Investment Decisions in Distribution Networks Under Uncertainty With Distributed Generation—Part II: Implementation and Results

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***Abstract*—This second part of a two-part paper presents the implementation and simulations of a risk-based optimization approach for distribution expansion planning with distributed generation (DG), as described in Part I. The proposed approach is first applied to a test system in order to test convergence of the optimization algorithm and then comparing its numerical results with the ones from the exhaustive method. Later, the expansion planning of a typical Latin American distribution network is assessed and analyzed. For this, two expansion optimizations are performed: one, taking into account traditional expansion alternatives (without DG) and, the other, considering DG as flexible expansion options. Finally, the computational effort is analyzed. Results show that the greatest contribution of DG lies in the flexibility it gives to expansion planning, mainly by deferring network reinforcements.**

***Index Terms*—Distributed generation, distribution planning, EPSO, expansion decisions, real options, risk analysis.**

NOMENCLATURE

Readers are referred to the nomenclature presented in Part I of the paper. New mathematical symbols used in this second part are defined within the text where necessary.

I. INTRODUCTION

THE application of performance-based regulations (PBR) and tariff schemes of the price-cap type, as is the case in Latin American, raises the need to develop approaches that allow reviewing short-term expansion investments from the point of view of an utility and which take into account the uncertainties of the main parameters. This work develops a comprehensive approach for optimization and risk analysis to support short-term investment decisions for a current distribution network, framed within long-term expansion planning, with the purpose of achieving an efficient synergy between returns and risk of expansion investments.

The expansion planning is formulated as a multistage problem, under normal and emergency operational conditions, using a mixed integer nonlinear mathematical model, solved by a heuristic method, namely evolutionary particle swarm optimization (EPSO). In addition, three main fossil-fuel technologies of distributed generation (DG) are considered to temporarily defer large network investments. The investment deferral benefit is assessed through a real option valuation. The type of DG technology to be installed, its location, size, operation, and timing, are all optimized.

In order to assess expansion investments, a return-per-risk index (RRI) that measures risk-adjusted returns is proposed. It is computed using the discounted cash flow method by means of Monte Carlo simulations. This RRI aims to normalize the expected returns per unit of risk in order to properly compare investment alternatives.

In this paper, the implementation of the risk-based optimization approach and its numerical results are presented, as described in the first part of this two-part paper [1]. Regarding the implementation, Section II explains the technical and cost issues; namely the evaluation of energy losses, voltage levels and power flows in lines and transformers under normal conditions, the assessment of reliability under emergency conditions, and the impact on protection systems by the installation of DG are described. The implementation of the comprehensive approach is also explained, as well as the application of EPSO and the procedure used for real option valuation (ROV). As for the results, Section III provides information on the robustness and optimality of the proposed optimization algorithm by comparing this risk-based optimization approach with the exhaustive method. Then, the application of the proposed approach for the expansion planning of a distribution network typical of Latin America is discussed. Moreover, a sensitivity analysis and the impact on expansion plans of installing a new big load are shown. At last, computing times associated with the results are shown. Finally, Section IV presents the conclusions of this work, emphasizing the "added value of DG" to the expansion distribution planning.

II. IMPLEMENTATION OF THE PROPOSED APPROACH

According to the methodological bases presented in the first part of this paper [1], the mathematical formulation of the expansion problem is briefly described by (1)–(5). This problem is governed by the stochastic processes for modeling uncertainty in demand growth (Dp) and the wholesale electricity price (Ep), through the performing of "M" Monte Carlo simulations over a given planning horizon "T" (1). Power demand is represented by the use of discrete load steps for each year (peak, medium and minimum load; as is shown in Fig. 1), changing with growing demand in terms of $Dp_{i,t}$:

$$\sum_{i=1}^{M}\sum_{t=1}^{T}\begin{cases} Dp_{i,t} = Dp_{i,t-1} + \Delta Dp_{i,t} \\ Ep_{i,t} = Ep_{i,t-1} + \Delta Ep_{i,t}. \end{cases} \tag{1}$$

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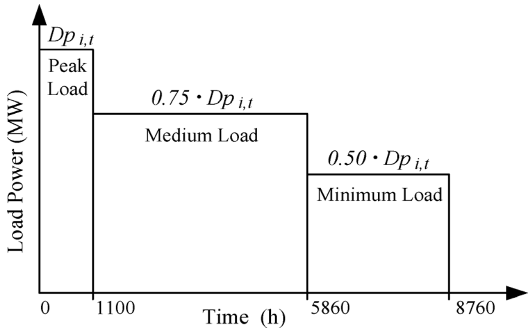

Fig. 1. Load duration curve.

The proposed risk-based optimization approach for supporting expansion investment decisions consists, essentially, in re-evaluating and re-formulating the expansion alternatives in order to maximize the RRI (2), i.e., maximize the expected return on the investment alternatives ($E[\mathrm{NPV}_{\mathrm{simulated}}]$) per unit of risk ($\sigma[\mathrm{NPV}_{\mathrm{simulated}}]$) (3), where the NPV (net present value) per each simulation "i" considers the incomes and the total costs per each sub-period "t" (4):

$$\text{Objective Function: Maximize RRI} \tag{2}$$

$$\mathrm{RRI} = f\left(\sum_{i=1}^{M} \mathrm{NPV}_i\right) = \frac{E[\mathrm{NPV}_{\mathrm{simulated}}]}{\sigma[\mathrm{NPV}_{\mathrm{simulated}}]} \tag{3}$$

$$\mathrm{NPV}_i = \sum_{t=1}^{T} \frac{Inc_{i,t} - \begin{pmatrix} C_{\mathrm{INV}} + C_{O\&M} + C_{\mathrm{ADG}} + C_{\mathrm{LOSS}} \\ +C_{\mathrm{ESLQ}} + C_{\mathrm{ENS}x\mathrm{Relia.}} + C_{\mathrm{ENS}x\mathrm{Capa.}} \end{pmatrix}_{i,t}}{(1+r)^t}. \tag{4}$$

In order to quantify the investment deferral benefit of DG installation, expansion optimization is divided into two processes: one that poses traditional alternatives in distribution expansion, and another one that considers DG as a flexible investment alternative. Thus, the flexibility value of DG for deferring network reinforcements is derived by the ROV (5):

$$\begin{aligned} \mathrm{ROV} &= \mathrm{NPV}_{\mathrm{flexible}} - \mathrm{NPV}_{\mathrm{traditional}} \\ &= \mathrm{OV}^*_{(t=1)} - \mathrm{NPV}_{\mathrm{robust}}. \end{aligned} \tag{5}$$

A. Technical and Costs Analysis

Power flow calculation and reliability assessment were computed per each "i" simulation and per each "t" sub-period in the initial diagnosis of the network under study and when assessing each expansion alternative within the optimization process.

For power flow calculation at each of the three load steps, a fast and very accurate algorithm developed in a previous work [2] is used. This algorithm computes ac balanced power flows. It is an open framework that allows multi-period calculation of electrical states successively, under normal conditions, significantly reducing computing time. From power flow results and the input data of load duration curves, the three costs are computed: energy losses ($C_{\mathrm{LOSS}\ i,t}$), energy supplied with low quality ($C_{\mathrm{ESLQ}\ i,t}$) and energy not supplied by capacity constraints ($C_{\mathrm{ENS}x\mathrm{Capa}\ i,t}$).

For reliability assessment, a practical and systematic algorithm developed from [3] is used. This algorithm is based on the failure mode and effect analysis technique. It considers the possibility of transferring load among feeders and/or forming isolated microgrids with distributed generators. From each assessment, the expected energy not supplied (ENS) and its corresponding cost ($C_{\mathrm{ENS}x\mathrm{Relia}\ i,t}$) are computed.

The additional variable cost of DG ($C_{\mathrm{ADG}\ i,t}$) is computed from the forecasted demand and electricity price, depending on the type of DG technology to be installed, its location, size, and operation. Incomes ($Inc_{i,t}$) are computed from considering the VAD values (based on the power and energy demand), minus the ENS for both reliability and capacity constraints of lines and distribution substation (D/S).

Before evaluating a DG investment alternative, an analysis of the protection system of the current network is done. The analysis is done "off-line" of the expansion optimization in order to set out viable DG investment alternatives ex-ante. For this analysis, the following main hypotheses, based on [4]–[6], for installing DG on a distribution network are adopted:

a) DG is installed on main feeders of the primary distribution network (MV), but not in lateral branches that usually have fuse protection.
b) When proposing to install a DG unit, the new levels of short-circuit currents should be calculated. Moreover, new fault currents not exceeding the interrupting capability of the main circuit breakers and reclosers already installed on the network should be verified. Otherwise, it is discarded as a DG investment alternative.
c) When investing in DG, directional overcurrent relays ought to be installed on main breakers and reclosers on the same feeder where the DG would be installed. This avoids an improper operation of such breakers and reclosers due to faults occurring in a feeder different (of the same D/S) from the one where DG would be located.
d) The additional cost, if any, of having to install directional relays should be taken into account.

B. Risk-Based Optimization Approach

Fig. 2 shows the general flowchart of the proposed approach, which consists of five stages. Firstly, modeling mathematically the input parameters, distinguishing between deterministic and stochastic ones, is proposed. Secondly, a diagnosis of the current network is made, in order to identify areas with capacity constraints problems and/or voltage drops and/or low reliability considering the forecasted demand. Thirdly, possible expansion variants that would allow to solve such problems are considered; suggesting, on the one hand, traditional variants in distribution expansion, while, on the other hand, considering the possibility of installing DG. Then, in the fourth stage, an optimization of expansion alternatives, with and without DG, is performed, maximizing the RRI (3). Finally, the fifth stage consists in the decision making about the short-term expansion plan to choose.

Regarding the implementation of the EPSO, the first step is encoding the expansion variants suggested by the planning engineer. At this point, the size or dimension of the particles (dim) is specified, as is the number of particles per iteration (np) and the

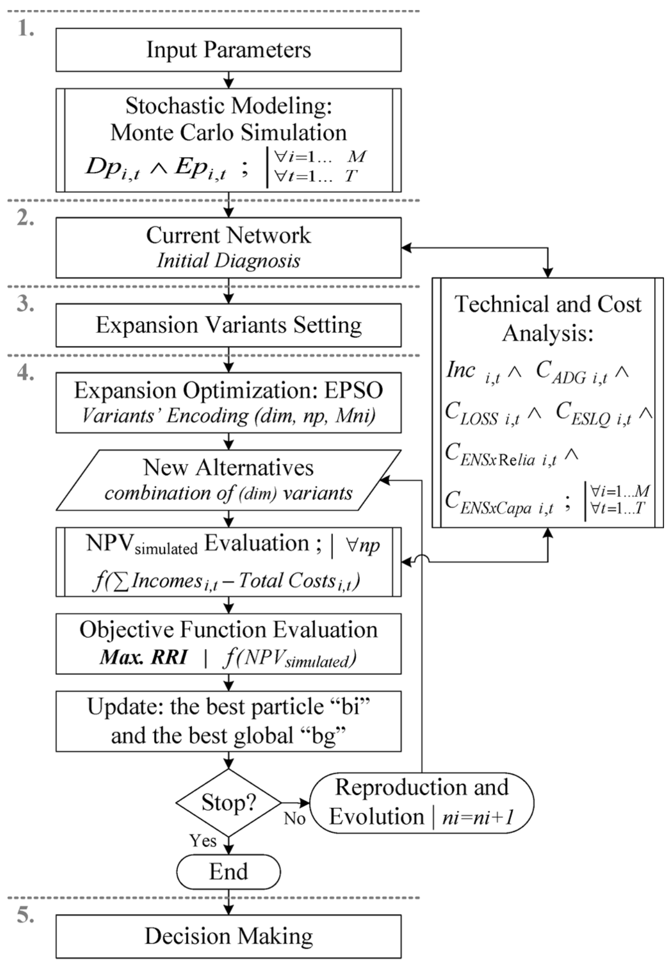

Fig. 2. General flowchart of the risk-based optimization approach.

maximum number of iterations to be evaluated (Mni), where "ni" is an iteration of the expansion optimization. Then, an initial iteration of particles (initial expansion alternatives) is created in order to evaluate its NPV (per each particle or alternative) and then to assess it by means of the objective function (2). The best individual particle "bi" and the best global "bg" are selected in order to maximize RRI. Finally, the stopping criterion of the process is evaluated. Such criterion can be given by a simulation convergence error or by the total quantity of "Mni" iterations to be evaluated. If the stopping criterion is not met, the process creates a new generation of particles through the rules of reproduction and evolution of the EPSO [7], becoming iterative until it fulfills the stopping criterion. As a result, the best global particle is obtained, that is, the BEP (best-compromise expansion plan).

Fig. 3 shows the encoding of expansion variants done in this work, that is, the relationship established between the decisions variables of the real problem (expansion variants) and the elements of the EPSO particles, where:

- The size of the particle (dim) is equal to the total number of the suggested expansion variants.
- Each variant (element of an EPSO particle) is represented by a two-digit integer, where:

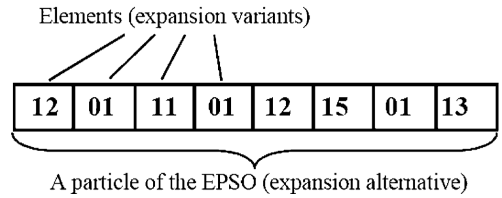

Fig. 3. Encoding of expansion variants.

— The first digit is binary and indicates whether the expansion variant in question is performed or not (0 is not performed).

— The second digit represents the timing at which the expansion investment (year 1, year 2... year 5) is made.

According to this encoding, e.g., Fig. 3, if the first element of the particle represents a variant that performs a new line, code "12" indicates that such line was already performed in the year 2 of this particular alternative.

In order to reduce computational time resulting from the combinatorial explosion of this highly complex optimization problem, distributed computing is used. For this, the easier way is evaluating each EPSO particle in autonomous processors; that is, the "$\mathrm{NPV}_{\mathrm{simulated}}$ Evaluation" per each particle (see Fig. 2) is run in different processors and, then, its results are sent to the scheduler (processor front-end) that runs the rest of optimization process.

C. DG Projects

When evaluating a DG investment alternative, the specific investment costs of each DG technology (US$/kW) are estimated from a fuzzy inference system (FIS) conducted in a previous work by the same authors [8]. The main input of that FIS is the power rating of a DG unit, which is proposed as an investment alternative within the optimization process. In turn, the specific generation costs of DG units (US$/MWh) are also estimated from a self-algorithm of fuzzy inference. In this last algorithm, the main inputs are the electrical efficiency of the DG units and the fossil fuel prices (gas and diesel oil). In this work, the fuel prices growth is modeled by a geometric Brownian mean reverting process. Table I shows some estimated values of the specific costs for three power rating of the three DG technologies under study. Thus, for example, a DG unit of 3 MW of the gas ICE type has an investment cost of US$1500 k (500 US$/MW·3 MW) for peak generation (1100 h) and a total generation cost per year of US$325k (98.5 US$/MWh·3 MW·1100 h), for a gas price of 9.0 US$/MMBtu. In turn, in the same example and regarding the additional cost of DG (see in the first part of this paper [1, Section IV-B]), if the energy price in the wholesale market is 75.5 US$/MWh, the additional variable cost of generation that will be considered within the economic evaluation is 23 US$/MWH (98.5–75.5), which results in an effective annual generation cost of US$75.9k.

Regarding the codification of DG expansion variants, the encoding of EPSO particles adds more than one digit to the particle for traditional expansion variants outlined in Fig. 3. In this case, each element of the particle represents a network's node in which it is possible or feasible to install the DG; the size of the particle (dim) represents the total possible locations in which the

TABLE I
SOME ESTIMATED SPECIFIC COSTS FOR THE THREE DG TECHNOLOGIES

		Power Rating		
		1 MW	3 MW	5 MW
Specific Investment Cost (US$/kW)				
Gas Micro-turbine		1 040	1 000	930
Gas ICE		575	500	364
Diesel ICE		480	430	342
Specific Generation Cost (US$/MWh)				
Gas Micro-turbine				
for a gas price of:	8.0 US$/MMBtu	101.9	92.0	89.4
	9.0 US$/MMBtu	111.5	103.4	100.0
	9.5 US$/MMBtu	115.3	109.1	105.3
Gas ICE				
for a gas price of:	8.0 US$/MMBtu	95.1	88.9	83.4
	9.0 US$/MMBtu	104.9	98.5	92.9
	9.5 US$/MMBtu	109.7	103.3	97.6
Diesel ICE				
for a diesel price of:	0.80 US$/L	227.0	208.5	199.7
	0.90 US$/L	253.9	233.3	223.6
	0.95 US$/L	267.3	245.7	235.6

DG can be installed. Thus, each element of an EPSO particle is represented by a three-digit integer, where:

— The first digit indicates the type and operation of the DG, ranging from 0 to 6; where 0 is DG not installed and 1 is, for example, a gas MT for base-load, 3 is a gas MT for peak generation, 4 is a gas ICE for peak generation, and 6 is a diesel ICE for backup.
— The second digit represents the power rating of the DG unit to be installed, varying between 0 and 9; where e.g., 0 is 0.5 MW, 1 is 1.0 MW, 2 is 1.5 MW, 3 is 2.0 MW, and 9 is 5.0 MW.
— The third digit represents the timing at which the DG investment (year 1, year 2... year 5) is made.

Based on this encoding, for example, if an expansion variant or particle's element turns out to be "431", it indicates that in the node of such element one DG unit of gas ICE was installed for peak generation of 2 MW in the first year.

D. Flexibility Valuation

In the fourth stage of the proposed approach, once the BEP has been obtained (without DG), the real compound options for deferring, switching and abandoning are identified from it in order to consider the DG installation. This is because at first the installation of DG is proposed in order to defer some large investments during the current tariff period, i.e., no more than five years. Then, the DG investment is switched for carrying out the investment which was deferred, abandoning or relocating the DG elsewhere on the network. Thus, the maturity date of real options is at most five years and the strike price of compound option, for each alternative being evaluated, is made up of three components: the cost of investing in DG (to defer any capital-intensive investment), the cost of investment switching (to carry out the project which was deferred), and the salvage value (for abandoning or relocating the DG). In this work, the salvage value of DG is obtained by line depreciation (with a period equal to the depreciation life of the DG), plus an extra cost from uninstalling the DG when there is an investment switch. In Fig. 4 a flowchart diagram is shown in order to clarify the least-squares Monte Carlo simulation (LSM) procedure used to obtain the flexibility value (ROV).

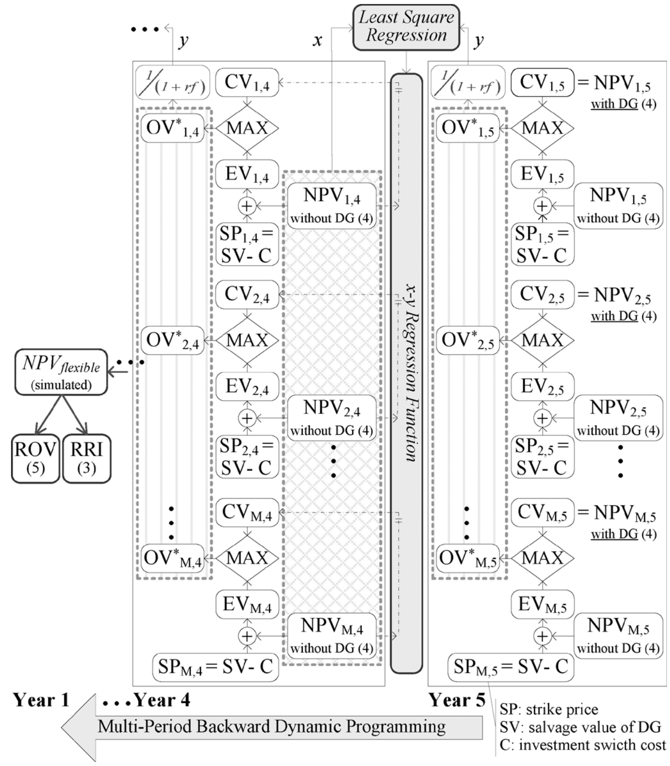

Fig. 4. Real option valuation by the LSM method.

Fig. 4 portrays the evaluation procedure of a compound option for switching and abandoning the DG, assuming that the deferral option was previously exercised by installing DG. In this case, and in each "i" Monte Carlo simulation (up to "M"), the optimal option value (OV^*) at year "t" is derived from comparing the exercising value (EV) of the switching with the continuation value of abandoning option (CV), using backward dynamic programming techniques. The problem starts from the maturity date (year 5) and the working backwards technique is completed at the first year.

III. NUMERICAL RESULTS

A. Testing the Optimization Algorithm

With the aim of checking the convergence of the proposed optimization model, its results are compared with those of the exhaustive method. The test network shown in Fig. 5 was used, which consists of a three-phase balanced feeder of 13.2 kV, two main branches, two lateral branches and two load nodes which set the demand of industrial customers.

Initial peak demand is 3.8 MW in total (1.8 MW and 2.0 MW at nodes D1 and D2, respectively), and the future addition of a big load demand of 2.0 MW at node "D2" is considered. The load factor of both demands is 0.70, with the annual load curve depicted in Fig. 1; the $\cos\varphi$ is 0.85.

Primary distribution MV branches are overhead lines of aluminum alloy conductor steel reinforced (AACSR). The network also has a fixed capacitor bank (C2) of 250 kvar. In the D/S, the power transformer is of 6.25 MVA.

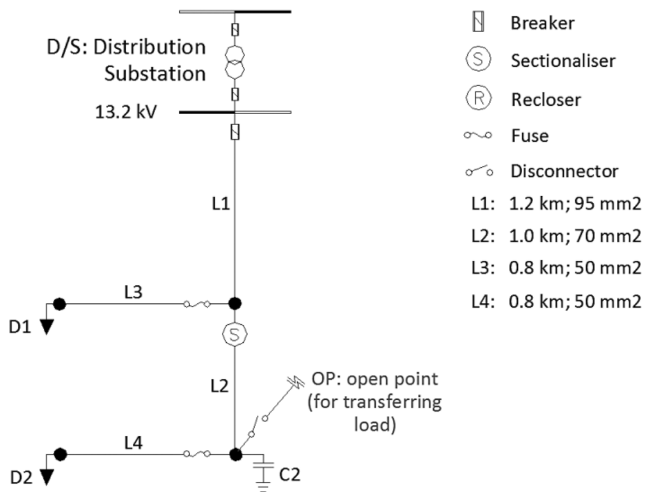

Fig. 5. Test network for testing convergence of the optimization algorithm.

TABLE II
VAD VALUES AND PENALTIES COSTS BY ENS (RELIABILITY)

Customer Type	*Incomes for VAD (tariff):* Fixed Charge (US$/kW-month)	Variable Charge (US$/kWh)	*Reliability:* Cost of ENS (US$/MWh)
Industrial	5.50	0.023	2 250
Commercial	4.90	0.027	1 800
Residential	4.50	0.030	1 500

TABLE III
PENALTY COSTS BY ESLQ (VOLTAGE QUALITY)

Voltage Module (pu)	Cost of ESLQ (US$/MWh)
$0.95 > V \geq 0.93$	100
$0.93 > V \geq 0.90$	150
$0.90 > V$	300

Table II shows the adopted penalty costs for poor reliability and the VAD values. Table III details the penalty costs for poor quality (voltage). Regarding the economic parameters for investment assessment, the annual discount rate is 12% and the analysis period is 15 years with annual sub-periods.

Table IV lists the adopted data for modeling the stochastic input parameters, including the growth of the fuel prices used for estimating the generation costs of DG units. The number of simulations (M) for each Monte Carlo process is 1000. The probability of actually installing the big load demand in the second year is 50%, in the third 30%, and in the fourth year 20% (see Fig. 6).

After the initial diagnosis, six traditional expansion variants were analyzed: expanding the D/S (alternative of higher investment cost); building three parallel lines L1, L2 and L4; and installing two fixed capacitor banks at the end nodes of lines L1 and L2 (see Table V). An exhaustive analysis was made of all possible combinations of these expansion variants, with the aim of finding the best expansion alternative (i.e., the best expansion plan); the three best plans obtained are shown in Table VI.

From these results the decision was made to carry out the larger expansion investment at year 1 (expanding the D/S); the RRI of both the second and the third best plan are 0.05% and 0.53%, respectively, lower than the first one.

Later, within the risk-based optimization approach, the EPSO was applied with the same stochastic input parameters simulated

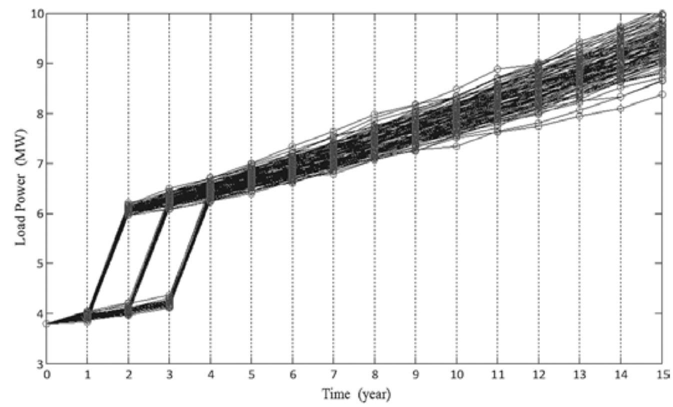

Fig. 6. Stochastic processes that model demand growth.

TABLE IV
ADOPTED DATA FOR STOCHASTIC PARAMETERS

Demand Growth: *GBM (Geometric Brownian Motion)*	
Annual growth rate (drift) = 3.5 %	Standard deviation = 1 %
Purchase Price of Electricity: *Mean Reverting Process*	
Mean reversion rate = 0.15	Standard deviation = 0.12
Initial electricity price = 60 US$/MWh	Long run equilibrium = 100 US$/MWh
Gas Price (fuel for gas DG technologies): *Mean Reverting Process*	
Mean reversion rate = 0.18	Standard deviation = 0.14
Initial gas price = 7.50 US$/MMBtu	Long run equilibrium = 10 US$/MMBtu
Diesel oil Price (fuel for diesel DG units): *Mean Reverting Process*	
Mean reversion rate = 0.20	Standard deviation = 0.25
Initial diesel price = 0.80 US$/L	Long run equilibrium = 1.00 US$/L

TABLE V
EXPANSION INVESTMENTS SUGGESTED

Variant	Description	Investment cost	O&M annual cost
1: L1'	Line AACSR 95 mm^2 (1.2 km)	22 000 US$/km	3 300 US$/km
2: L2'	Line AACSR 70 mm^2 (1.0 km)	20 000 US$/km	3 000 US$/km
3: L4'	Line AACSR 50 mm^2 (0.8 km)	19 000 US$/km	2 850 US$/km
4: Trf	Expanding D/S (6.25 MVA)	2 150 000 US$	5 350 US$ (0.25%)
5: C1'	Fixed capacitor bank (500 kvar)	10 000 US$/Mvar	-
6: C2'	Fixed capacitor bank (500 kvar)	10 000 US$/Mvar	-

TABLE VI
RESULTS OBTAINED FOR THE EXHAUSTIVE ANALYSIS

Best Expansion Plans	L1'	L2'	L4'	Trf	C1'	C2'	RRI
1º: Expanding D/S in year 1; building L4' and installing C1' in year 2; building L1' and L2' plus installing C2' in year 3.	**13**	**13**	**12**	**11**	**12**	**13**	**8.207**
2º: Idem the first expansion plan, but installing C1' in year 1 (instead of year 2)	**13**	**13**	**12**	**11**	**11**	**13**	**8.202**
3º: Idem the first expansion plan, but installing L4' in year 1 (instead of year 2)	**13**	**13**	**11**	**11**	**12**	**13**	**8.163**

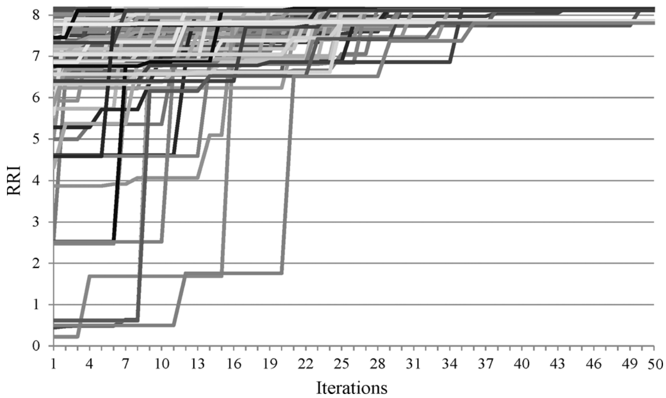

Fig. 7. Convergence of the proposed optimization algorithm (EPSO).

TABLE VII
RESULTS OBTAINED FOR THE PROPOSED OPTIMIZATION ALGORITHM (EPSO)

Success rate of finding the three top best plans	84
Average value of the objective function (RRI)	8.170
Standard deviation of the RRI	0.096 (1.175%)
Maximum value of the RRI	8.207
Minimum value of the RRI	7.804

TABLE VIII
RESULTS OBTAINED FOR 50 TIMES WITH DIFFERENT STOCHASTIC INPUTS

	1° BEP	2° BEP	3° BEP
Frequency of convergence	66%	11%	7%
Average value of the RRI	8.266	8.216	8.119

for the exhaustive analysis. This optimization algorithm was run 100 times for 50 iterations of 10 particles each. Table VII shows the results obtained by the 100th run. The three top BEPs obtained 84% of the time are the same the three best plans obtained by the exhaustive analysis. Fig. 7 shows the convergence of every run of the algorithm.

Given, on the one hand, the negligible differences among the three top BEPs obtained 84% of the time and, on the other hand, that the decision of expanding the D/S at year 1 coincides for those three top BEPs, it can be concluded that the EPSO responds acceptably for solving the expansion problem. Another notable feature is that 94% of the time, EPSO reaches the optimum before the thirtieth iteration.

These results are in harmony with other applications of the EPSO such as, for example, in [9]–[13].

Finally, the risk-based optimization approach was run 50 times (for 50 iterations and 10 particles) by performing different simulations of the stochastic input parameters. Table VIII shows the results of the three top BEPs obtained. These results show that the algorithm finds the 1° BEP 66% of the time, and that it converges to 2° or 3° BEP 18% of the time. These three top BEPs are also the same ones obtained through the exhaustive analysis (as is shown in Table VI).

For this short-term expansion investment decisions, the main objective is to decide which investments should be made at the present time. Because of that, this risk-based analysis is primarily concerned with investment decisions (which expansion

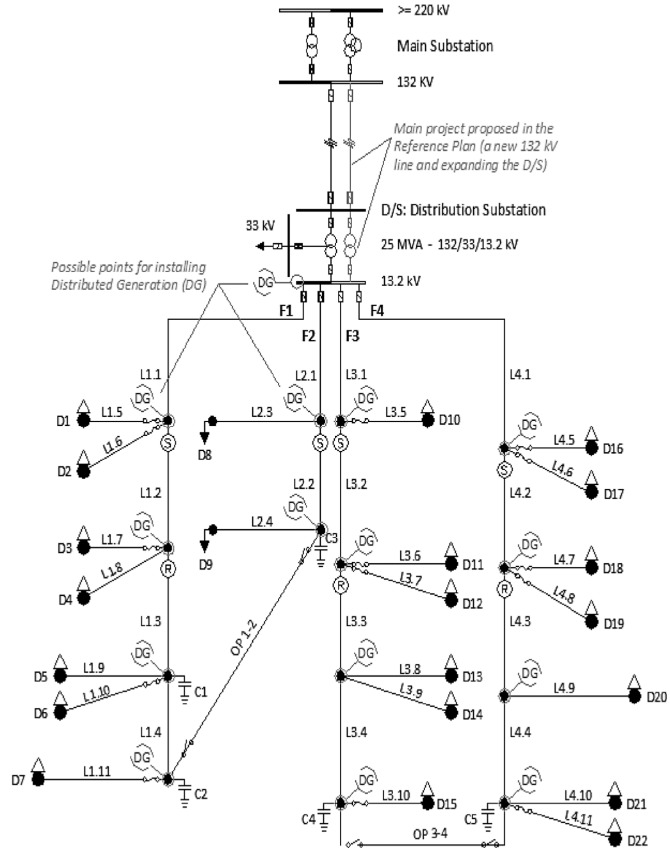

Fig. 8. Single-line diagram of the distribution network under study.

alternative should be chosen) not with numerical solutions by themselves.

B. Case Study

This section discusses the application of the proposed approach for the expansion of a typical Latin American distribution network. Firstly, large investment projects of a long-term reference plan from an "expansion planning" are set out. Secondly, the short-term "investment decisions" are assessed. Specifically, the optimal timing of projects in the reference plan is assessed, along with other potential expansion projects that may arise at this stage.

Fig. 8 shows the network in which the proposed approach was carried out. It is a 13.2-kV three-phase balanced network.

In relation to adopted parameters in order to characterize the demand, Table IX shows the characteristics of customers in the network (residential, commercial and industrial). Table X presents the typical data for all customers grouped by demand nodes. The initial peak load is 20 MW. In the case of all customers, the $\cos\varphi$ is constant and equal to 0.85.

Regarding the adopted parameters for the reference network, Table XI presents the data from primary distribution MV lines. The network also has five fixed capacitor banks of 250 kvar each, located at the end nodes of the main feeders L1.3, L1.4, L2.2, L3.4 and L4.4. The other parameters are the same as those used in the testing network of the previous case (Section III-A), such as the adopted penalty costs for poor reliability and poor

TABLE IX
DEMAND CHARACTERISTIC BY CUSTOMER TYPE

Customer Type	Peak Load (MW)	Annual Load Curve				Load Factor
			Peak	Med.	Min.	
Industrial	9.00	Load ratio respect to the peak power	1	0.750	0.500	0.70
Commercial	3.75		1	0.625	0.400	0.60
Residential	7.25		1	0.350	0.250	0.40
Total :	***20.00***	Hours per year:	1 100	4 760	2 900	

TABLE X
CUSTOMER DATA BY DEMAND NODES

Demand Nodes "D"	Customer Type	Number of nodes "D"	Peak Load (MW)	Number of customers/node
1, 2, 3, 10, 11	Residential	5	0.8668	210
12, 17, 18, 19	Residential	4	0.7291	200
6, 7, 15, 16, 22	Commercial	5	0.7500	10
4, 5, 13, 14, 20, 21	Industrial	6	0.9167	1
8	Industrial	1	1.6279	1
9	Industrial	1	1.8721	1
	Total :	***22***	***20.00***	***1 908***

TABLE XI
OVERHEAD LINES DATA OF FEEDERS

Feeder Lines ("L")	Conductor Type	Number of lines "L"	Lenght (km)
1.1, 4.1, 2.2, 3.2	AACSR 95 mm^2	4	1.00
2.1, 3.1, 1.2, 4.2	AACSR 95 mm^2	4	1.20
1.3, 4.3, 3.4	AACSR 70 mm^2	3	0.75
3.3, 1.4, 4.4	AACSR 70 mm^2	3	0.60
1.9, 2.3, 2.4, 3.9, 4.9	AACSR 50 mm^2	5	0.80
1.8, 3.8, 4.10	AACSR 50 mm^2	3	0.75
1.6, 1.7, 1.11, 3.7, 4.8, 4.11	AACSR 35 mm^2	6	0.80
1.10, 3.6	AACSR 35 mm^2	2	0.75
1.5, 3.5, 3.10, 4.5, 4.6, 4.7	AACSR 35 mm^2	6	0.60
	Total :	***36***	***29.00***

quality, the VAD values, the economic parameters for investment assessment, the data for modeling the stochastic parameters, and the number of simulations (M).

The reference plan originally proposes projects in which two new feeders would be upgraded in the sixth and ninth year. It also proposes expanding the D/S in the first year by installing a new power transformer of 25 MVA; a 132-kV line between the D/S and main substation could also be built. The cost of this large investment is US$ 8200 k.

From the initial diagnosis, a number of new expansion variants were formulated. For this purpose, known reference plan projects and others which arise at this stage and have a lower investment level are taken into account. Among the latter, there are short-term projects such as: upgrading existing feeders (taking into consideration that this project originally arose from the reference plan); evaluating other conductor sections; installing fixed capacitor banks in nodes of main feeders. The investment costs of these expansion variants are the same as those shown in Table V.

TABLE XII
RESULTS OBTAINED FOR THE PROPOSED OPTIMIZATION ALGORITHM (EPSO)

	1° BEP	2° BEP	3° BEP
Frequency of convergence	58%	14%	8%
Average value of the RRI	14.95	14.71	14.56

TABLE XIII
RESULTS OBTAINED FOR THE STUDY NETWORK

Objective Function		Benefit *E[NPV]*	Risk *σ[NPV]*	RRI
Maximize RRI	1° BEP	US$ 2 236k	US$ 151k	**14.8**
	2° BEP	US$ 2 267k	US$ 155k	**14.6**
	3° BEP	US$ 2 279k	US$ 157k	**14.5**
Maximize E[NPV]		US$ 3 431k	US$ 816k	**4.2**
Minimize σ[NPV]		US$ 653k	US$ 68k	**9.6**

1) Expansion Plan Without DG: Subsequently, the risk-based optimization was run 50 times for 50 iterations of 10 particles each. 80% of the time the same three best expansion alternatives turned out, i.e., three coincident BEPs. Table XII shows the results of these three top BEPs. Table XIII shows one of the 50 runs that finds such top BEPs; the first of these BEPs consists of:

- Year 1: expanding the D/S and building the 132-kV line, building a new MV line parallel to main branch L1.1 and installing 2 Mvar of capacitor banks at the end nodes of lines L1.3, L2.2, L3.3 and L4.3.
- Year 2: building new MV lines parallel to main branches L3.1 and L4.1.
- Year 5: building new MV lines parallel to main branches L2.1, L1.2, L3.2 and L4.2.

Table XIII shows that the RRI values of the second and the third BEPs are quite close to the first one. Differences are minimal and are based on the decision of whether to install some capacitors and two MV lines before or after. However, the three BEPs coincide in expanding the D/S in year 1, the highest expansion investment and the more important decision to make. The values of the skewness of NPV probability distribution's are around -0.21 (close to zero), which justify the use of the proposed RRI.

In order to evaluate the performance of the proposed RRI, several other optimization model simulations were made changing the objective function (2). The idea of maximizing the benefit $(E[\mathrm{NPV}])$ was raised, obtaining in all cases BEPs with high values of $E[\mathrm{NPV}]$ but also with high risk values $(\sigma[\mathrm{NPV}])$. The idea of minimizing the risk of investment was also taken into account, obtaining in this case BEPs with very low risk and low $E[\mathrm{NPV}]$. These extreme investment decisions show that in the first case there would be excessive risk in the pursuit of high values of $E[\mathrm{NPV}]$, whereas in the latter there will be a loss in business opportunities in order to minimize risk. Thus, RRI achieves an effective synergy between the expected return on investment and the associated risk. Table XIII shows the representative BEPs of either case. Fig. 9 shows the NPV probability distributions of three cases: the first best BEP obtained maximizing the RRI; the BEP obtained maximizing the $E[\mathrm{NPV}]$ (benefit); and the BEP obtained minimizing the $\sigma[\mathrm{NPV}]$ (risk).

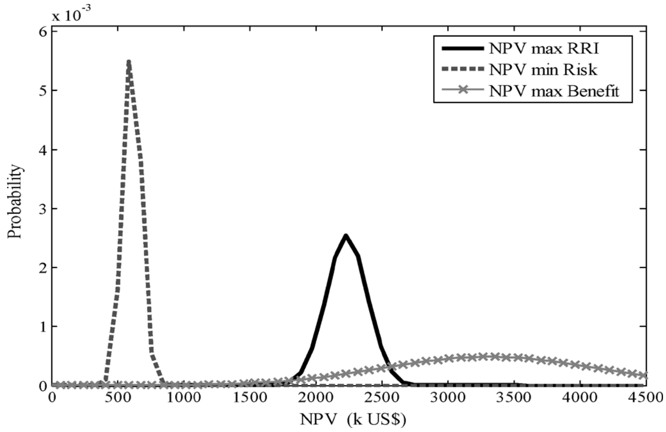

Fig. 9. NPV probability distributions of three different BEP obtained.

TABLE XIV
CASH FLOW OF THE 1° BEP

Expected Values (k US$)	t = 1	t = 2	t = 3	t = 4	t = 5	...	t = 15
Incomes for VAD	1 850	1 915	1 982	2 051	2 123	...	2 998
Total Costs	-8 502	-346	-327	-349	-460	...	-670
Costs for:							
Voltage quality (ESLQ)	*0*	*0*	*0*	*0*	*0*	...	*-4*
Reliability (ENS)	*-156*	*-161*	*-167*	*-172*	*-179*	...	*-252*
ENS by lines capacity	*0*	*0*	*0*	*0*	*0*	...	*0*
ENS by D/C capacity	*0*	*0*	*0*	*0*	*0*	...	*0*
Energy losses	*-104*	*-113*	*-129*	*-145*	*-149*	...	*-368*
Investments	*-8 242*	*-48*	*0*	*0*	*-101*	...	*0*
O&M due to investments	*0*	*-24*	*-31*	*-31*	*-31*	...	*-46*
+ *Residual value of investments*							*4 491*
NPV =	**2 236**						

Table XIV shows the expected cash flow values of the first BEP found by maximizing the RRI, where the expected incomes and the various associated costs are detailed.

Based on the investment decisions of the best expansion plan (the 1° BEP), the optimal timing to end the project of expanding D/S is the first year (confirming what was planned); whereas, a series of investments for expansion can be made in order to achieve an efficient and expected use of the network, upgrading the existing feeders accordingly and getting on with some of the work from the reference plan. In addition, Table XIV shows that what makes a negative impact on the cash flow of the 1° BEP is the large initial investment of US$ 8242 k, where US$ 8200 k correspond precisely to the expanding D/S project. The deferment of this large investment is dealt with in the second step of this study, considering the alternative of installing DG.

2) Expansion Plan Considering DG: Starting with the reference plan and from the 1° BEP obtained in the previous case (without DG), the main and largest investment to be evaluated is expanding the D/S in the first year. With the aim of deferring this large investment, the following DG variants are considered:

- 3 different technologies: gas MT, gas and diesel ICE.
- 3 operation modes: base-load and peak generation (MT and gas ICE), as well as backup generation (both ICE).
- 10 units of 500 kW, power rating: from 0.5 to 5 MW.
- 15 possible locations for installing the DG: the 13.2-kV busbar in the D/S and the 14 nodes of the main feeders.

TABLE XV
RESULTS FOR THE TEST NETWORK

Expansion Plans	Iinitial Investments	Benefit *E[NPV]*	Risk *σ[NPV]*	RRI
1° BEP without DG	US$ 8 242k	US$ 2 236k	US$ 151k	**14.8**
FEP with DG 1	US$ 1 542k	US$ 4 343k	US$ 140k	**31.0**
FEP with DG 2	US$ 1 020k	US$ 3 539k	US$ 140k	**25.3**

Within this framework, the risk-based optimization was run 50 times. Table XV shows the results, obtained in 80% of the runs, of the FEPs (flexible expansion plans) with DG of one run. It shows two plans, one which considers all possible aforementioned locations for installing DG (FEP with DG 1), and another that basically excludes the D/S as a potential location (FEP with DG 2). This second analysis is done in order to verify how the model optimizes the DG installation based on the pre-defined possible locations nodes. As expected, the best location of the DG plant would be at the D/S (FEP with DG 1); but, if a big load demand would be installed in a feeder of the study network, such as in the case presented in Section III-B4, it would be better locating the DG plant close to such big demand.

In particular, the expansion plans obtained consist of:

- *FEP with DG 1:* installing in the first year 3 MW of DG in the MV busbar of D/S, from the type of gas ICE for peak generation. With this, the investment of expanding the D/S is deferred, and the remaining investments are the same from the first BEP obtained in the previous case (without DG).
- *FEP with DG 2:* similar to above but the location, sizing and timing of the DG to be installed changes. This is:
  - — *Year 1:* one unit of 2 MW of gas ICE for peak generation in the end node of line L1.2 (in feeder A1).
  - — *Year 3:* idem, but installing the gas ICE in the end node of line L4.2 (feeder A4).
  - — *Year 4:* two units of 1 MW gas ICE for peak generation, one at the end node of line L2.2 (feeder A2) and another at the end node of line L3.2 (feeder A3).

The expected cash flow values of the FEP with DG 1 and DG 2 are shown in Tables XVI and XVII, respectively, where the different stages of investments, the incomes and their associated costs are presented. The tiny differences in the incomes between the FEP with DG 1 and the FEP with DG 2 are given by their minimal differences in the ENS for reliability and capacity constraints of D/S, which are subtracted from the gross incomes due to the VAD values.

It should be noted that the more important decision to make is which investments to make at the present time (in year 1). For that, Table XV shows the initial investments of each expansion plan. From the next year onwards, the expansion plans will be re-evaluated based on the new information arrived and the best-compromise decision will be made.

Fig. 10 shows the behavior of the NPV of cash flows for the three expansion plans obtained. The same graphic shows the flexibility provided by the DG when moving the expected cash flows to the right (areas of larger NPV).

When considering DG as expansion alternative, the major investment of US$ 8200 k (of the 1° BEP without DG) can be deferred. Table XV shows that in the FEP with DG 1, the RRI

TABLE XVI
CASH FLOW OF THE FEP WITH DG 1

Expected Values (k US$)	**t = 1**	**t = 2**	**t = 3**	**t = 4**	**t = 5**	**...**	**t = 15**
Incomes for VAD	1 850	1 915	1 982	2 051	2 123	...	2 998
Total Costs	-1 802	-394	-370	-389	-8 767	...	-670
Costs for:							
The total investments	*-1 542*	*-48*	*0*	*0*	*-8 301*	...	*0*
Traditional variants	-42	-48	0	0	-8 301		
DG variants	-1 500	0	0	0	0		
The other costs	*-260*	*-346*	*-370*	*-389*	*-466*	...	*-670*
+ Salvage value of DG investments					*1 085*		
+ Residual value of traditional investments							*5 857*
NPV =	**4 343**						

TABLE XVII
CASH FLOW OF THE FEP WITH DG 2

Expected Values (k US$)	**t = 1**	**t = 2**	**t = 3**	**t = 4**	**t = 5**	**...**	**t = 15**
Incomes for VAD	1 855	1 920	1 987	2 057	2 128	...	2 998
Total Costs	-1 309	-357	-1 352	-1 528	-8 760	...	-670
Costs for:							
The total investments	*-1 062*	*-48*	*-1 020*	*-1 150*	*-8 301*	...	*0*
Traditional variants	-42	-48	0	0	-8 301		
DG variants	-1 020	0	-1 020	-1 150	0		
The other costs	*-247*	*-309*	*-332*	*-378*	*-459*	...	*-670*
+ Salvage value of DG investments					*1 728*		
+ Residual value of traditional investments							*5 857*
NPV =	**3 539**						

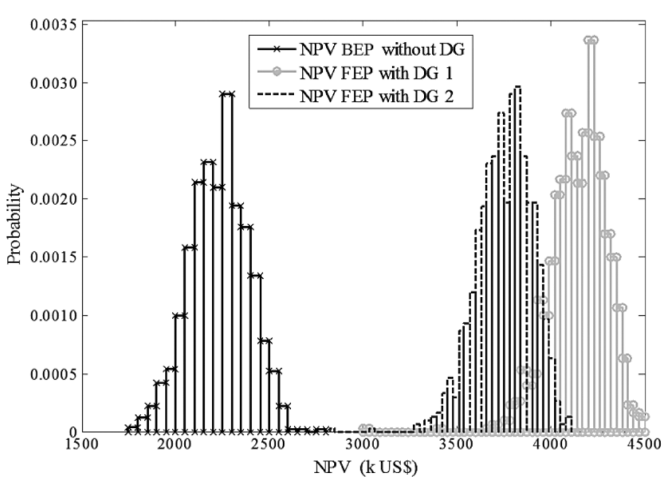

Fig. 10. Distribution of simulative NPV for the three expansion plans.

rate doubles, provided by an increase in returns ($E[\mathrm{NPV}]$), a decreased risk ($\sigma[\mathrm{NPV}]$), and the main initial investment is of US$ 1542 k. For its part, in the FEP with DG 2, the RRI is 1.7 times higher than in the 1° BEP without DG.

Investing in DG results in a saving of initial investment for the utility, until making the large investment for expanding the D/S is justified; or until a maturity date is achieved in order to make such an investment.

Another highlight is the flexibility value of the DG, represented by the ROV (5). In this particular case, for FEP 1, installing 3 MW of DG in the D/S has a ROV of US$ 2107 k. In

TABLE XVIII
MAIN TECHNICAL VALUES OF CURRENT NETWORK WITHOUT NEW PROJECTS

Expected Values			**t = 1**	**t = 2**	**t = 3**	**t = 4**	**t = 5**	**..**	**t = 15**
Growing total demand (MW)			20.7	21.4	22.2	22.9	23.7	..	33.5
D/S	Power capacity (MVA)		25	25	25	25	25	..	25
	Total power flow (MVA)		24.5	***25.5***	***26.4***	***27.4***	***28.4***	**..**	***41.3***
Total current flow (A)		L1.1	***310***	***321***	***334***	***346***	***360***	..	526
		L2.1	184	191	198	205	213	..	306
		L3.1	272	282	292	303	***315***	..	456
		L4.1	298	***309***	***320***	***332***	***344***	..	499

TABLE XIX
MAIN TECHNICAL VALUES OF 1° BEP AND FEP WITH DG 1

Expected Values			**t = 1**	**t = 2**	**t = 3**	**t = 4**	**t = 5**	..	**t = 15**
D/S	Power capacity (MVA)	1° BEP	25	***50***	***50***	***50***	***50***	..	***50***
		FEP 1	25	***28***	***28***	***28***	***28***	..	***50***
	Total power flow (MVA)		24.0	24.5	25.4	26.3	27.2	..	39.4
Total current flow (A)		L1.1	305	313	325	337	347	..	504
		L2.1	184	185	190	198	205	..	296
		L3.1	261	268	278	289	298	..	431
		L4.1	287	295	304	318	327	..	474

contrast, for the second FEP, installing four units of DG (one in each feeder), has a ROV of US$ 1303 k. These flexibility values would be the absolute "extraordinary" expected value, as regards the money that DG would add to the utility if the decision to invest in DG is made.

3) Discussion of the Expansion Plans Achieved: With the aim of assessing the expansion plans achieved with the proposed optimization model, in this section such plans are analyzed and contrasted with other expansion plans.

Firstly, within the initial diagnosis, the expected technical values of the network under study without new investment projects are shown in Table XVIII. These values show that the D/S has problems of excess power capacity from year 2. In turn, the main branch of feeder A1 (line L1.1) has problems of thermal capacity violations from year 1 onwards. The same event happens with lines L4.1 and L.3.1 from years 2 and 5, respectively. The capacity of these lines is 305 A.

Secondly, Table XIX presents the expected technical values of the network after performing the expansion plans of the 1° BEP without DG and the FEP with DG 1. The difference between these plans is that in the 1° BEP, the expanding D/S project is performed, while in FEP 1 the DG installation on MV busbar of D/S is performed. The remaining investments are the same in both plans, 1° BEP and FEP 1. Among the remaining investments there is the building of new MV lines parallel to main branches for doubling their capacity.

Regarding the DG investments and expanding the D/S, it is noted that their construction and installation have a delay time of one year from the time when the investment decision is made (and, consequently, from when such investment is paid).

Thirdly, Table XX presents the expected technical values resulting from performing the FEP with DG 2. In this case, the optimization model achieves the installation of one DG unit of 2 MW in line L1.2 (same feeder of L1.1) on year 1, starting work

TABLE XX
MAIN TECHNICAL VALUES OF FEP WITH DG 2

Expected Values			t = 1	t = 2	t = 3	t = 4	t = 5	..	t = 15
D/S	Power capacity (MVA)		25	25	25	25	25	..	50
	Total power flow (MVA)		24.0	23.0	23.7	22.8	24.3	..	39.4
Total current flow (A)		L1.1	305	***251***	***254***	***257***	***297***	..	504
		L2.1	184	185	190	198	***184***	..	296
		L3.1	261	268	278	289	***270***	..	431
		L4.1	287	295	304	***246***	***279***	..	474

TABLE XXI
COMPARISON OF OTHERS SUBOPTIMAL FEPS WITH DG 2

	FEP with DG 2	plan 1	plan 2	plan 3	plan 4	plan 5
line	1 2 3 4	1 2 3 4	1 - - 4	1 2 3 4	1 2 3 4	1 2 3 4
node	2 2 2 2	2 2 2 2	2 - - 2	1 1 1 1	2 1 1 2	2 2 2 2
type	4 4 4 4	4 4 4 4	4 - - 4	4 4 4 4	4 4 4 4	3 3 3 3
MW	2 1 1 2	2 1 1 2	1.5 - - 1.5	2 1 1 2	2 1 1 2	2 1 1 2
year	1 4 4 3	1 4 4 2	1 - - 3	1 4 4 2	1 4 4 3	1 4 4 2
RRI	**25.3**	**24.5**	**10.4**	**23.3**	**24.9**	**18.2**
NPV	US$ 3539k	US$ 3476k	US$ 3788k	US$ 3446k	US$ 3594k	US$ 2583k
Risk	US$ 140k	US$ 142k	US$ 362k	US$ 148k	US$ 144k	US$ 142k

on year 2. Two years later, it achieves the installation of another DG unit of 2 MW in line L4.2 on year 3, starting work on year 4. At last, two DG units of 1 MW are installed on year 4. These achieved investment decisions are mainly based on avoiding the power capacity restriction of D/S, while its expanding project is deferred.

Fourthly, other "intuitive and logical" expansion strategies are proposed and optimized in order to contrast the FEP with DG 2. Table XXI shows other five plans similar to the FEP 2, which are suboptimal or worse than FEP 2 (in terms of the RRI), with the following characteristics:

- Plan 1 proposes to install the DG unit of 2 MW in line L4.2 before of the third year. In this case, the optimization model achieves the installation of such DG unit on year 2 as the best-compromise solution.
- Plan 2 aims to install the same total generation capacity goes from the FEP with DG 1 (3 MW), instead of 6 MW from the FEP 2. The optimization model achieves to install one DG unit of 1.5 MW in the line L1.2 and another one of 1.5 MW in the line L4.2; but the *IRR* was 10.4, mainly due to power capacity violations of D/S.
- Plans 3 and 4 search for changing the nodes chosen by the optimization model to install the DG units. In plan 3 the four nodes closest to the S/D are chosen.
- Plan 5 proposes to install other DG technology. In this case, it is achieved to install gas MT for peak generation.

4) Sensitivity Analysis: Fig. 11 shows the sensitivity of the expansion plans obtained, specifically, the 1° BEP without DG and the FEP with DG 1, in terms of the investment cost to be deferred, i.e., the project of expanding the D/S. The abscissa axis of Fig. 11 shows the proportion of cost variation in the investment to be deferred. That is, for the base case shown in the graph with value of one ("1"), the investment cost to be deferred is US$ 8200 k, and the investment cost in DG is US$ 1500 k,

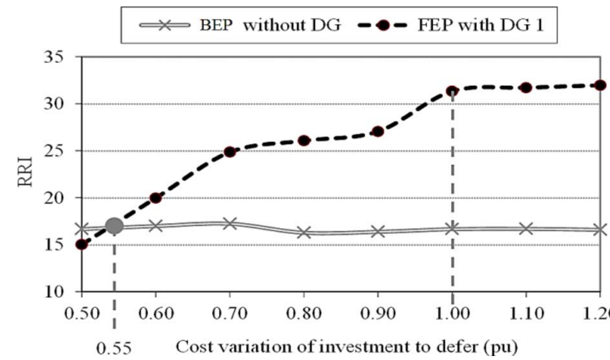

Fig. 11. Sensitivity of the BEP without DG and the FEP with DG 1.

TABLE XXII
RESULTS OBTAINED CONSIDERING A JUMP IN POWER DEMAND

Expansion Plans	Iinitial Investments	Benefit *E[NPV]*	Risk *σ[NPV]*	RRI
BEP without DG	US$ 8 252k	US$ 2 628k	US$ 125k	**21.0**
FEP with DG 1	US$ 1 852k	US$ 4 441k	US$ 124k	**35.8**
FEP with DG 2	US$ 1 542k	US$ 6 287k	US$ 124k	**50.7**

which implies a ratio of 5.47 (8200/1500), i.e., the deferred investment is 5.47 more costly than the DG. Thus, for example, increasing 10% the cost of the investment to be deferred represents a value of "1.10" in the graph, which, keeping the cost of investing in DG constant, the relationship between the deferring cost and DG in this case would be 6/1 times (9020/1500).

Fig. 11 shows that, as the value of the investment which is deferred decreases, the flexibility value of the DG decreases as well, i.e., the RRI of FEP with DG 1 is reduced. The indifference point, in this particular case, is provided by a ratio indicating that the cost of investment to be deferred is about 3 times higher than the cost of investing in DG. This is so for an investment cost of the order to be deferred of US$ 4500 k (value of "0.55").

5) Adding a New Big Demand: The likelihood of installing a big load demand on the study network is considered. The demand for this big customer is 1.5 MW and is expected to be installed in the node "D9". The probability of actually installing it in the first year is 50%, in the second 30%, and in the third year 20%. This new context makes expansion plans change as seen in Table XXII, which shows the results of one run obtained 80% of times.

The investment difference in this new BEP without DG, from which was obtained in the previous case (1° BEP in the Table XV), comes from making 1.8 km more of MV lines. Obtaining a higher $E[\mathrm{NPV}]$ and better RRI in the BEP than in the previous case is due to a better use of the network, especially the expanding of D/S. That is, technically, the network expansion is better adapted to demand in terms of power capacity. This shows that the BEP without DG can be considered a robust plan, as it acceptably withstands the uncertainty of a jump in demand without major changes.

On the other hand, as regards flexible expansion plans, it can be stated that with DG it is possible to manage risk better, due to the uncertainty in the demand jump. This is manifested in the FEP with DG 2, obtaining a ROV of US$ 3659 k and an RRI 2.4 times higher than the BEP without DG.

C. Computational Performance

The simulations have been run in the MATLAB® environment on three computers with a 2.8-GHz Intel® Core™ i5 processor of four cores and 4 GB of RAM.

The process that takes the most time to calculate is the power flow calculation, because of the number of times have to run it. For this particular case, within the comprehensive optimization approach, the power flow calculation ended up running around 22.5 million times per each optimization run. That took up about 60% of the total simulation time.

Based on the algorithm used for power flow calculation [2] and for the studied case of a typical distribution network (Section III-B), a run of power flow takes about 0.125 ms and 0.100 ms with and without DG, respectively. Thus, through distributed computing (with 10 cores per every 10 particles of the EPSO), a run of the proposed optimization approach takes about 9 min and 7 min considering DG and without it, respectively. Finally, running 50 times the full optimization approach takes in total about 16 h.

If the number of calculating cores is doubled, the total time for running the optimization approach is approximately reduced in half. That is, in the above mentioned case, 20 cores (five PCs i5) take about 9 h for a full run. Thus, for example, when planning a network of 500 nodes with ten PCs i7 (80 cores) a full run takes about 25 h.

IV. Conclusion

This work develops a risk-based optimization approach for distribution expansion planning, considering DG plants as expansion options to defer network reinforcements. The proposed optimization algorithm is based on the EPSO method, performing Monte Carlo simulations for modeling stochastic uncertainty; it performs acceptably in solving the expansion problem. An index of return-per-risk is proposed which measures risk-adjusted returns when comparing expansion investment alternatives. The benefit of network investment deferral (with DG of lower cost and reversible investment) is assessed by real option valuation. The impact of DG on energy losses, voltage and reliability is also assessed. The type of DG technology to be installed, its location, size, operation, and timing are jointly optimized within the proposed approach.

The greatest contribution of the DG lies in the flexibility it gives to the distribution expansion, mainly by deferring large investments. This is economically viable when the investment cost to be deferred is about three times or more the cost of investing in DG.

The more uncertainty there is, the more interest in having a flexible option for expansion, because the greater the value of flexibility (ROV) granted by the DG. Peculiarly, the major uncertainty comes from demand, especially when a big demand is expected in the future.

Thus, it can be concluded that utilities can invest in DG; it is a feasible option that should be considered and compared to traditional power supply, with the goal of achieving energy efficiency. If utilities are allowed to own and operate DG, it can be a valuable expansion option, so as to change and/or defer large investments, and in some cases, to improve the quality of service. If only private investors are allowed, utilities can use this approach in order to offer additional payments for investors who decide to install DG units in strategic locations of the networks.

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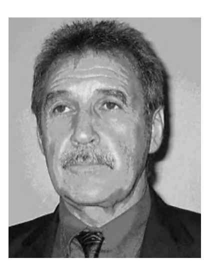

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