section II gives some more details about regulatory issues and tariff approaches described in the literature, Section III details models to compute short term marginal prices and Section IV describes the model developed to compute long term marginal prices. Section V includes results from two Case Studies. The first one reports the results obtained for the 400/220/150 kV Portuguese transmission network considering short term marginal prices. The second one uses a small test system on which we performed several expansion planning studies using the model of Section IV. Finally, section VI presents some conclusions and directions of future research.

II. REGULATION / EXPANSION / TARIFFS

The strategies adopted to regulate transmission and distribution wiring companies are influenced by the technical and economic performance of companies, by their efficiency and certainly by the share of their costs in the price of the final product. In this scope, transmission and distribution companies are generally in very different positions. Transmission companies are usually much more efficient, their investment requirements are usually not so large, quality of service indices are better and transmission costs have a share of around 5% in the electricity price. In several countries, this justifies the adoption of Cost of Service/Rate of Return regulatory strategies to frame these companies. According to this approach, the regulated companies send the estimated costs for the next year to the regulatory entity as well as the assets in operation and on which a remuneration rate is applied. If accepted, this leads to the amount to recover by the Tariffs for the Use of Transmission Networks. In any case, in other countries some type of Incentives Regulation is used not only on the distribution wiring sector but also on the transmission sector, recognizing that it is necessary to send signals to go on improving economic efficiency. England and Wales is only one example where a RPI-X strategy is in force.

A crucial aspect is related with the treatment given to long term investment costs. The adopted regulatory approach must recognize short term operation costs as well as long term ones so that transmission companies are not discouraged from investing in transmission expansion. A possible way of tackling this problem is currently in force in Portugal. In 2001 the Portuguese TSO and the Regulatory Board agreed on a number of quality and security indices to guide the expansion planning of the transmission network. After that, the TSO prepared and submitted a 6 year expansion plan of the network in order to be approved by the Regulatory Board. This plan is refreshed every 2 years from now on and if accepted it corresponds to a tacit acceptation of the evolution of investment costs along the planning horizon by the Regulatory Board. In a certain way, the acceptance of this plan much determines the evolution of the Tariffs for the Use of Networks since those investments costs are already accepted and approved by the Regulatory Board. This approach is certainly in the right direction in terms of giving a longer term and stable horizon to the TSO.

III. EVALUATION OF SHORT TERM MARGINAL PRICES

A. General Aspects

Short term marginal prices, STMP, can be defined as the variation of the cost function of the related optimization problem regarding a variation of the load [6]. When considering a model of the network, it becomes clear that these prices will vary from node to node namely because power systems have predominantly generation areas as well as typically load areas, branches have transmission limits and have losses. This means that the STMP of electricity in node k, ρ_k, is given by (1). In this expression, f is the objective function of the optimization problem and Pl_k is the load in node k. Apart from this geographic dispersion, STMP are also very dependent on the topology of the system in operation, on outages, on the generation dispatch policy, on generation costs and on the load level and its distribution along system nodes. All these issues explain the volatility of STMP leading to one of the major difficulties of implementation of practical tariff systems based on them. This volatility and time dependence leads to the concept of Spot Price of electricity, corresponding to the STMP at node k and at instant t.

$$\rho_k = \frac{\partial f}{\partial Pl_k} \tag{1}$$

In any case, the interest of using STMP comes from the fact that they are related with dual variables of the optimization problem. Assuming a continuous and linear problem the Strong Primal Dual Theorem indicates that when the optimum is reached, the value of the primal objective function equals the value of the dual one. This leads to the economic interpretation of the dual problem meaning that the cost of production of a set of items can be entirely recovered if the usage of the resources is priced according to marginal prices. In this sense, dual variables are also known as shadow or dual prices since they represent the optimum economic signal sent to the system and leading to an equilibrium between costs and remunerations.

For tariff purposes in power systems it is usually accepted the following rule: generators are paid and loads pay the electricity at the marginal price at the node they are connected to. Once this rule is accepted, it is easily understood that given the geographic dispersion of STMP this leads to a surplus of remuneration – the Marginal Based Remuneration, MBR, given by (2) – that can be assigned to the transmission provider. In this expression, we assumed that STMP were computed for a load scenario or system topology i. This means that if nsc is the number of load scenarios to consider along a year, then the yearly MBR is given by (3) in which T_i is the duration of scenario i.

$$MBR_i = \sum_{k=1}^{NNodes} \rho_{ik} . (Pl_{ik} - P_{gik}) \ \$/h \tag{2}$$

$$MBR = \sum_{i=1}^{nsc} MBR_i = \sum_{i=1}^{nsc} T_i \sum_{k=1}^{NNodes} \rho_{ik}.(Pl_{ik} - P_{gik})\,\$ \tag{3}$$

STMP can be computed using different models that are described in the literature [7, 8, 9]. Among them, we will detail two DC based models in the next sections.

B. Model A

In this model, one aims at minimizing the generation cost function f in which we considered a penalty term G to prevent power not supplied, PNS, until a reasonable level. The formulation includes a global balance generation/load equation (5), generation (6), PNS (7) and branch flow (8 and 9) limit constraints. In constraints (8) and (9) a_{bk} is the DC sensitivity coefficient relating the flow in branch b (extreme nodes m and n) with the injected power in node k.

$$\min f = \sum c_k.Pg_k + G.\sum PNS_k \tag{4}$$

$$\sum Pg_k + \sum PNS_k = \sum Pl_k \tag{5}$$

$$Pg_k^{min} \le Pg_k \le Pg_k^{max} \tag{6}$$

$$PNS_k \le Pl_k \tag{7}$$

$$\sum a_{bk}.(Pg_k + PNS_k - Pl_k) \le P_b^{max} \tag{8}$$

$$\sum a_{bk}.(Pg_k + PNS_k - Pl_k) \ge P_b^{min} \tag{9}$$

This formulation includes one the main reasons for the geographic dispersion of STMP, that is a model of the network and thus, the geographic dispersion of generators and loads and branch flow limits. However, branch losses also have to be included so that STMP are more realistically evaluated. An estimate of branch losses can be considered following the algorithm summarized in the next paragraphs.

Algorithm

i) Run an initial dispatch using (4) to (9);
ii) Compute the voltage phases according to the DC model;
iii) Estimate branch active losses using (10);

$$Loss_{mn} \approx 2.g_{mn}.(1 - \cos\theta_{mn}) \tag{10}$$

iv) Add half of the losses in branch b with extreme nodes m and n, to the loads in nodes m and n;
v) Run a new dispatch using (4) to (9);
vi) Compute the voltage phases according to the DC model;
vii) End if the difference of voltage phases in all nodes is smaller than a specified threshold. If not, return to iii).

Once the above algorithm converges, the STMP in node k can be computed using (11). In this expression, ρ_{ik} is the STMP at node k for a scenario i, γ_i is the Lagrange multiplier of the balance equation (5), Pl_{ik} is the active load at node k in scenario i, P_{mn} is the active flow from node m to node n, μ_{mn} 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 active losses at all system branches at scenario i.

$$\rho_{ik} = \gamma_i + \gamma_i.\frac{\partial Loss}{\partial Pl_{ik}} - \sum \mu_{mn}.\frac{\partial Pmn}{\partial Pl_{ik}} + \sigma_{ik} \tag{11}$$

From this expression it becomes evident that losses and transmission congestion are the marginal resources of transmission companies. In fact, they are responsible for the geographic dispersion of STMP and thus for a more or less significant MBR value. If a transmission company has a loss less ideal network and invested as much as necessary so that congestion never occurs whatever load and generation scenario is considered, then STMP are the same in all nodes and MBR is zero. On the contrary, a lazy transmission company would have large losses and a large number of congested lines leading to a significative number of μ_{mn} non zero dual variables. In this case, this lazy company would be prized with a large MBR. This perverse effect has to be counteracted by adequately regulate transmission companies and by establishing Quality of Service requirements that prevent this lazy behavior.

C. Model B

Model A has a major drawback since it requires building and inverting the DC model admittance matrix, thus requiring selecting a reference node. When considering the compensation of marginal losses, this node also becomes a slack node meaning that STMP computed with Model A depend on the selected reference+slack node. Model B does not require inverting the referred matrix and it includes as much balance equations as nodes so that STMP are not dependent on the reference node. The price to pay is that the components of STMP, as depicted in expression (11), will no longer be isolated.

Model B assumes that branch losses are approximated by (12) that depends on the phase difference across the branch. In this expression the coefficients CL^1 and CL^2 are given by (13) and (14) and are calculated at the current operation point p characterized by voltage phases.

$$Loss_{mn} \approx CL^1_{mn} + CL^2_{mn}.\theta_{mn} \tag{12}$$

$$CL^1_{mn} = 2.g_{mn}.(1 - \cos\theta^p_{mn}) - (2.g_{mn}.\sin\theta^p_{mn}).\theta^p_{mn} \tag{13}$$

$$CL^2_{mn} = 2.g_{mn}.\sin\theta^p_{mn} \tag{14}$$

As in Model A, half of the losses in branch mn are added to the load in each extreme bus leading to (15) to (19). In this formulation, there are as many nodal balance equations as system nodes assuming that BDC_{kj} is the element in line k/column j of the DC admittance matrix. Constraints (17) and (18) are similar to the ones in Model A and (19) imposes bounds on branch flows directly in terms of the phase difference across each branch. It should be emphasized that voltage phases are now variables of the problem.

$$\min f = \sum c_k.Pg_k + G.\sum PNS_k \tag{15}$$

$$Pg_k + PNS_k - \sum_j BDC_{kj}.\theta_j - \sum_j \frac{CL^2_{kj}}{2}\theta_{kj} = Pl_k + \sum_j \frac{CL^1_{kj}}{2} \tag{16}$$

$$Pg_k^{min} \le Pg_k \le Pg_k^{max} \tag{17}$$

$$PNS_k \le Pl_k \tag{18}$$

$$P_b^{min} \le \frac{\theta_{mn}}{x_{mn}} \le P_b^{max} \tag{19}$$

In the first iteration, voltage phases are zero, so that Model B is in fact equivalent to A. Once the first dispatch is complete, one gets the values of the voltage phases so that the coefficients (13) and (14) can be computed for each branch. This means that a new dispatch can be run now including the linear estimate of branch losses. As for Model A, the algorithm finishes when, for all nodes, the difference of voltage phases is smaller than a specified threshold.

Considering this model, the impact on the objective function from varying the load in node k only comes from the dual variables of constraints (16) and (18) related with node k. This means that the STMP in node k is now given by (20). In this expression γ_k and σ_k are the dual variables of constraints (16) and (18) related with node k.

$$\rho_k = \frac{\partial f}{\partial Pl_k} = \gamma_k + \sigma_k \tag{20}$$

IV. EVALUATION OF LONG TERM MARGINAL PRICES

A. General Issues

Differently from STMP, Long Term Marginal Prices – LTMP – take into account not only operational costs – for instance related with branch losses and congestion – but also investment expansion costs. This means the formulation and the algorithm adopted to solve it have to deal with the two time scales just referred. Apart from that, the transmission expansion planning problem deals with the selection of the most adequate equipments or lines to build along the planning horizon. This means we have a discrete set of decision variables that turn the entire formulation into the field of discrete non continuous optimization problems. Expansion planning problems also have to deal with the uncertainty in terms of nodal load evolution and in most cases with several and most usually contradictory criteria. This finally turns the problem into a multi-criteria discrete non continuous one. In this Section we will describe a formulation and a solution algorithm that does not yet address all these questions but that corresponds to a step in this direction. This formulation and the solution algorithm are under development so that we expect new reports in the near future.

B. Formulation and Algorithm

To take into account the discrete nature of expansion planning decisions we adopted a meta-heuristic that inherently allows us to search the solution space without having to turn variables representing the branch capacities continuous. Specifically, we used Simulated Annealing [10] considering the above referred feature and its flexibility in terms of dealing with several objectives and constraints and its easiness of programming. The algorithm to be described only considers 1 planning interval and a common load increase affecting all nodes on that interval.

<u>Simulated Annealing Algorithm</u>

i) Consider the current transmission/generation system as the initial topology and denote it as x^o;
ii) Analyze the current solution:
   a. compute the investment costs, IC, if any;
   b. solve an optimization problem according to the formulation (4) to (9) in order to evaluate the short term operation costs, OC, related with the current topology;
   c. build the Evaluation Function, EF, by (21);
   $$EF^o = IC^o + OC^o \tag{21}$$
   d. assign EF^o to EF^{opt} and to $EF^{current}$;
   e. assign x^o to x^{opt} and to $x^{current}$;
   f. set the iteration counter, ic, to 1;
   g. set the worse solution counter, wsc, at 0;
iii) Identify a new topology, selected in the neighborhood of the current one - sample a new installation to be built, among the ones in a list of possible works, or to decommissioned, among the existing ones. This topology is denoted as x^{new};
iv) Analyze the new solution by computing OC^{new} and IC^{new} and obtain EF^{new};
v) If $EF^{new} < EF^{opt}$ then
   a. assign EF^{new} to EF^{opt} and to $EF^{current}$;
   b. assign x^{new} to x^{opt} and to $x^{current}$;
   c. set the worse solution counter, wsc, at 0;
vi) If $EF^{new} \geq EF^{opt}$ then
   a. get a random number $p \in [0,0;1,0]$;
   b. compute the probability of accepting worse solutions $p(x^{new})$ by (22);
   $$p(x^{new}) = e^{\frac{EF^{current} - EF^{new}}{K.T}} \tag{22}$$
   c. if $p \leq p(x^{new})$ then assign x^{new} to $x^{current}$ and EF^{new} to $EF^{current}$;
   d. increase the worse solution counter, wsc, by 1;
vii) If wsc is larger than a specified maximum number of iterations without improvements than go to ix);
viii) If the iteration counter ic is larger than the maximum number of iterations per temperature level then:
   a. decrease the temperature level T by a rate α smaller then 1.0;
   b. if the new temperature level is smaller then the minimum allowed temperature then go to ix);
   c. set the iteration counter ic to 1;
   Else, increase the iteration counter ic by 1 and go to iii);
ix) End.

Once the algorithm converges, one identifies the most adequate plan in view of the adopted Evaluation Function. The general expression (1) or the more specific and model dependent expressions (11) and (20) can not be used to compute LTMP. The main reason for this is that the expansion planning problem has a non continuous nature that turns it impossible to use derivates as in (1). Expressions (11) and (20) are only particular ways of computing (1) if models A or B are used. Therefore and according to the general ideas in [11] we used (23) to compute LMTP. For node k, this means that the load Pl_k is increased by ΔPl_k and the expansion planning algorithm is run once again to identify the most adequate plan. Once this is done, the variations of operational costs and investment costs, ΔOC and ΔIC, regarding the initial solution is obtained leading to $LTMP_k$.

$$LTMP_k = \frac{\Delta EF}{\Delta Pl_k} = \frac{\Delta OC}{\Delta Pl_k} + \frac{\Delta IC}{\Delta Pl_k} \tag{23}$$

V. CASE STUDIES

A. Case Study Using the Portuguese Transmission Network

In the scope of the revision of the Tariff Regulation in force since 1998, a Research Team of INESC Porto concluded a consultancy study under a contract with ERSE – the Portuguese Regulatory Board for Energy Services – to estimate the Marginal Based Remuneration of the Portuguese TSO using STMP. The complete conclusions of this study are reported in [12] and some topics are included in [13, 14].

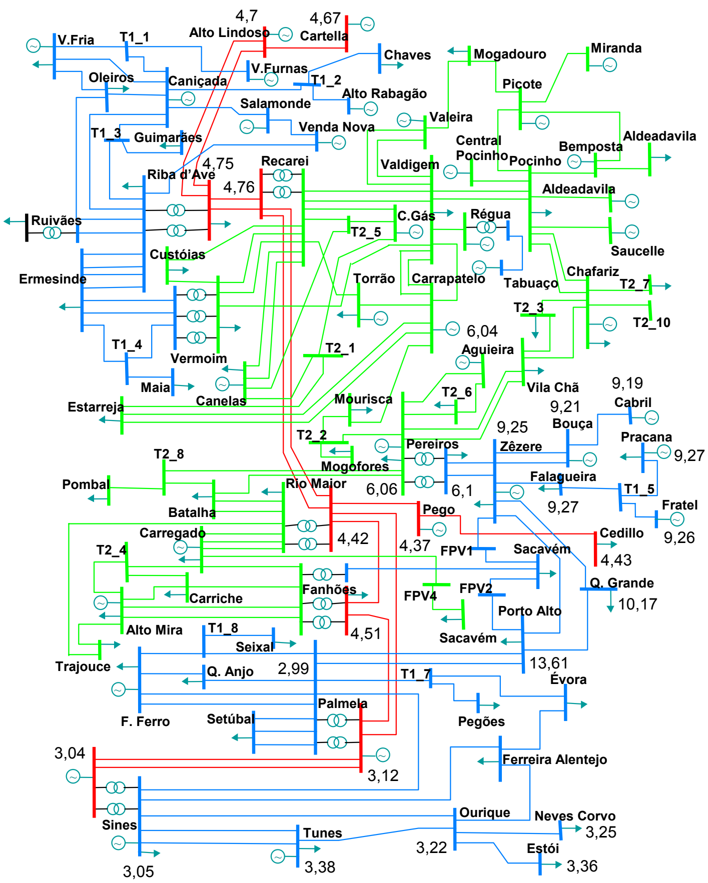

Fig. 1 – 400/220/150 kV Portuguese transmission system with marginal prices in some nodes ($/kWh) for the Peak Dry Summer, PDS, scenario.

In this study, we considered 15 generation/load scenarios for 1998 that characterize the Portuguese generation and transmission systems. Six of these scenarios were publicly available and the rest were built in order to turn the available information less discrete. The scenarios involved peak, full and valley hours, wet and dry conditions and summer, autumn, winter and spring seasons. For each of them, we computed STMP in each node using Model A of Section III. The duration of each scenario was obtained considering the indications included in the Tariff Regulation and using a 0.5 probability for wet or dry conditions. As an example, Figure 1 depicts the one line diagram of the 400/220/150 kV transmission system indicating the nodal prices for some nodes assuming the Peak Dry Summer – PDS – scenario.

Table I – 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

For each scenario, Table I includes the per hour remuneration obtained using expression (2) and the STMP of that scenario, the duration T_i of each scenario and the remuneration of each scenario as the product of each per hour remuneration by the corresponding duration. The total MBR corresponds to the value obtained by expression (3) and it can be seen that about 30% of it is obtained in the PDS scenario. The MBR value was also compared with the regulated amount obtained by the TSO when applying the existing Postage Stamp Tariffs for Use of Networks. The MBR would only cover 10% of this regulated amount. This means that the STMP were very homogeneous along the system, that there were no significant congestion problems, except to some extent in the PDS scenario, that the transmission network was by that time well planned and was fairly impartial not compromising or distorting the dispatches from market mechanisms. Finally, if such a short term marginal based tariff term would exist, there would be a large revenue reconciliation problem, since other tariff terms would have to be set in order to recover the remaining 90% of regulated remuneration.

B. Case Study Using a 6 bus test System [2]

In Figure 2 it is represented the one line diagram of a small test system used by some research teams in the scope of expansion planning studies [1, 2]. The original system has 5 nodes, generators in nodes 1 and 3 and 6 branches. The original load (connected to nodes 1, 2, 3, 4 and 5) is larger than the installed capacity so that a new power station is going to be connected to node 6. This means that the expansion planning problem has to address two issues – to connect node 6 to the rest of the system and to cope with a load increase of 10% along the planning horizon. We admitted that the investment cost in branches was given by (24) where P is the capacity and L is the length.

$$IC_{branch} = (0.9 + 0.3xP).L\,10^6\,\text{Euro} \tag{24}$$

The possible branches to build were organized in three cases:

- CASE 1 - branches 2-6 and 4-6 with capacity of 100 MW and branch 5-6 with 78 MW. In each corridor it was possible to build as many branches as required;
- CASE 2 - branches 2-6 and 4-6 with capacity of 50 MW and branch 5-6 with 39 MW. In each corridor it was possible to build as many branches as required;
- CASE 3 - branches 2-6 and 4-6 with capacity of 25 MW and branch 5-6 with 19,5 MW. In each corridor it was possible to build as many branches as required;

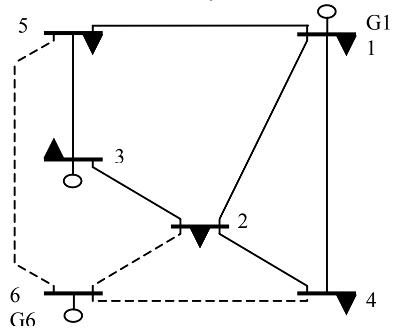

Fig. 2 – One line diagram of the 6 bus test system.

After running that expansion planning problem, we identified the most adequate plan for each of the above three cases. These three plans include building:

- CASE 1 – Generator G6, 2 branches 2-6, 2 branches 5-6 and 2 branches 4-6;
- CASE 2 – Generator G6, 5 branches 2-6, 3 branches 5-6 and 4 branches 4-6;
- CASE 3 – Generator G6, 8 branches 2-6, 8 branches 5-6 and 8 branches 4-6.

Table II includes the values of the nodal LTMP, the investment costs, IC, the operation costs, OC, the total costs, TC=IC+OC, the marginal based remuneration, MBR, obtained using the ideas in Section III.A but using LTMP and the percentage of total costs recovered by MBR.

Table II – Results obtained for the three tested cases.

	CASE 1	CASE 2	CASE 3
$LTMP_1$ (E/kWh)	9,23	9,56	9,23
$LTMP_2$ (E/kWh)	9,03	8,99	9,03
$LTMP_3$ (E/kWh)	8,00	8,00	8,00
$LTMP_4$ (E/kWh)	9,14	9,18	9,14
$LTMP_5$ (E/kWh)	9,92	10,54	9,92
$LTMP_6$ (E/kWh)	8,00	8,00	8,00
IC (10^6Euro)	6624,00	6561,00	7272,00
OC (10^6Euro)	3132,49	3286,31	3132,48
TC (10^6Euro)	9756,49	9847,31	10404,48
MBR (10^6Euro)	8181,45	9491,19	8174,18
% Recovery	83,86	96,38	78,56

As indicated in this Table, the MBR based on LTMP is able to recover large percentages of the total incurred costs. The variation of this percentage is mainly related with the different investment costs incurred in the three cases and also due to larger geographic dispersion of LTMP in CASE II that explains a larger MBR.

VI. CONCLUSIONS

In this paper we present the first version of an transmission network expansion planning model that inherently addresses the discrete nature of investments and allows evaluating the Long Term Marginal Prices as well as the related Marginal Based Remuneration of the transmission provider. The use of LTMP increases the percentage of recovered remuneration thus addressing the Revenue Reconciliation Problem usual when using Short Term Prices. This feature, together with the fairness and technical transparency of LTMP turn this kind of models very important in today power systems. The described model is being further developed to include a multi-period dynamic module, uncertainties related to load evolution eventually modeled by fuzzy set concepts and a criteria to measure the reliability of each plan so that new reports will be published in the near future.

VII. REFERENCES

[1] "Marginal Pricing of Transmission Services: A Comparative Analysis of Network Cost Allocation Methods", F. J. Rubio, I. Pérez-Arriaga, Power Engineering Review, November 1997.

[2] "Marginal Pricing of Transmission Services: An Analysis of Cost Recovery", I. J. Pérez-Arriaga, F. J. Rubio, J. F. Puerta, J. Arceluz, J. Marin, IEEE Trans. on Power Systems, Vol. 10, Nr. 1, February 1995.

[3] "Marginal Pricing and Supplement Cost Allocation in Transmission Open Access", H. Rudnick, R. Palma, J. Fernandez, IEEE Trans. on Power Systems, Vol. 10, Nr. 2, May 1995.

[4] "The Long Term Impact of Transmission Pricing", J. Maragon Lima, E. Oliveira, IEEE Trans. Power Systems, Vol. 13, Nr. 4, November 1998.

[5] "Allocation of Transmission Fixed Charges: An Overview", J. Maragon Lima, IEEE Trans. Power Systems, Vol. 11, Nr. 3, August 1996.

[6] Spot Pricing of Electricity, F. Schweppe, M. Caramanis, R. Tabors, R. Bohn, London, Kluwer Academic Publishers, 1988.

[7] Rivier, M., Pérez-Arriaga, I. J., "Computation And Decomposition of Spot Prices for Transmission Pricing", 11th Power Systems Computation Conference, PSCC'93, Avignon, France, August 1993.

[8] Rudnick, H., Palma, R., Lira, H., "Penalty Factor Calculations for Marginal Pricing of Transmission Systems in a Hydroelectrical System", Stockholm Power Tech, SPT'95, Stockholm, Sweden, June 1995, pp. 704-709.

[9] Saraiva, J. T., "Evaluation of the Impact of Load Uncertainties in Spot Prices Using Fuzzy Set Models", 13th Power Systems Computation Conference, PSCC'99, Trondheim, Norway, July 1999, pp. 265-271.

[10] Simulated Annealing and Boltzman Machines, E. Aarts, J. Korst, New York, John Wiley & Sons, 1990.

[11] Electric Utility Planning and Regulation, E. Khan, American Council for an Energy-Efficiency Economy, Washington DC, USA, 1988.

[12] Saraiva, J. T., Silva, J. P., Ponce de Leão., M. T., Magalhães, J. M., "Tariffs for Use of Networks" (in portuguese), available in http://www.erse.pt, July 2000.

[13] Silva, J. P., Saraiva, J. T., Ponce de Leão, M. T., "Use of Power Flow Based Embedded Methods To Set Tariffs For Use of Newtorks, A Case Study Using The Portuguese Transmission Company", IEEE Porto Power Tech Conference, PPT 2001, Porto, Portugal, September 2001.

[14] Saraiva, J. T., Silva, J. P., Ponce de Leão, M. T., "Evaluation of The Marginal Based Remuneration, A Case Study Using The Portuguese Transmission Network", IEEE Porto Power Tech Conference, PPT 2001, Porto, Portugal, September 2001.

VIII. BIOGRAPHIES

António Dias Braga was born in Seia, Portugal, in 1964. He received his licentiate and MSc degrees from Faculdade de Engenharia da Univ. do Porto (FEUP) in 1991 and 1997, in Electrical and Computers Engineering. In 1991 he joined the Polytechnic Institute of Guarda (IPG). He is currently a PhD student in Electrical and Computer Engineering at FEUP.

João Tomé Saraiva was born in Porto, Portugal in 1962. In 1985, 1993 and 2002 he got his degree, PhD and Agregado degrees in Electrical and Computer Engineering from Faculdade de Engenharia da Univ. do Porto (FEUP) where he is currently Professor and teaches graduate courses on market issues and EMS/DMS systems. In 1985 he joined INESC where he is research manager. He was head researcher or collaborated in several projects related with the development of DMS systems, quality in power systems in the scope of re-regulation and tariffs due for the use of transmission and distribution networks.