SOLVING THE REVENUE RECONCILIATION PROBLEM OF DISTRIBUTION NETWORK PROVIDERS USING LONG TERM MARGINAL PRICES

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Abstract – In this paper we describe an integrated methodology to compute Long Term Marginal Prices in distribution networks. Long Term Marginal Prices are considered the most interesting and economically sound way of allocating network costs to users. Additionally, they inherently deal with the Revenue Reconciliation Problem, as they generally do not require other large supplementary tariff terms. The proposed methodology uses Fuzzy Sets to model uncertainties in load forecasts and considers several criteria to guide the identification of solutions. At the end, there is a final decision-making step to select the most adequate expansion plan according to the preferences of the Decision Maker.

Keywords: Long Term Marginal Prices, Simulated Annealing, Electricity Markets, Regulatory Policies.

I. INTRODUCTION

The implementation of market mechanisms in the electricity industry aims at developing procedures to turn electricity closer to a commodity to be traded in open markets. The transformation of the classical vertically integrated electricity systems started by the introduction of competition in the generation subsector. This was achieved either with pool mechanisms – symmetrical or asymmetrical – or by admitting bilateral contracts – physical or financial. Current trends clearly show preference for mixed market structures integrating voluntary day-ahead markets, the possibility of establishing bilateral contracts and financial hedging mechanisms. The models adopted in Norway and Sweden, in Spain, in California and the recent changes in England and Wales are examples of such mixed structures.

Apart from the implementation of structures to organize the relations between generation and supply in competitive terms, the move to the market also had some other structural and economic impacts:

- in a first step vertical utilities were unbundled in several companies devoted to generation, transmission and distribution. Generation activities are subject to competition while transmission is provided in a natural monopoly basis requiring the adoption of regulatory policies;
- in a second step, the progressive reduction of the eligibility levels lead to the separation of distribution network activities from retailing ones. In a similar way to transmission, distribution network activities are provided in a natural monopoly basis subjected to regulatory policies;
- retailing became a competitive business bringing the market closer to end consumers. The separation of retailing from distribution became a key ingredient to provide equal access conditions to all consumers regardless of their size;
- from a technical point of view, electricity markets are quite more demanding than any other commodity market since electricity must comply with Kirchoff Laws and cannot be stored in large quantities. This is the main reason for the emergence of System Operators to coordinate the operation and to ensure the security of the system. In recent years, Independent System Operators and Transmission Providers are merging their activities leading to the appearance of Transmission System Operators – TSO;
- this process clearly showed the emergence of four groups of activities: generation, retailing, network (transmission and distribution) and regulation and control. The first two activities are developed in a competitive way, while the third is provided in a monopoly basis. This requires the adoption of regulatory schemes defined by regulatory agencies included in the fourth group.

Regulation is an activity aiming at establishing rules in an economic sector or inducing/forcing changes in the behavior of agents. This can be accomplished by setting prices of services, levels of revenue and investment, quality of service indices, and conditions of access. Apart from its general principles – transparency, efficiency, stability, consistency and fairness – tariff regulation must ensure the economic viability of regulated companies as well as protecting the clients of those services. In this scope, network companies are remunerated by tariffs for use of their networks [1]. A large number of methods have been described to allocate costs to network users. They differ on their basic conceptual grounds, on their simplicity of application and on their technical and economic robustness and efficiency. Among them, Marginal Prices are well known for the quality of the economic signals they can transmit despite having some drawbacks. Specifically, Short Term Marginal Prices – STMP - remunerate short term costs. This typically leads to a small income when compared to the regulated remuneration, namely because they are not able to recover longer term investment costs. This is why STMP based tariffs lead to a Revenue Reconciliation Problem [2, 3, 4]. This problem has to be solved by using, for instance, other tariff terms based in embedded approaches. If these supplementary terms are not adequately set, they can distort or mitigate the economic signals of STMP.

Long Term Marginal Prices - LTMP - reflect both short term operation and longer term investment costs and are particularly adequate if one tries to address in a global way the Revenue Reconciliation Problem. They are computed in the scope of long

term planning studies. These formulations are typically very complex due to the uncertainties in load forecasts, the combinatorial and the multi-criteria nature of the problem. However, given the quality of the inherent economic signals, it is important to develop new models to compute LTMP in a more realistic and effective way. Regarding transmission networks, references [5, 6] detail models using genetic algorithms and a dynamic programming approach to evaluate LTMP.

Given the current separation between retailing and distribution network activities, a new attention is directed to distribution networks. In this paper, we describe an integrated methodology to compute LTMP in the frame of a multi-criteria formulation that identifies efficient expansion plans of distribution networks. These efficient plans are selected using a Simulated Annealing algorithm. This metaheuristic is able to deal with the binary nature of several variables. The list of efficient plans is subjected to a Decision Making final step in order to select an expansion plan according to the preferences of the Decision Maker.

After this introductory section, Section II details several issues regarding regulation of network providers and cost allocation methods, Section III compares STMP and LTMP from a conceptual point of view referring their impacts in the collected remuneration, Section IV describes the model and the approach used to compute LTMP. Section V presents some results obtained using a case study based on a Portuguese distribution network and Section VI includes the main conclusions.

II. THE REGULATION AND REMUNERATION OF NETWORK PROVIDERS

A. Regulatory Schemes

The regulatory policies in network activities are crucial as they ultimately try to improve the performance of companies in terms of economic, technical and quality of service levels. These policies are also designed to ensure the economic viability of the regulated companies and to transmit adequate signals to induce more efficient policies. However, transmission and distribution companies are usually subject to different regulatory policies reflecting their distinct situations. Usually transmission companies are quite efficient, their investment demands in terms of the global investments in the industry is small as well as the share of their costs regarding the price of the final product. This justifies the adoption of CoS/RoR policies in several countries. On the contrary, the technical and economical performance of distribution companies is poorer. Their lower levels of automation require larger investments so that the share of distribution costs in the price of the final product is larger. This typically leads to incentive regulatory schemes either by price caps, revenue caps or benchmarking. Any of these regulatory schemes must be complemented by a quality of service regulation imposing minimum requirements as well as penalties and compensations to the clients if violated.

B. Tariffs for Use of Networks

Independently of the used regulatory scheme, network providers are remunerated by Tariffs For Use of Networks that reflect operation, maintenance and expansion costs. These tariffs are conceived according to some general principles as the ability to recover costs, the possibility of inducing the efficient use of networks, the promotion of efficient investments, the transmission of signals to select the most adequate connection point, the fairness in allocating costs to users, transparency, accountability and workability in terms of the ability to implement tariff systems in real sized networks.

The literature describes a large number of cost allocation methods that can be classified in three main groups:

- Embedded approaches – they basically correspond to average cost methods and several of them were originally conceived in the scope of wheeling transactions. They include methods not requiring power flow studies – as postage stamp, red path allocation – but also methods using results of power flow analysis as MW.mile, Modulus or Use, Zero CounterFlow and Dominant Flow [7]. They tend to be very simple to apply but they generally fail to reflect the technical operational conditions of the networks;
- Incremental Methods – they compare costs incurred with and without a specific transaction. The application of these methods can be complex and potentially unfair if a large number of transactions are present. In this case, and given the non-linearities of power systems, the order through which each transaction is treated becomes crucial. In fact, the adoption of different orderings can lead to different cost allocation profiles. The concept of Area of Influence present in the Chilean and Argentinean regulations is an example of an incremental approach;
- Marginal Methods – they evaluate marginal prices corresponding to the surplus of cost if the load or generation at a given node is increased of one unit. These prices can be defined by (1) assuming that Z is the cost function, Pl_k and ρ_k are the load and the marginal price at node k.

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

Marginal Prices typically display a geographic dispersion and can be evaluated using short term or long term formulations depending on the considered costs. They are very appealing both from technical and economical points of view but they also have some drawbacks. Given their relevance in this work, they will be discussed in detail in the next section.

III. SHORT/LONG TERM MARGINAL PRICES

The Short Term Marginal Price – STMP - of electricity [8, 9] can be defined as the variation of the cost function reflecting operation costs at an instant t in a node k if the load or generation at that node, given the operation state at instant t, increases of 1 unit. STMP are easily calculated as a sub-result of short term operation problems [10, 11]. They are also very volatile [12] since they depend on the load level, the generation policy, the reliability of components and the topology in operation. They usually display a strong geographic dispersion reflecting the presence of load and generation predominant areas, network congestion and active losses. The practice

indicates that network congestion has a very strong effect over STMP even leading to the economic separation of power systems in islands having very different and virtually independent price levels. In general, prices are higher in load areas when compared to prices in predominantly generation areas. Assuming that ρ_k is the STMP (\$/MWh) in node k at a given instant and accepting that loads pay and generators are paid the price at the node they are connected to, expression (2) gives an excess of remuneration per hour that can be used to partially remunerate network providers.

$$MR = \sum_{\text{nodes } k} \rho_k.(Pl_k - Pg_k) \text{ \$/h} \qquad (2)$$

If we suppose that the regulatory scheme defines a time discretization, then we can consider a number of scenarios sc along a year in which one wishes to evaluate the marginal based remuneration. In this case, the Short Term Marginal Price yearly based remuneration is given by (3). In this expression T_{sc} is the duration of the scenario sc.

$$MR = \sum_{\text{scenarios sc}} \sum_{\text{nodes } k} \rho_k.(Pl_{k,sc} - Pg_{k,sc}).T_{sc} \qquad (3)$$

MR typically corresponds to a reduced amount of the regulated remuneration of network providers. This is clearly due to the fact that STMP only remunerate operation costs included in the short term horizon. Two illustrative examples are:

- reference [3] indicates a percentage of 15% for the marginal based remuneration of Chilean transmission companies in terms of the regulated remuneration (although STMP in use in Chile only reflect the locational cost of losses not including transmission congestion, thus leading to a more reduced geographic dispersion);
- a recent study [13] using the 400, 220, 150 kV Portuguese transmission network and 15 generation/transmission scenarios publicly available indicated a value of only 10% for this percentage.

Apart from this reduced percentage, there is a perverse effect due to the fact that the geographic dispersion, and thus the marginal based remuneration, are increased as the operation of the system gets degraded. This ultimately means that a reduction on investments turns the system more congested so that MR increases. This stresses the fact that the adoption of a STMP tariff must be complemented by other terms to recover the whole regulated remuneration along with specified expansion investment plans and quality of service regulations.

The large Revenue Reconciliation Problem arising from the application of STMP can be addressed and eventually solved by using Long Term Marginal Prices – LTMP [6, 9, 14]. These can be defined as the variation of the cost function – now reflecting investment costs and expected operation costs over a planning horizon – subject to meet a forecast demand at a specified reliability level. In this scope, the LTMP at a given node reflects the variation of the cost and investment levels due a change in the presently forecast demand. If there were neither economies of scale nor normalization reflecting technical manufacturing conditions, network companies would be able to recover the complete regulated remuneration and the Revenue Reconciliation Problem wouldn't exist. This justifies the attention that must be directed to the development of workable models to evaluate LTMP.

LTMP must be evaluated in the scope of expansion planning problems for which the literature describes a number of models. Some of them approximate binary variables by continuous ones leading to continuous and differentiable formulations. In this case, the generic expression (1) still holds. The adoption of an approach of this type leads to a subsequent problem since the identified solution will not in general correspond to a technically feasible one due to normalization issues. Normalization modifies the level of investment required to implement a plan so that the previously computed LTMP will not be enough to recover the whole amount of costs.

The difference between the solution of continuous models and technically feasible solutions is the main reason to represent binary variables accurately. Discrete and combinatorial problems can be solved using Simulated Annealing since the concept of neighbourhood used in this meta-heuristic leads us to only consider feasible solutions. The use of a non continuous formulation also means that (1) does not hold any more. If we consider operational, reliability and investment costs [14] when solving the problem, LTMP will now be evaluated by (4). The evaluation of operation, reliability and investment costs is addressed in Section IV.

$$LTMP_k = \frac{\Delta CO}{\Delta Pl_k} + \frac{\Delta CR}{\Delta Pl_k} + \frac{\Delta CI}{\Delta Pl_k} \qquad (4)$$

In this expression, ΔCO, ΔCR and ΔCI represent the variations of operation, reliability and investment costs due to a change in load Pl_k. Given this definition, these prices are eventually more adequately called Long Term Incremental Prices rather than Marginal ones. The resulting expansion plans, apart from being completely financed by these prices, can also be interpreted as related to Economically Adapted Systems [5]. They constitute reference plans for the expansion of networks in order to cope with forecasted loads. The methodology to describe can also be useful to Regulatory Agencies since it offers tools to set reference expansion plans and the related tariffs for use of networks in an economically logical way.

IV. EVALUATION OF LONG TERM MARGINAL PRICES IN DISTRIBUTION NETWORKS

A. Multi-Objective Formulation

Long term marginal prices are calculated using an optimization tool that explicitly includes economic interactions between suppliers and loads at various locations while taking into account the power flows that result from the use of networks. This means that the adopted model explicitly considers economic and technical efficiency.

This approach includes in an integrated way several issues that are not accurately addressed in other existing tools. We considered long term investment, operation and reliability related costs (Energy Not Supplied), congestion constraints, and load uncertainties expressed by fuzzy models. This leads to the

following multiobjective mixed-integer formulation (5) to (12) involving binary variables related to the decisions to build facilities or not:

$$\min c_I = \sum_{i=1}^{p}\sum_{k=1}^{m} c_{ki}.\delta_{ki} \quad (5)$$

$$\min \tilde{c}_O = \sum_{i=1}^{p}\sum_{k=1}^{m} \tilde{p}_{ki}.\tilde{x}_{ki} \quad (6)$$

$$\min \tilde{c}_R = \sum_{i=1}^{p} \tilde{e}_i^t.\sum_{k=1}^{m} \tilde{x}_{ki}.FOR_k \quad (7)$$

$$\text{subj.} \quad \tilde{x}_i = A_i.\tilde{d}_i \qquad i=1...p \quad (8)$$

$$\left|\tilde{x}_{ki}\right| \le \gamma_{ki}.\bar{x}_k \qquad i=1..p,\ k=1..m \quad (9)$$

$$\left|\Delta\tilde{U}_{ji}\right| \le \Delta U_{max} \qquad i=1..p,\ j=1..n \quad (10)$$

$$\sum_{i=1}^{p}\delta_{ki} \le 1 \qquad k=1..m \quad (11)$$

$$\gamma_{ki} \ge \sum_{j\le i}\delta_{kj} \qquad k=1..m,\ i=1\ldots p \quad (12)$$

where:

- c_{ki}, $\tilde{p}_{ki}$ and $\tilde{e}_i$ - per unit investment, branch active losses and power not supplied costs;
- γ_{ki} - network configuration in period i including 1 or 0 for each branch k depending on its existence;
- δ_{ki} - 1 if one decides to build a facility k in period i ;
- p - total number of periods in the planning horizon;
- n and m - number of nodes and of branches;
- $\tilde{x}_i$ - vector of fuzzy branch flows in period i;
- $\bar{x}_k$ - power flow limit of branch k;
- $\tilde{x}_{ki}$ - power flow in branch k in period i;
- $\tilde{d}_i$ - vector of injected powers in period i;
- $\tilde{U}_{ji}$ - voltage magnitude in node j in period i;
- FOR_k - forced outage rate of branch k.

We assume that a list of m facilities is available. This list includes branches or substations that can be built or reinforced along the horizon. The problem aims at organizing elements of that list in plans. Each plan corresponds to a network configuration able to supply the required loads along time, to connect existing or forecasted dispersed generation and to meet several constraints. The model considers three criteria: investment costs (5), operational costs (6) and reliability costs (7). Investment costs are directly related to the list of facilities to build in period i. Operational and reliability costs emulate the cost of active losses and of energy not supplied. They are represented by fuzzy valued functions reflecting load uncertainties and are modelled by triangular fuzzy numbers. For a period i and for a list of available components, Energy Not Supplied, ENS, is evaluated using a simplified calculation that admits that all loads downstream a branch out of service are curtailed. Since we are dealing with radial networks, this corresponds to multiply the FOR of that branch by the power flow through it, when the system was intact. The summation of all these terms gives an estimate of the Energy Not Supplied.

Constraints (8) represent the branch flows computed for each period i using sensitivity coefficients A and nodal fuzzy injections $\tilde{d}$. Constraints (9) and (10) impose maximum limits on branch flows and on voltage drops. Constraints (11) ensure that a facility is built at most in one period and (12) is included to consider the temporary decommissioning of branches allowing its reentry in subsequent periods.

Multiyear investments integrated in the list of facilities should be seen both in terms of costs and of availability. Regarding costs incurred in previous periods, they should be referred to the final period using an appropriate rate. In what concerns availability, it is clear that such a facility will only be available at the final period.

In order to cope with uncertainties in injections – loads or dispersed generation – we used an AC Fuzzy Power Flow detailed in [15]. This turns the approach more flexible in the sense that it takes care of an infinite number of load/generation scenarios in an holistic way. In fact, we do not run a problem for each specific injection scenario since fuzzy models allow us to consider uncertainty within a single run. This is a most important feature since the presence of uncertainties is typically referred as a major difficulty in long term planning studies and a reason for heavy and time consuming computation.

B. Solution Approach and Computation of LTMP

The above problem was solved using a two step strategy. In the first place, a representative sample of non-dominated solutions is generated using a multiobjective heuristic approach [16]. In the second step, a decision-aid procedure helps the planner to select a plan while evaluating long term marginal prices in a nodal basis or average values in a regional basis.

STEP 1 – Generation Step

There are two strategies to identify non-dominated solutions:

- Weighting Method – it assigns weights to the different objective functions and combines all of them into a single objective function. It can be proved [16] that for each combination of strictly positive weights, the optimal solution of these partial problems corresponds to a non-dominated plan. This method is fully efficient only if the frontier of the solution space is convex;
- ε-Constraint Method – it consists of specifying bounds on all but one of the objective functions thus building a single objective problem. By varying the bounds imposed to the objective functions according to the specified ε, it is possible to obtain different non-dominated solutions. This approach is independent of the eventual non convexity of the non-dominated frontier.

This Step, although transformed into several optimization problems, still has a combinatorial nature. To cope with this fact in a realistic time a Simulated Annealing procedure was combined with the ε-Constraint Method to form a methodology to generate non dominated plans. To apply this search method the bounds for each objective function are specified in advance and the Simulated Annealing acceptance function is adapted to integrate the constraints related to those bounds. The

implementation iteratively applies the algorithm, using several modified acceptance functions, where each function reflects the limits chosen for the ε-constraint method. The output of this phase is a list of alternative plans covering the whole solution space.

STEP 2 – Decision Procedure

At the end of Step 1, a list of efficient plans evaluated by the attributes of the problem is provided. Investment Cost, Operation Cost (transmission losses) and Reliability Cost (Energy Not Supplied) are used to characterize each plan. This list can be more or less extended depending on the size of the parameter ε.

A plan is defined as a list of facilities to build in each period i. It is also characterized by the remuneration that can be recovered by the network company if using the LTMP computed for that plan and period. This remuneration also reflects technical constraints - congestion and quality of service – that are eventually on the limit. Finally, each plan is implicitly related to a certain level of tariffs for use of networks that allow recovering the associated costs.

The final decision process is out of the scope of this paper and the interested reader can find a detailed description of it in [17]. In brief words, it can be structured in two general ways:

- a selection rule can be adopted. As an example, one can build the ideal solution using the best value in each attribute over all solutions from Step 1. Afterwards, one computes the distance from each solution characterized by its attributes to the ideal adopting a selected metric;
- the solutions identified in Step 1 can be clustered leading to the identification of prototypes, also interpreted as macro-solutions. These macro-solutions are then presented to the decision maker that has the possibility of including his preferences and eventually make a zoom on some macro-solutions to get more insight on them.

C. Tariffs/Investment Plans/Quality of Service

One of the clearest evidences of the re-regulation process is the more direct interaction between economic and technical issues. In the distribution network activity this means that Quality of Service Regulations impose levels of Continuity, Quality of Wave and Commercial Quality requiring investments, namely in network expansion. This corresponds to an assurance given to consumers regarding a service provided in a monopoly basis. However, distribution network companies must recover their costs by adequately setting Tariffs for Use of Networks. If this interaction is broken, by artificially reducing tariffs, the consequence will be a reduction of Quality of Service to a level compatible with the recovered remuneration, or the bankruptcy of companies. Naturally each level of Quality of Service has a cost and, therefore, has an inherent and economically related level of Tariffs. In this sense, the above information – alternative plans, values of attributes and remunerations along the planning horizon – is valuable not only for network expansion planners but also to Regulatory Agencies. These Agencies have an integrated approach that can be used to:

- identify alternative plans with different costs and the corresponding tariff levels;
- analyse the sensitivity of those tariff levels to different quality of service requirements. This means that more or less relaxed voltage limit constraints can be considered at a time, in order to build the corresponding plans and tariff levels.

It is clear that Regulatory Agencies have to address in a more integrated way technical problems and the financial performance of companies in order not to break these ties. This approach can be viewed as a contribution in this direction.

V. CASE STUDY

In order to illustrate our methodology, we identified alternative expansion plans and the corresponding LTMP for a realistic distribution network based on a Portuguese network. The original system has 49 nodes, 68 possible branches and 3 supplying HV/MV substations. The planning exercise considered 3 periods and each plan is a set of 3 radial networks each one constituted by a set of branches and substations. Each alternative plan is also characterized by nodal prices that lead to a level of remuneration collected via marginal prices along the 3 planning periods. As an example, plan 42, considers building one more line in period 2 and reinforcing one substation and building 5 new lines in period 3.

Table I includes the values of the three attributes (investment costs, losses and reliability measured by the Energy Not Supplied, ENS) for some alternative plans.

Table I - Attributes for 6 efficient solutions.

Solution	Cost (10^5\$)	Losses (kW)	ENS (MWh)
42	247.76	642.44	3.53
75	242.98	543.00	3.50
79	320.76	437.76	2.71
89	209.64	612.00	3.50
190	303.19	424.43	2.67
194	298.01	444.41	3.10

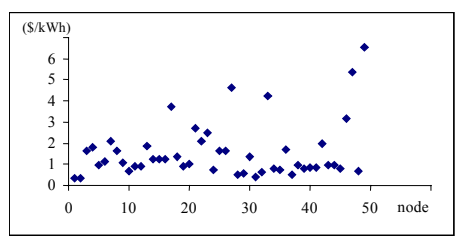

Fig. 1 – Nodal Marginal Prices obtained for plan 42 in the third period ($/kWh).

Taking the expansion plan 42 as an example, we present in Figure 1 the values of the long term marginal prices for period 3. Table II includes for period 3 – the period in which loads are higher – the values of the LTMP, the symmetric of the injection values and the contribution of each node for the global network remuneration according to expression (2). The sum of these contributions leads to 1078.4$/h in this period. Considering that each period has 8760 h during which the load is assumed constant, the global remuneration along the three periods is given by (13). These values were obtained using (3) where STMP were replaced with LTMP. It should be mentioned that a finer discrimination of load representation through time can be easily considered by enlarging the number of periods.

$$MR = MR_{p=1} + MR_{p=2} + MR_{p=3} =$$
$$= (742.1 + 1024.1 + 1078.4) x 8760 = 249.187 x 10^5 \$ \quad (13)$$

Table II – Partial remunerations obtained for the third period.

Node	LTMP $/kWh	-Pinj kW	MR $/h	Node	LTMP $/kWh	-Pinj kW	MR $/h
1	0.34	0.0	0.00	26	1.64	121.30	198.33
2	0.34	28.6	9.73	27	4.63	11.30	52.32
3	1.66	116.8	194.41	28	0.48	27.88	13.38
4	1.80	46.7	83.92	29	0.55	19.59	10.81
5	0.96	34.7	33.41	30	1.35	116.78	157.22
6	1.15	0.0	0.00	31	0.39	4.52	1.79
7	2.08	173.3	359.87	32	0.62	38.42	23.82
8	1.61	30.9	49.85	33	4.25	12.05	51.20
9	1.07	41.4	44.17	34	0.79	56.51	44.88
10	0.70	52.7	37.18	35	0.73	0.00	0.00
11	0.89	34.7	30.76	36	1.67	6.03	10.09
12	0.88	3.8	3.33	37	0.50	82.12	41.15
13	1.88	20.3	38.19	38	0.98	39.18	38.27
14	1.27	61.0	77.23	39	0.79	57.26	45.47
15	1.22	0.0	0.00	40	0.87	54.25	47.00
16	1.27	17.3	21.98	41	0.86	9.04	7.76
17	3.72	74.6	277.17	42	1.95	48.97	95.67
18	1.35	0.0	0.00	43	0.95	17.33	16.48
19	0.89	22.6	20.16	44	0.93	42.19	39.42
20	1.02	0.0	0.00	45	0.76	18.08	13.82
21	2.72	87.4	237.55	46	3.14	3.77	11.84
22	2.08	17.3	35.99	47	5.36	-134.86	-722.9
23	2.51	90.4	226.92	48	0.70	-122.05	-85.53
24	0.73	52.0	37.97	49	6.54	-134.86	-882.0
25	1.64	17.3	28.33				

For plan 42, the sum of investment, operational and reliability costs corresponds to (14). The fuzzy values of the operational and reliability costs present in formulation (5-12) were defuzzified by taking the centers of mass of the corresponding membership functions. These values reflect the set of facilities to be built according to plan 42 and the center of mass of operational and reliability costs.

$$Costs = \sum_{p=1}^{3} (c_{I,p} + c_{O,p} + c_{R,p}) =$$
$$= 247.7 x 10^5 + 29.5 x 10^3 + 162.2 x 10^3 = 249.617 x 10^5 \$ \quad (14)$$

Comparing the values in (13) and (14), we conclude that Long Term Marginal Prices, calculated using a realistic formulation of the expansion problem, were able to recover the costs incurred by the regulated company. The small difference between them is negligible and may be due to numerical approximations.

VI. CONCLUSIONS

In this paper we presented an approach to compute Long Term Marginal Prices of distribution networks used to set tariffs for their use. The formulation represents the long term expansion planning problem in an accurate way using binary variables to represent investment decisions and fuzzy concepts to take into account load and dispersed generation uncertainties. The model considers three criteria thus leading to a decision problem. In a first phase, the solution approach uses the ε-constrained method combined with Simulated Annealing. The results of this phase are presented to the Decision Maker in the scope of a Decision process. Long Term Marginal Prices display very good properties in terms of their stability, fairness and ability to recover regulated costs to a larger extent. Given the separation of retailing from distribution network companies, this kind of approach is highly valuable both from the point of view of clients (in reducing tariff volatility and allocating costs more transparently and efficiently) and of regulated companies (in solving the revenue reconciliation problem and turning the income stream more stable and predictable).

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