LONG TERM COST ALLOCATION METHODOLOGY FOR DISTRIBUTION NETWORKS WITH DISTRIBUTED GENERATION

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Abstract – This paper proposes a novel access pricing framework to remunerate investment costs of distribution networks based on Long Term Prices (LTP) taking into account the avoided costs produced by the distributed generation (DG). The proposed methodology uses a fuzzy multicriteria distribution planning algorithm based on simulated annealing metaheuristic in order to obtain efficient expansion plans regarding the impact of distributed sources. Avoided investment costs are computed for several robustness indexes and allocated among consumers and generators by means of a modified roll-in-embedded cost allocation method. The proposed cost allocation approach is simple to implement using efficient plans and does not require high computer performance. The model has been successfully applied and results were discussed from a distribution test system.

Keywords: distributed generation, embedded generation, dispersed generation, cost allocation, distribution pricing, access pricing, regulation.

1 INTRODUCTION

Electricity markets have been established based on the statement of open access and nondiscriminatory use of transmission and distribution (T&D) infrastructure. However, T&D business remains as a monopoly and economic regulation is required in order 1) to hold price access near to marginal cost and 2) to provide full-powered incentives to minimize total costs [1]. It is not easy to fulfill with both objectives simultaneously. On the one hand, cost-of-service regulation (CoS) assures the recovery of all costs but no more. So, the profit of monopolist is recognized by the regulator by way of a reasonable rate of return of invested capital and CoS regulation is able to hold access prices down to long term costs but takes away all incentive to minimize cost. On the other hand, performance based ratemaking regulation (PBR), as price-cap or revenue-cap regulation, sets a cap through some formula that takes into account inflation and performance. Thus, with an access price cap, monopolist has the incentive to minimize cost and to increase profits. However, access price must always be higher than long term costs in order to avoid monopolist failure.

The tendency into ongoing deregulation process is to implement incentive regulation into T&D business. Now, the challenge is to develop an adequate access pricing framework to fairly allocate all costs and send correct economic signals to the utilities in order to obtain just access prices and to provide cost minimization incentives.

Literature describes many methodologies to deal with cost allocation problem of transmission services and certain maturity has been obtained in this area [2-5]. However, this is not true in the case of distribution services. A lack of information is observed about the investment cost allocation methodologies applied to distribution systems under incentive regulation. Also, distributed generation (DG) has faced a heavy growth in the recent years and a fundamental issue is how to assign investment (expansion) costs among electricity retailers and distributed generation utilities.

The basic question relates with whether DG investors must pay by the use of the network or receive any compensation due to the avoided or deferral investments produced by their placement into the network. This question must be clearly answered under the scope of distribution planning process taking into account the impact of distributed power.

In this sense, in order to send efficient economical signals, different cost allocation methodologies, using long term marginal pricing (LTMP) approaches, have been proposed in transmission [7-8] and distribution systems [9-10]. Generally, these frameworks may be used under PBR regulation as tariffs of use the network setting a price-cap to the network provider. This scheme becomes convenient in a market scenario when the network provider has a role of a facilitator of competition [6]. After, the network provider drives his own planning process with full-powered incentives to minimize investment (C_I), operational (C_O) and reliability costs (C_R) satisfying the power quality requirements imposed by the regulatory board. However, these long term marginal prices must be computed by the regulatory agency as a product of a long term network expansion planning with hard computational efforts [10-11].

One way to obtain marginal investment prices is through the Lagrange multipliers (1) associated to the nodal constraints in an optimal investment problem [9].

$$LTMP_k = \frac{\partial (C_I + C_O + C_R)}{\partial P_k} \tag{1}$$

Alternatively, an approximation of long term marginal prices may be assessed using an incremental analysis [10-12]. To do this, it is necessary to run the expansion-planning algorithm for all nodes of the system in order to measure the variations of investment costs respect to an increment in an each nodal injection (2):

$$LTMP_k = \frac{\Delta C_I}{\Delta P_k} + \frac{\Delta C_O}{\Delta P_k} + \frac{\Delta C_R}{\Delta P_k} \tag{2}$$

As seen in expressions (1) and (2), both frameworks are based in an *ex-ante* evaluation of marginal operational (losses) and marginal reliability costs (power not supplied) to be assigned among the future power injections forecasted by the regulatory planner.

In our opinion, actual market forces and present day technology make necessary and possible a real-time evaluation of the power losses and reliability costs into distribution networks. Therefore, these costs could be adequately allocated among all market agents using either *ex-post* cost allocation methodologies widely discussed in the literature [13-15]. Short term access pricing is out of scope of this paper, however could be reviewed in detail in [16].

This paper proposes an alternative access pricing framework to remunerate investment costs of distribution networks based on Long Term Prices (LTP) taking into account the avoided costs produced by the distributed generation resources.

The proposed methodology uses a *fuzzy multicriteria distribution planning algorithm* [17] based on simulated annealing metaheuristic in order to obtain efficient expansion plans regarding or not the influence of distributed sources. Avoided investment costs are computed for different degrees of confidence using the concept of robustness [17] and resultant avoided costs are allocated among consumers and generators by means of a modified *roll-in-embedded* cost allocation methodology based on traditional postage stamp procedure [3].

The proposed approach is simple to implement and does not require high computer performance as reported by long term marginal approaches. The model has been successfully applied and results were discussed from a distribution test system.

2 PROPOSED METHODOLOGY

2.1 Fuzzy Multicriteria Distribution Network Planning

Distribution network planning is assessed 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. In this paper we present the general formulation and resolution strategy. Detailed information can be found in [17].

A. Formulation

This approach includes in an integrated way several issues that are not accurately addressed in other existing tools. We consider long-term investment, operation, and reliability-related costs (power not supplied), congestion constraints, robustness of efficient plans and load uncertainties expressed by fuzzy models.

This leads to the following multiobjective mixed-integer formulation (3) to (11) concerning binary variables related to the decisions to build facilities or not:

$$\min c_I = \sum_{i=1}^{p}\sum_{k=1}^{m} c_{ki}\,\delta_{ki} \qquad \text{[INVESTMENT COST]} \quad (3)$$

$$\min c_O = \sum_{i=1}^{p}\sum_{k=1}^{m} l_{ki}\,x_{ki} \qquad \text{[POWER LOSSES]} \quad (4)$$

$$\min c_R = \sum_{i=1}^{p} e_i \sum_{k=1}^{m} FOR_k\,x_{ki} \qquad \text{[POWER NOT SUPPLIED]} \quad (5)$$

$$\max\ \beta_{PLAN} = \min_{c}\{\beta_c\} \qquad \text{[PLAN ROBUSTNESS]} \quad (6)$$

subj.

$$\mathrm{x}_i = \mathrm{A}_i\,\mathrm{P}_i = \mathrm{A}_i(\mathrm{P}_{Gi} - \mathrm{P}_{Di}) \quad i = 1 \ldots p \quad \text{[NETWORK EQS]} \quad (7)$$

$$|x_{ki}| \le \xi_{ki}\,\bar{x}_k \quad i = 1 \ldots p;\ k = 1 \ldots m \quad \text{[BRANCH FLOW LIMITS]} \quad (8)$$

$$|\Delta U_{ji}| \le \Delta U_{max} \quad i = 1 \ldots p;\ j = 1 \ldots n \quad \text{[VOLTAGE LIMITS]} \quad (9)$$

$$\xi_{ki} \ge \sum_{j\le i}^{p} \delta_{kj} \quad k = 1 \ldots m;\ i = 1 \ldots p \quad \text{[FACILITY OVERLAPPING]} \quad (10)$$

$$\sum_{i=1}^{p} \delta_{ki} \le 1 \quad k = 1 \ldots m \quad \text{[FACILITY OVERLAPPING]} \quad (11)$$

where all power flows and voltages are fuzzy sets, and

c_{ki}	investment cost of branch k in period i ($)
l_{ki}	branch active losses cost in period i ($/kWh)
e_i	power not supplied cost in period i ($/kWh);
ξ_i	network configuration in period i;
p	total number of periods in the planning horizon;
n	number of nodes
m	number of branches;
$\mathbf{x}_i$	vector of fuzzy branch flows in period (kW);
$\mathbf{A}_i$	Sensitivity matrix
x_k	power-flow limit of branch (kW);
x_{ki}	power flow in branch k in period i (kW);
$\mathbf{P}_i$	vector of injected powers in period i (kW);
$\mathbf{P}_{Gi}$	vector of injected powers by DG in period i(kW)
$\mathbf{P}_{Di}$	vector of injected powers by loads in period i(kW)
P_{ij}	injected powers in node j in period i (kW);
P_{Gij}	injected powers by DG in node j in period i (kW);
P_{Dij}	injected powers by loads in node j in period i (kW);
U_{ji}	voltage magnitude in node j in period i (kV);
FOR_k	forced outage rate of branch k (hr/year).
β	robustness.

The model addresses a network with n nodes and m possible branches, in a multi-period study with p periods. Decision variables δ_{ki} indicate if a branch k could be constructed in period i. Substations are represented by artificial branches to an auxiliary node. If branch k exists in period i (ξ_{ki} = 1) then it has a fuzzy flow x_{ki}. Each node j has coupled a voltage drop of ΔU_{ji}. In each period i, the fuzzy injection (loads or distributed generation) P_{ij} is known for each node j.

Sensitivity matrix $\mathbf{A}_i$ describes the network in each period i, relating the vector of fuzzy flows $\mathbf{x}_i$ with the fuzzy injections $\mathbf{P}_i$ (7). Branch limits (8) are considered, as well as maximum voltage drop (9). Constraints (10) ensure that a facility is built at most in one period and (11) is included to consider the temporary decommissioning of branches allowing its reentry in subsequent periods. Nonnegative and radiallity constraints are not represented.

The model considers four criteria: investment costs (3), operational costs (4), reliability costs (5) and robustness (6).

Investment costs are directly related to the list of facilities to build in each period. Operational and reliability costs emulate the cost of active losses and of power not supplied. They are represented by fuzzy-valued functions reflecting load uncertainties and are modeled by fuzzy numbers. 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 manage uncertainties in power injections —loads or distributed generation— we used an AC fuzzy power flow tool. This turns the approach to be more flexible in the sense that it takes care of an infinite number of load/generation scenarios in a 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 an important characteristic since the presence of uncertainties is typically referred to as a major difficulty in long-term planning studies and a reason for heavy and time-consuming computation.

Fuzzy inequality constraints (7) and (8) require a special treatment. The plan *robustness* or *confidence* is measured by a robustness index β, and defined as follows. A given plan is robust regarding a specific constraint if the constraint holds true for every possible value of the uncertain variables and constants. In that case β is equal to 1. On the other hand, if some instances of those quantities lead to violation of the constraint β equals the maximum possibility value for which the constraint is violated. Therefore, we have a robustness index β_c for each fuzzy inequality constraint c. A global index β_{PLAN} is then defined for the plan and included in as objective function (6). The value of β_{PLAN} concentrates the fuzziness of data, allowing the planner to consider plans that have a possibility $1-\beta_{\mathrm{PLAN}}$ of not being feasible. Then, the robustness concept is related to the *risk* or *confidence* of resultant plans.

B. Solution Approach

The solution of the proposed above multicriteria problem identifies efficient expansion plans of distribution networks. These efficient plans are selected using a simulated annealing algorithm [17]. This metaheuristic is able to deal with the binary nature of several variables. A list of efficient plans is subjected to a decision making in order to select an expansion plan according to the preferences of the decision maker. A two-step strategy is applied in order to get a final solution. The first step, a representative sample of nondominated solutions is generated using a multiobjective heuristic approach [17]. In the second step, a decision-aid procedure helps the planner to select a plan.

Step 1—Generation step: There are two strategies to identify nondominated solutions.

• Weighting Method — it assigns weights to the different objective functions and combines all of them into a single objective function.

• Constraint Method — it consists of specifying bounds on all but one of the objective functions thus building a single objective problem..

Step 2 — Decision Procedure: At the end of step 1, a list of efficient plans evaluated by the attributes of the problem is presented. Investment Cost, Operation Cost (distribution losses), reliability cost (power not supplied) and robustness are used to characterize each plan. At last, in order to determine the avoided or formed investment costs associated to plans with or without distributed generation only plans with the same robustness degree must be compared.

2.2 Cost Allocation Strategy

The multicriteria planning problem stated in section 2.1 must be run twice in order to apply the proposed investment allocation cost strategy. Firstly, the algorithm is run to find a list of non-dominated solutions or plans *disregarding* the effect of distributed generation. For each solution or plan we are able to compute the investment levelized cost or the *Annual Fixed Charge Rate* (AFCR_i) for each period i of the plan [3],[12]:

$$AFCR_i = CRF_i \cdot C_{Ii} = \frac{r_i(1+r_i)^t}{(1+r_i)^t - 1}\sum_{k=1}^{m} c_{ki}\,\delta_k \tag{12}$$

where *CRF* is the *Capital Recovery Factor*, t is the equipment lifetime and r_i is the adequate discount rate recognized by the regulatory agency for the distribution the utility in period i.

Finally, the algorithm is run once again in order to obtain a list of non-dominated solutions or plans *considering* the effect of distributed generation. For each solution or plan we compute the investment levelized cost taking into account the effect of distributed generation $\mathrm{AFCR}^{\mathrm{DG}}$:

$$AFCR_i^{DG} = CRF_i \cdot C_{Ii}^{DG} = \frac{r_i(1+r_i)^t}{(1+r_i)^t - 1}\sum_{i=1}^{p}\sum_{k=1}^{m} c_{ki}\,\delta_{ki}^{DG} \tag{13}$$

If we compare two plans —with and without distributed generation— at the same degree of robustness β we can define for each period i an *Annual Avoided Charge Rate* (AACR) as follows:

$$AACR_i(\beta) = AFCR_i(\beta) - AFCR_i^{DG}(\beta) \tag{14}$$

The introduction of this parameter is our modest contribution to evaluate the impact of distributed generators in the planning process and it let us to measure the annual savings (if AACR>0) or additional charges (if AACR<0) introduced by the connection of distributed sources to the grid at given level of confidence or robustness in the planning process. Under the proposed approach, if the connection of distributed sources generates avoided investments, the DG utilities must be rewarded and they must not be charged by the use of the network. On the contrary, if the connection of DG units does not avoid investments, then DG utility must to be charged due to cost increase. Consumers are always charged by the use of the network independently of the existence or not of distributed generation.

Using a traditional roll-in-embedded methodology as *postage stamp* [3] we are able to compute Long Term Prices (LTP) applied to consumers for each period i and robustness degree β as follows:

$$LTP_i\ (\beta) = \frac{AFCR_i(\beta)}{AEED_i} \tag{15}$$

where $AEED_i$ is the annual expected energy demanded (in kWh) to be consumed by all loads in period i. This parameter may be easily estimated from the planner data:

$$AEED_i = 8760 \cdot \sum_{j=1}^{n} P_{Dji} \tag{16}$$

where P_{Dji} is associated with a maximum daily demand forecasted by the planner for each consumer in period i. As indicated above, this parameter is a fuzzy set and therefore must to be defuzzified by means of the center of mass of each membership function. We observe that LTPs applied to loads are always positive and in consequence all consumers have to pay by the use of network.

Long Term Prices applied to distributed generators could be computed as the quotient of the AACR value and the annual expected energy injected to the network by generators in period i.

$$LTP_{ji}^{DG}(\beta) = \frac{AACR_i(\beta)}{AEEG_i} = \frac{AACR_i(\beta)}{8760\sum_{j=1}^{n} P_{Gji}} \tag{17}$$

where P_{Gji} is associated with a maximum daily power injected by each generator in period i. It is important to point out that LTPs applied to generators may be positive or negative. If they are positive DG utility receive a reward or incentive due to avoided investments. Conversely, if LTPs are negative, they have to pay by the use of network.

It is important to refer that economical signals provided to generators by proposed LTPs are similar to those proposed by marginal approaches in the sense that penalize or reward due to the network placement of DG. Additionally, the methodology is very simple to implement though a specified distribution network plan.

However, as the proposed methodology works with aggregated generation, it is not able to access the impact of individual generators, regarding the avoided investments, as marginal approaches are capable to do. To overcome this drawback another cost allocation strategies may be applied —for instance, by the use of proportional sharing procedures [14]— using the proposed concept of avoided costs from efficient planning processes considering the risk or confidence of solutions.

3 CASE STUDY

3.1 Network characteristics

In order to illustrate proposed methodology, we identified alternative expansion plans and the corresponding LTP for a realistic distribution network based on a Portuguese network shown in Figure 1. The original system has 51 nodes, 75 possible branches, and three supplying 15kV substations. Planning data can be found in [17] or requested to the authors.

The planning exercise considered three periods and each plan is a set of three radial networks, each one constituted by a set of branches and substations.

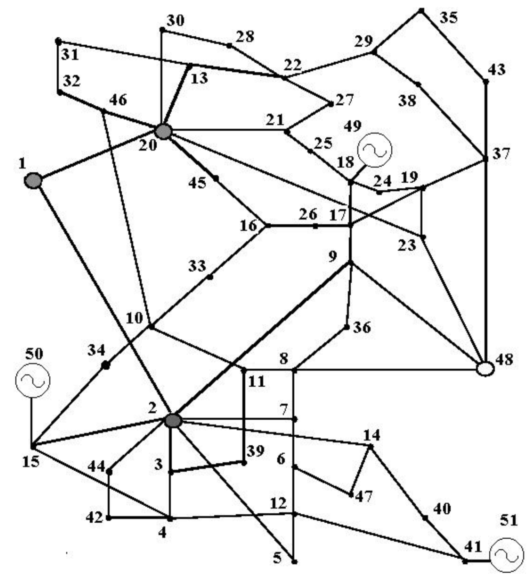

Figure 1: Test network

Three possible substations, two existing; S1 connected to node 2 (rated capacity 36MVA) and S2 to node 20 (rated capacity 22.5MVA), and another possible one to be constructed if necessary (rated capacity 7.5MVA) were included.

The case study also includes three independent generation units connected to the network: 2 mini-hydro plants, with regulation capacity are connected to nodes 18 and 15 respectively with 5.25 MW and 4.65 MW rated power and another one having 4.65 MW of rated power without that capacity of regulation is connected to node 41.

Table 1 and Figure 2 show the trapezoidal fuzzy sets associated to each distributed generator in each period. Note that in period 1 does not exist distributed generation.

Node	Period 1 (kW)				Period 2 (kW)				Period 3 (kW)			
	a	*b*	*c*	*d*	*a*	*b*	*c*	*d*	*a*	*b*	*c*	*d*
15	0	0	0	0	416	3793	4651	5118	935.3	3793	4651	5118
18	0	0	0	0	0	0	0	0	3377	4209	5248	5768
41	0	0	0	0	0	0	0	0	3715	4651	4651	5118

Table 1: Fuzzy distributed generation injections.

Annual expected energy (AEEG) to be injected by distributed generators to the network in periods 2 and 3 are 37.0GWh and 119.9GWh respectively. Period 1 does not have distributed generation injections.

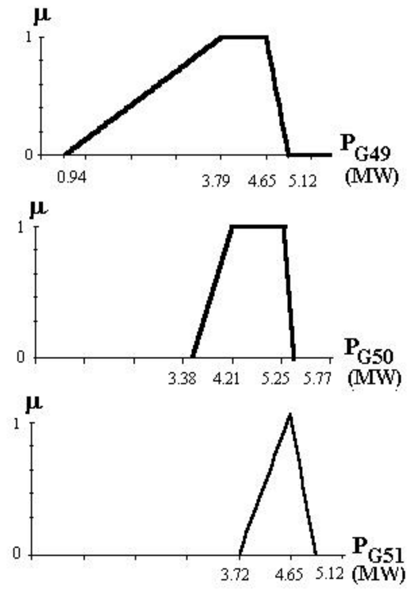

Figure 2: Fuzzy distributed generation injections.

Loads are represented by trapezoidal possibility distributions where μ is a membership degree between 0 (low possibility) and 1 (high possibility). Annual expected energy (AEED) to be consumed in each period is 266.7GWh, 458.5GWh and 545.7GWh respectively.

3.2 Results of Planning Process

A. Efficient plans without distributed generation

The multicriteria planning problem stated in section 2.1 is applied in the test network disregarding the effect of distributed generation.

Firstly, by means of the Simulated Annealing algorithm we are able to identify 104 efficient solutions or plans. Using the weighting and constraint method we generate a set of 32 non-dominated efficient plans.

Finally, from non-dominated solution list a final selection is built including only plans with higher robustness and lower investment cost. Table 2 presents 3 non-dominated solutions (Plan 1, 28 and 36) with three degrees of robustness: 1.00, 0.84 and 0.79.

Plan	β	C_I	Losses (kW)			PNS (MW)		
		(10^6 \$)	min	cntr.	max	min	cntr.	max
1	1.00	282.0	331	515	716	1.1	3.8	4.5
28	0.84	366.0	354	560	763	2.3	2.9	3.4
36	0.79	369.0	400	596	832	2	2.5	2.9

Table 2: Efficient plans disregarding distributed generation.

The solutions presented are evaluated by two crisp attributes, (investment cost and robustness) and fuzzy attributes (losses and non supplied power, PNS). The fuzzy attributes are represented by a trapezoidal member ship function, including the center of mass of the fuzzy set or centroid, maximum and minimum values.

B. Efficient plans including distributed generation

Simulated Annealing algorithm identifies 201 efficient solutions or plans including the effect of distributed generators connected to nodes 49, 50 and 51.

Using the weighting and constraint method a set of 49 non-dominated efficient plans is generated. A final selection is made including only plans with higher robustness and lower investment cost. Table 3 presents 3 non-dominated solutions (Plan 42, 172 and 80) with three degrees of robustness: 1.00, 0.84 and 0.79.

Plan	β	C_I	Losses (kW)			PNS (MW)		
		(10^6 \$)	min	cntr.	max	min	cntr.	max
42	1.00	248.0	424	644	972	2.7	3.5	4.4
172	0.84	301.0	298	456	700	2	2.7	3.4
80	0.79	303.0	388	551	803	1.3	1.9	2.2

Table 3: Efficient plans considering distributed generation.

3.3 Cost Allocation

For each period, the Annual Fixed Charge Rate is computed using the expression (12) where the discount rate was specified by regulator in 9.75% per year and the lifetime of the equipment was set in 35 years for all periods. Table 4 shows AFCR results for each efficient plan and each period.

Plan	β	C_I (10^6 \$)			AFCR (10^6 \$/year)		
		p=1	p=2	p=3	p=1	p=2	p=3
1	1.00	137.8	237.0	282.0	13.6	23.4	27.8
28	0.84	178.9	307.5	366.0	17.7	30.3	36.1
36	0.79	180.3	310.1	369.0	17.8	30.6	36.4

Table 4: Annual Fixed Charge Rate for each efficient plan

The AFCR considering the effect of distributed generators is computed using equation (13) with the same discount rate and lifetime period established above. Table 5 shows the $AFCR^{DG}$ results for each efficient plan and each period.

Plan	β	C_I^{DG} (10^6 \$)			$AFCR^{DG}$ (10^6 \$/year)		
		p=1	p=2	p=3	p=1	p=2	p=3
42	1	137.8	229.2	248.0	13.6	22.6	24.5
172	0.84	178.9	293.3	301.0	17.7	28.9	29.7
80	0.79	180.3	290.1	303.0	17.8	28.6	29.9

Table 5: $AFCR^{DG}$ for each efficient plan

By means of equation (15) we are able to compute the Long Term Prices (in cents\$/kWh) to be applied to all consumers for each plan and each period at same level of confidence or robustness. Table 6 illustrates the resultants LTPs.

β	AFCR(10^6\$/year)			AEED (GWh)			LTP (cts\$/kWh)		
	p=1	p=2	p=3	p=1	p=2	p=3	p=1	p=2	p=3
1.00	13.6	23.4	27.8	266.7	458.6	545.8	5.10	5.10	5.10
0.84	17.7	30.3	36.1	266.7	458.6	545.8	6.62	6.62	6.62
0.79	17.8	30.6	36.4	266.7	458.6	545.8	6.67	6.67	6.67

Table 6: Long Term Prices applied to consumers

We observe that in each plan the price is the same for all periods. This means that the tariffs of use of the network applied to consumers do not change due to the inclusion of distributed generators. Other remarkable fact is that prices are higher with lower confidence levels. At this point we could compute the Annual Avoided Fixed Rate value defined in expression (14) and the Long Term Prices applied to generators. Table 7 shows these results.

β	AACR(10^6\$/year)			AEEG (GWh)			LTP^{DG}(cts\$/kWh)		
	p=1	p=2	p=3	p=1	p=2	p=3	p=1	p=2	p=3
1.00	0.0	0.8	3.4	0.0	37.0	119.9	-	2.06	2.80
0.84	0.0	1.4	6.4	0.0	37.0	119.9	-	3.81	5.35
0.79	0.0	2.0	6.5	0.0	37.0	119.9	-	5.33	5.43

Table 7: AACR and Long Term Prices applied to generators

This exercise demonstrates that the distributed generation connected to the distribution network is capable to avoid or deferral investments in the network. For instance, in this case the penetration level of distributed generation in third period is close to 22% and the avoided investments varies from 12% for β=1 (high confidence level) and 17% for β=.79 (medium confidence level). We can see in Table 7 that LTPs calculated using equation (17) are positive —this mean that DG utilities must be compensated by avoided investments— and differently at each period and penetration level of distributed resources. As expected, we observe that less confidence levels derive in higher prices to be applied in order to ensure the revenue reconciliation of investment costs. Additionally, as DG penetration rises from period 2 to period 3, it is verified that the avoided costs and LTP^{DG} were also increased in all robustness levels.

Results show that the proposed cost allocation methodology could be applied as mechanism to remunerate and to incentive the development of distributed generation resources. In an aggregate o global way, the effects of tariff setting procedure is similar than marginal approaches in the sense that reward by avoided investments and penalize due to the increase of costs. However, it requires a multicriteria distribution planning platform including the evaluation of risk or confidence parameters.

4 CONCLUSIONS

The presented access pricing framework to remunerate investment costs of distribution networks is based on the computation of Long Term Prices (LTP). Proposed methodology uses a fuzzy multicriteria distribution planning algorithm in order to obtain efficient expansion plans regarding or not the influence of distributed sources. Avoided investment costs were computed for several robustness indexes and allocated among consumers and generators. Results demonstrate that distributed generation is capable to avoid or deferral investments in the network. The proposed cost allocation approach is simple to implement using efficient plans and does not require high computer performance. The methodology has been successfully applied and results were discussed from a distribution test system

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