Joint Distribution Network and Renewable Energy Expansion Planning Considering Demand Response and Energy Storage—Part II: Numerical Results

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***Abstract*—The second part of this two-paper series analyzes the incorporation of demand response (DR) and energy storage systems (ESSs) in the joint distribution and generation expansion planning for the isolated system of La Graciosa, Canary Islands, Spain. Based on the stochastic programming model developed in its companion paper, the impact of DR and ESS on the location and size of new generation and storage units and the distribution assets to be installed, reinforced, or replaced are defined. Numerical results illustrate the effective performance of the proposed approach. Additionally, a set of metrics showing the welfare achieved by the different stakeholders has been implemented.**

***Index Terms*—DR, RES (renewable energy sources) expansion planning, distribution network expansion planning, ESS, distribution systems.**

Nomenclature

The symbols listed here are used in this paper only. For the definition of the remaining symbols also used in this paper, the reader is referred to the Nomenclature Section of the companion paper [1].

Variables

- lBC^* — Aggregate benefit of the consumers when considering DR and/or ESS in the model formulation.
- BC^0 — Aggregate benefit of the consumers disregarding DR and ESS in the model formulation.
- BD^* — Aggregate benefit of the distribution and generation planner when considering DR and/or ESS in the model formulation.
- BD^0 — Aggregate benefit of the distribution and generation planner disregarding DR and ESS in the model formulation.
- INV^* — Investment costs to be undertaken by the generation and distribution planner
- SW^* — Aggregate social welfare including the benefits for the generation and distribution company and the benefits for the consumers when considering DR and/or ESS in the model formulation.
- SW^0 — Aggregate social welfare including the benefits for the generation and distribution company and the benefits for the consumers disregarding DR and ESS in the model formulation.
- μ_1, μ_2, μ_3 — Metrics for expansion planning.

Manuscript received June 10, 2015; revised December 17, 2015 and March 8, 2016; accepted April 24, 2016. Date of publication April 28, 2016; date of current version February 16, 2018. This work was supported in part by the European Union 7th Framework Programme FP7/2007-2013 through Project SiNGULAR under Grant 309048, in part by the Ministry of Economy and Competitiveness of Spain under Project ENE2015-63879-R (MINECO/FEDER, EU), in part by the Junta de Comunidades de Castilla-La Mancha under Project POII-2014-012-P and Grant PRE2014/8064, and in part by the Universidad de Castilla-La Mancha under Grant GI20152945. Paper no. TSG-00655-2015.

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Digital Object Identifier 10.1109/TSG.2016.2560341

I. Introduction

The FIRST paper [1] presents a novel dynamic stochastic programming model for the co-optimized expansion planning problem wherein uncertainty of demand and renewable generation is explicitly modeled through a set of scenarios, stressing the importance of integrating DR to time-varying prices into investment models. The proposed approach differs from the state of the art [2]–[6] from both a modeling perspective and a methodological viewpoint. References [2] and [3] have shown the benefits of a chronological approach to efficiently integrate time dependent resources in the expansion planning. However, the limited forecast accuracy for yearly periods and the low tractability of the problem when applied to various years, make the proposed approach infeasible. In medium- and long-term planning models is a common approach to approximate the demand curve by load levels [4]–[6]. As a distinctive modeling feature, uncertainty characterization preserves the correlation among load, wind power generation, and photovoltaic generation, resulting in adequate signals for DR and ESS.

This paper is organized as follows. In Section I, the test system of La Graciosa and the corresponding results are presented. Four case studies have been presented accounting for the introduction of price-dependent resources. Metrics considered for the joint generation and distribution expansion planning are provided in Section II. Some relevant conclusions are drawn in Section III. Finally, network data for the considered system are provided in the Appendix.

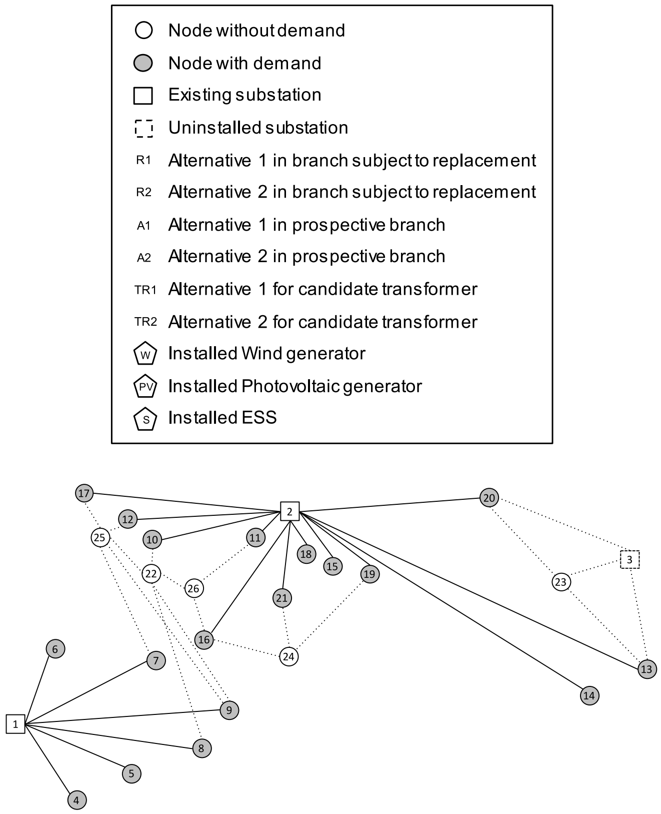

Fig. 1. One-line diagram of the La Graciosa distribution network.

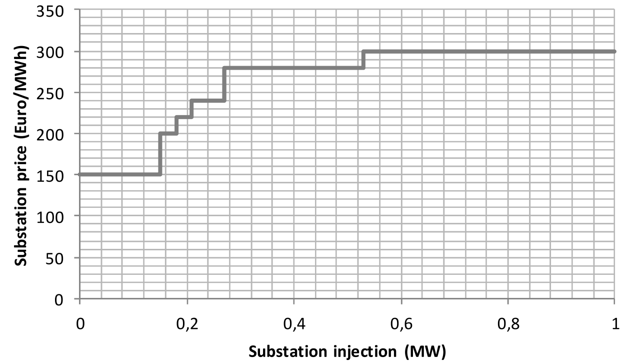

Fig. 2. Substation price scenarios.

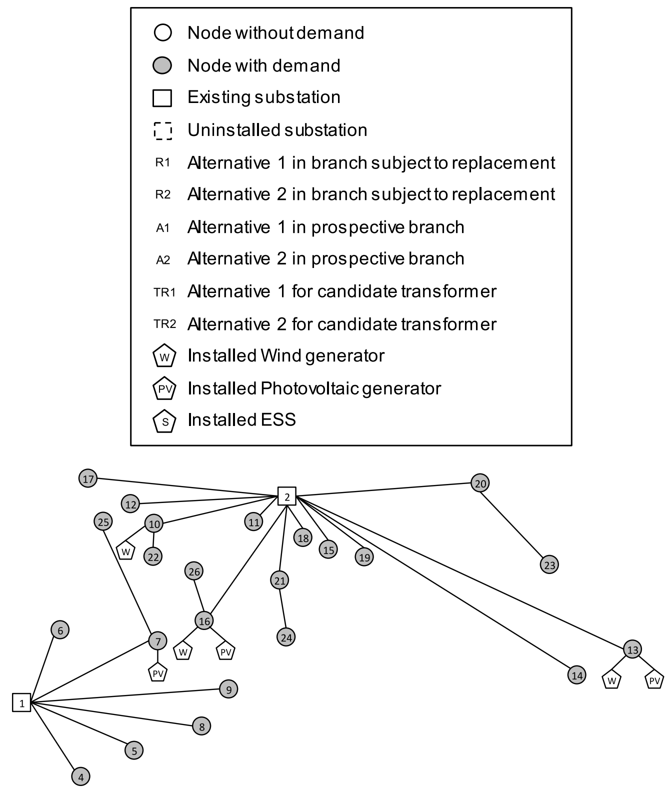

Fig. 3. One-line diagram of the La Graciosa distribution network expansion without DR and ESS.

II. Case Study

A. System Description

La Graciosa is a small island belonging to the Canary Islands located near Lanzarote, consisting of 26 nodes and 37 branches. La Graciosa is connected to the Lanzarote-Fuerteventura electric power system. The distribution network analyzed consists of 23 load nodes, 3 substation nodes, and 37 branches (Fig. 1). The data corresponding to the considered distribution network are presented in the Appendix.

The base power and base voltage of the system are 1 MVA and 20 kV, respectively. A 3% interest rate is set. The lifetime of all feeders and transformers is 30 years. For simplicity, maintenance costs for all feeders are equal to €450/year. The cost of unserved energy, C^U, is €2,000/MWh. Investment in DG is allowed with a penetration limit, ξ, set to 40%. The investment budget is set to €70,000 for each period. Candidate nodes for installation of wind generators are 8, 9, 10, 11, 12, 13, 15 and 16. Candidate nodes for installation of PV generators are 7, 8, 9, 12, 13, 14, 16, and 21. Candidate nodes for installation of storage units are 9, 15, 20, and 23. Upper and lower bounds for voltages at load nodes are equal to 1.05 p.u. and 0.95 p.u.

With the aim of adequately include price-dependent resources in the proposed generation and distribution expansion planning, substation prices for the transmission and distribution connection nodes have been defined as dependent on the total injected power in the distribution network (Fig. 2). Considering typical variable generation costs for isolated systems, Fig. 3 represents the considered substation prices. The proposed approach is consistent with the traditional methodology where higher prices are charged to higher substation consumptions, following the rules of the marginal pricing price setting. The proposed model considers a single transmission system connected with La Graciosa distribution network. The prices assumed for the proposed model are consistent with those provided by REE for the Lanzarote-Fuerteventura subsystem [8].

The planning horizon is 15 years subdivided into five periods of three years. This consideration is used because of the high investment costs of the long-term planning elements, requiring a longer period to check investment return. Despite the actions being taken every three years, an annual load

TABLE I
CASE 1: INVESTMENT DECISIONS IN THE 15-YEAR EXPANSION PLANNING

Investment	**Stage 1**	**Stage 2**	**Stage 3**	**Stage 4**	**Stage 5**
PV	N13, N16	N7	-	-	-
Wind	N10, N13	N16	-	-	-
Storage	-	-	-	-	-
Line Replacement	-	-	-	-	-
New Line	N10 – N22(1), N20 – N23(1)	N7 – N25(1)	N16 – N26(1)	N21 – N24(1)	-
New Substation	-	-	-	-	-

TABLE II
CASE 1: OPERATING AND INVESTMENT COSTS [THOUSANDS OF €]

Costs	**Stage 1**	**Stage 2**	**Stage 3**	**Stage 4**	**Stage 5 − 10**	*Total*
Investment	66.6	32.7	2.9	5.0	0.0	112.2
O&M	12.0	14.3	14.3	14.8	88.6	140.0
Energy purchased	433.9	507.8	580.6	601.0	3928.3	6051.6
Unserved energy	0.0	0.0	0.0	0.0	0.0	0.0
Total	512.5	554.8	594.9	620.8	4016.9	6303.8

growth for each node is considered [2]–[7]. New demand nodes appear over the considered time horizon (period 1: nodes 22 and 23, period 2: node 25, period 3: node 26, period 4: node 24) in order to analyze the impact of DR and ESS on the distribution network expansion planning. The alternatives considered for the added and replaced lines are presented in parenthesis.

B. Results

1) Results Without Demand Response and Storage: The results obtained by the expansion planning algorithm for the case study without DR and ESS are presented in Tables I, II and III. Table I represents the investment decisions, while Tables II and III summarize overall costs and payment of the demand, respectively. The outcomes of this model will be considered as base case to analyze the impact of DR and ESS in the joint generation and distribution expansion planning model.

The numerical results presented in Table II represent how to expand generation and the distribution network adding DG and new assets (lines and substations) so that the current and future energy supply are served at a minimum cost. Investment costs are amortized in annual payments during the lifetime of the installed equipment, considering that once the component is operated during a time equal to its lifetime, there is a reinvestment in identical equipment, so infinite annual updated payments are used. The remaining costs related to operation are updated and these costs are kept indefinitely, taking into account an infinite series of annual payments. The total payment of the final consumers is presented in Table III.

TABLE III
CASE 1: PAYMENT OF THE DEMAND [THOUSANDS OF €]

	Stage 1	**Stage 2**	**Stage 3**	**Stage 4**	**Stage 5 − 10**	*Total*
Payment	736.7	885.2	1012.8	1049.4	6969.5	10653.5

TABLE IV
CASE 2: INVESTMENT DECISIONS IN THE 15-YEAR EXPANSION PLANNING

Investment	**Stage 1**	**Stage 2**	**Stage 3**	**Stage 4**	**Stage 5**
PV	N13, N16	N12	-	N14	-
Wind	N10, N16	N13	-	-	-
Storage	-	-	-	-	-
Line Replacement	-	-	-	-	-
New Line	N10 – N22(1), N13 – N23(2)	N12 – N25(1)	N16 – N26(1)	N21 – N24(1)	-
New Substation	-	-	-	-	-

The planning horizon is 15 years subdivided into five periods of three years. Investment decisions are considered to be made during these periods. The lifetime of all feeders and transformers and generation technologies has been set to 30 years. The column entitled “Stage 5-10” represents the costs incurred by the central planner and consumers during the last period of the planning horizon and the five successive periods.

The final situation of the distribution system of La Graciosa is presented in Fig. 3, showing the expansion of the distribution network to cover the expected demand increase and the installation of distributed generation within the distribution network.

2) Results With Demand Response: Results for the case study with DR are presented in Tables IV, V and VI.

The study demonstrates that the effect of DR in the model is the deferment of the capacity enhancement driven by natural demand growth. Investment in renewable technologies in the first period has been reduced. During the second, third and fourth periods, deferred investments take place. Tables V and VI show the aforementioned effects. The model results in a total payment of the demand lower than in the first case, where DR has not been considered. The overall purchased energy cost decreases over the five considered periods, as a consequence of load shifting from high to low energy prices.

The total costs for generation and distribution are reduced over the considered period, as well as the total payment of the consumers. Consumers should have the opportunity to receive and respond to prices or signals that reflect time varying conditions. The long-term benefit allowing demand to respond to time-varying price conditions is a flatter load shape, which should reduce the need for peaking capacity and, in turn, reduce emissions and costs through the more effective and efficient use of the grid. Both, generation and distribution and the

TABLE V
CASE 2: OPERATING AND INVESTMENT COSTS [THOUSANDS OF €]

Costs	***Stage* 1**	***Stage* 2**	***Stage* 3**	***Stage* 4**	***Stage* 5 – 10**	***Total***
Investment	68.3	32.7	2.9	13.8	0.0	131.9
O&M	12.0	14.3	14.3	15.6	91.9	149.5
Energy purchased	429.2	496.5	561.3	583.8	3694.9	5754.3
Unserved energy	0.0	0.0	0.0	0.0	0.0	0.0
Total	509.5	543.5	578.5	613.2	3786.8	6047.1

TABLE VI
CASE 2: PAYMENT OF THE DEMAND [THOUSANDS OF €]

	***Stage* 1**	***Stage* 2**	***Stage* 3**	***Stage* 4**	***Stage* 5 – 10**	Total
Payment	735.1	874.5	1001.4	1034.7	6892.8	10538.6

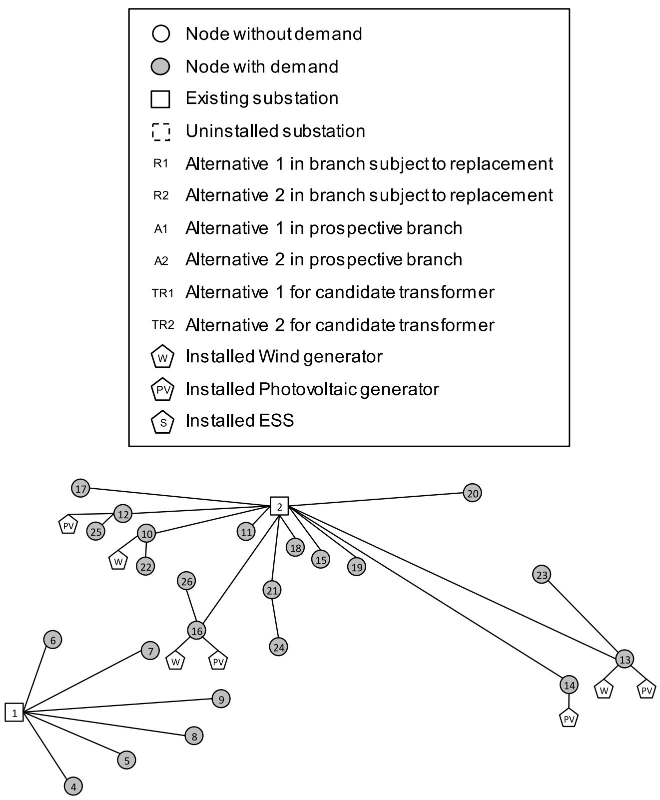

Fig. 4. One-line diagram of the La Graciosa distribution network expansion with DR.

final consumers are benefited from the exposure of consumers to time-varying prices.

The final situation of the distribution system of La Graciosa is presented in Fig. 4. Comparing the results with the previous case, it is worth outlining the modification on the distribution network expansion planning. Additionally, as a result of the integration of DR in the expansion planning model, the overall RES penetration in the system increases, showing the adequacy of the proposed characterization of uncertainty.

3) Results With Storage: Results for the case study with ESS are presented in Tables VII, VIII and IX.

TABLE VII
CASE 3: INVESTMENT DECISIONS IN THE 15-YEAR EXPANSION PLANNING

Investment	***Stage* 1**	***Stage* 2**	***Stage* 3**	***Stage* 4**	***Stage* 5**
PV	N13, N16	N7	-	-	-
Wind	N10, N13	N16	N11	-	-
Storage		N9	N23	-	-
Line Replacement	-	-	-	-	-
New Line	N10 – N22(2), N13 – N23(1)	N9 – N25(2), N22 – N26(2)	-	N21 – N24(1)	-
New Substation	-	-	-	-	-

TABLE VIII
CASE 3: OPERATING AND INVESTMENT COSTS [THOUSANDS OF €]

Costs	***Stage* 1**	***Stage* 2**	***Stage* 3**	***Stage* 4**	***Stage* 5 – 10**	***Total***
Investment	68.3	64.5	26.3	3	0	159
O&M	11.9	15.8	17.1	17.5	105.2	167.4
Energy purchased	433.9	505.9	586.5	597.4	3843.5	5967.2
Unserved energy	0.0	0.0	0.0	0.0	0.0	0.0
Total	514.1	586.2	629.9	617.9	3948.7	6293.6

TABLE IX
CASE 3: PAYMENT OF THE DEMAND [THOUSANDS OF €]

	***Stage* 1**	***Stage* 2**	***Stage* 3**	***Stage* 4**	***Stage* 5 – 10**	***Total***
Payment	736.7	893.3	1032.2	1062.7	7040.0	10765.0

The study demonstrates that the effect of ESS in the model accelerates the investment in DG renewable technologies (including ESS). Investment in storage takes place during the second, third and fourth periods, significantly increasing the overall investment. The overall purchased energy costs are reduced over the five considered periods when compared with the first case, as a consequence of the management of the installed storage systems. Additionally, the overall payment of the consumers increases over the considered time horizon for the same reason. Network investments have been shifted to the first period due to the investment budget constraint, since the investment in storage technologies takes place during the second period.

The total costs for generation and distribution are reduced over the considered period. The operational analysis of the system provides a hint that energy storage investment is a feasible solution with increased wind and solar penetration. The final situation of the distribution system of La Graciosa is presented in Fig. 5.

4) Results With Demand Response and Storage: Results obtained by the expansion planning algorithm for the case study with demand response and hybrid storage are presented in Tables X, XI and XII.

The introduction of demand response and storage in the model accelerates the investment in renewable technologies,

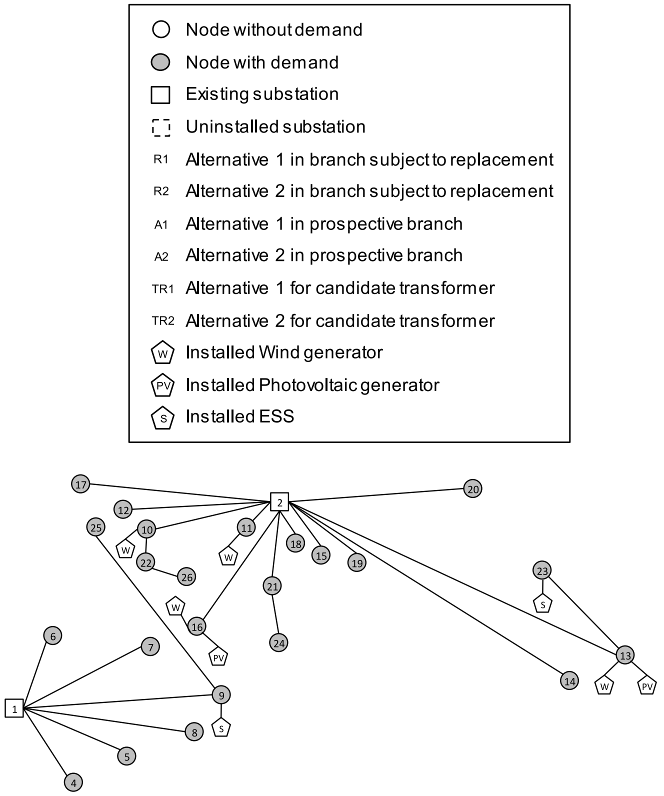

Fig. 5. One-line diagram of the La Graciosa distribution network expansion with ESS.

TABLE X
CASE 4: INVESTMENT DECISIONS IN THE 15-YEAR EXPANSION PLANNING

Investment	**Stage 1**	**Stage 2**	**Stage 3**	**Stage 4**	**Stage 5**
PV	N13, N16	N7	-	N14	-
Wind	N10, N13	N16	-	-	-
Storage	-	N20	N23	-	-
Line Replacement	-	-	-	-	-
New Line	N10 – N22(2), N13 – N23(2)	N22 – N25(1)	N16 – N26(1)	N21 – N24(1)	-
New Substation	-	-	-	-	-

TABLE XI
CASE 4: OPERATING AND INVESTMENT COSTS [THOUSANDS OF €]

Costs	**Stage 1**	**Stage 2**	**Stage 3**	**Stage 4**	**Stage 5 – 10**	*Total*
Investment	68.6	39.9	11.9	13.8	0	134.2
O&M	12	14.3	15.2	16.2	97.3	155
Energy purchased	433.9	494.6	561.4	580.2	3596.4	5866.5
Unserved energy	0.0	0.0	0.0	0.0	0.0	0.0
Total	514.5	548.8	588.5	610.2	3993.7	6155.7

TABLE XII
CASE 4: PAYMENT OF THE DEMAND [THOUSANDS OF €]

	Stage 1	**Stage 2**	**Stage 3**	**Stage 4**	**Stage 5 – 10**	*Total*
Payment	735.1	888.6	1024.5	1055.7	7003.2	10707.2

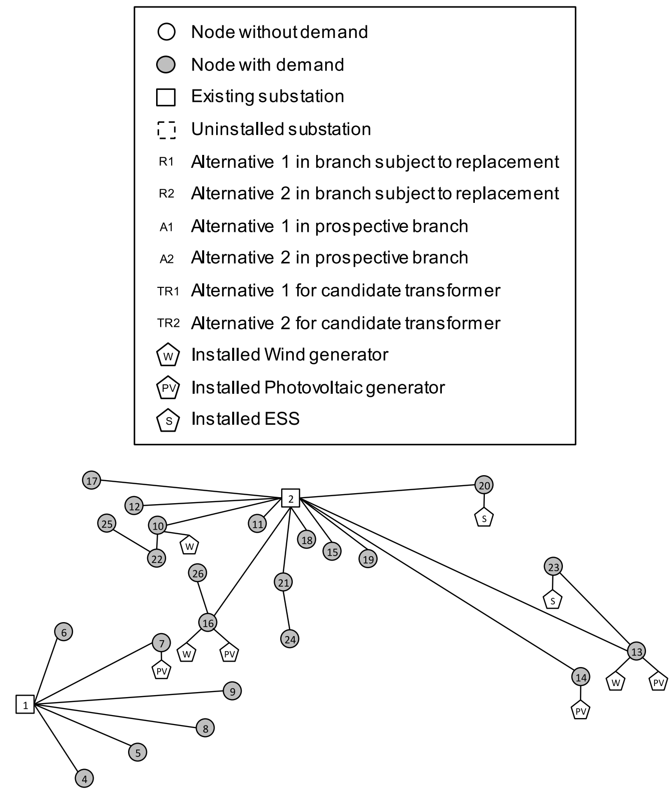

Fig. 6. One-line diagram of the La Graciosa distribution network expansion with DRR and ESS.

allowing for a higher penetration of DG and accounting for wind and PV imbalances. The model results in a total payment of the demand lower than in the previous case, where DR has not been considered. Storage units are managed to increase the expected benefits of the generation and distribution company, accelerating the penetration of renewable technologies.

The final situation of the distribution system of La Graciosa is presented in Fig. 6.

It is worth mentioning how distribution network expansion planning is highly dependent on the introduction of DR and ESS in the expansion planning model.

The simulations have been implemented on a Dell PowerEdge R910X64 with four Intel Xeon E7520 processors at 8 GHz and 32 GB of RAM using CPLEX 12.6 [9] under GAMS 24.2.3 [10]. The stopping criterion for the branch-and-cut algorithm of CPLEX used in the proposed model is based on an optimality gap equal to 0.5%. Under this stopping criterion, the attainment of each solution took 20 h on average. The results indicate the practical applicability of the proposed long-term distribution network expansion planning algorithm, especially considering the time frame of the problem addressed. The computational time is highly dependent on the optimality gap to ensure accuracy of the solution and the number of binary variables which are dependent on the storage and demand response constraints, as well as the considered

TABLE XIII
COMPUTATIONAL COMPLEXITY OF THE PROPOSED ALGORITHM

# of binary variables	$6{*}K^i{*}T + K^i{*}T{*}LL{*}W + K^i{*}B{*}T{*}LL{*}W$
# of continuous variables	$5{*}T + 2{*}T + LL{*}W + 12{*}K^i{*}T{*}LL{*}W + 3{*}B{*}T{*}LL{*}W$
# of constraints	$7{*}T + 6{*}\Omega^{ST}T{*}LL{*}W + 12{*}K^i{*}T{*}LL{*}W + 12{*}\gamma^l{*}T{*}LL{*}W + 6{*}(ERF{+}NRF){*}T{*}LL{*}W + 6{*}(NAF){*}T{*}LL{*}W + 4{*}\Omega^p{*}T{*}LL{*}W$

network (replaceable lines and location of technologies). For bigger systems, the number of replaceable lines and location of new technologies can be reduced or fixed (which is a reasonable assumption) in order to make the problem tractable. Table XIII summarizes the computational complexity for our MILP model.

III. METRICS FOR EXPANSION PLANNING

In order to analyse future investments in generation units and distribution assets to be undertaken by the owner and operator of the system, a set of metrics showing the welfare achieved by the different stakeholders has been implemented following the approach proposed in [11]. For every considered scenario the overall welfare is studied from the perspective of its estimated net profit over a period of several years. Financial risk assessment plays a crucial role in such reviews because it is the key to obtaining adequate financing. Values for costs and benefits for both, generation and distribution companies and consumers are presented in Table XIV. The results present the costs and benefits for all the considered case studies:

- Base case where neither DR nor ESS are considered in generation and distribution expansion planning
- Integration of DR in generation and distribution expansion planning
- Integration of ESS in generation and distribution expansion planning
- Integration of both, DR and ESS in generation and distribution expansion planning

Table XIV summarizes the numerical results obtained in the four considered case studies, including the costs and benefits for the planner and the consumers. The benefits for the planner are obtained subtracting the generation and distribution (operation and investment) costs from the payments received from the consumers. The benefits for the consumers are obtained comparing the payments in the considered scenario with those corresponding to the base case.

DR can be defined as an incentive payment to reduce electricity consumption in times of high energy prices, increasing the electricity consumption at times of low prices. Any consumption shifting from high energy prices to low energy prices will reduce benefits for generation and distribution companies, while increasing the benefits for consumers. Additionally, the introduction of DR in the problem results in lower costs for generation and distribution investment, reducing the overall costs from k€6303.8 to k€6047.1. The introduction of DR in the model formulation results in a lower payment for the consumers, being reduced from k€10653.5 to k€10538.6.

TABLE XIV
COSTS AND BENEFITS FOR GENERATION, DISTRIBUTION AND CONSUMER [THOUSANDS OF €]

	Base Case	***DR***	***ESS***	***DR and ESS***
Benefits for generation & distribution company	4349.7	4491.5	4471.4	4551.5
Costs for generation & distribution company	6303.8	6047.1	6293.6	6155.7
Benefits for consumers	0	114.9	-111.5	-53.7
Costs for consumers	10653.5	10538.6	10765	10707.2

Energy storage can benefit utilities allowing for distribution upgrade deferrals speeding up the integration of renewable technologies. In the present formulation, ESS are controlled by generation companies and, therefore, its introduction increases the benefits for generation and distribution planning. The costs for the company are similar (from k€6303.8 to k€6293.6) over the considered time horizon, while the benefits increase (from k€4349.7 to k€4471.4).

The joint consideration of DR and ESS in the model results in an increase of the benefits for the generation and distribution company (from k€4349.7 to k€4551.5), while the benefit the consumers experienced reduces by k€53.7 over the considered time horizon. When compared to the case where only ESS is considered, the introduction of DR results in an increase of the benefit of the consumers of k€57.8. The presented results outline that an adequate expansion planning requires the integration of DR and ESS in the planning process, since some overinvestments may be averted. However, it can be observed how demand is highly penalized when ESS is considered in the expansion planning model, increasing significantly its payment.

The metric showing the change in the aggregate social welfare as a result of the integration of price-dependent resources such as DR and ESS in the generation and distribution expansion planning is given by the following parameter:

$$\mu_1 = \frac{SW^* - SW^0}{INV^*} \tag{1}$$

where SW^* represents the aggregate social welfare including the benefits for the generation and distribution planner and the benefits for the consumers when considering DR and/or ESS in the model formulation, and SW^0 represents the base case. SW^0 is obtained by solving the expansion planning algorithm for the case study without considering DR or ESS. Investment costs to be undertaken by the generation and distribution planner are represented by INV^*.

The previous ratio, μ_1, is a useful metric for the system as a whole, accounting for the benefits obtained by generation, distribution and demand aggregators. Policy makers may be interested in this ratio when deciding the promotion of the different solutions. However, it could be objected by generators, distributors and demand aggregators that their particular improvements are not clearly identified in this metric. Two additional metrics, μ_2 and μ_3, have been defined, one for the

TABLE XV
OVERALL METRICS

Case study	μ_1	μ_2	μ_3
DR	0.04	0.02	0.02
ESS	0.00	0.02	-0.02
ESS and DR	0.02	0.03	-0.01

generation and distribution planner and the other for demand aggregators.

The metric available to the distribution and generation planner is represented by the change in their surplus with respect to the base case situation (without DR and ESS), when incorporating DR and/or ESS:

$$\mu_2 = \frac{BD^* - BD^0}{INV^*} \tag{2}$$

where BD^* represents the aggregate benefit of the distribution and generation planner, understood as the difference between incomes (payments) from consumers and total costs of the considered investment plan. BD^0 is obtained by solving the expansion planning algorithm for the case study without considering DR or ESS (base case).

Likewise, demand aggregators can measure the increase of their benefit as a consequence of the deployment of DR. This metric is defined as:

$$\mu_3 = \frac{BC^* - BC^0}{INV^*} \tag{3}$$

where BC^* represents the aggregate benefit of the consumers, understood as the reduction in the payment when shifting their consumption to lower-price hours. Table XV summarizes the considered metrics outlining how the integration of DR and ESS impacts the surpluses of consumers and the generation and distribution planner.

The μ_1 metric represents the change in the aggregate social welfare as a consequence of the integration of DR and/or ESS in the planning model. The introduction of DR increases net social welfare and the benefits of the generation and distribution company, also increasing the benefits for the consumers. This result is in line with the expected impact of DR, since this reflects the added value consumers may attain from its intrinsic flexibility. Considering the effect of ESS in distribution expansion planning, benefit of the generation and distribution company is increased, while the consumers are penalized. The impact of DR in the joint effect of DR and ESS in the expansion planning for the considered model is not sufficient to counteract the impact of ESS. However, NSB is increased when considering the joint effect of both technologies, reducing the payment of the demand and the overall investment when compared to the case where only ESS is considered.

The problem has been enhanced including a sensitivity analysis considering different demand response elasticities ranging from 0% to 2% between day and night periods and from 0% to 4% between the demand levels (within the defined day or night periods) as depicted in Fig. 7. A sensitivity analysis considering different operational costs for the ESS has been included as depicted in Fig. 8. Increasing the elasticity of the

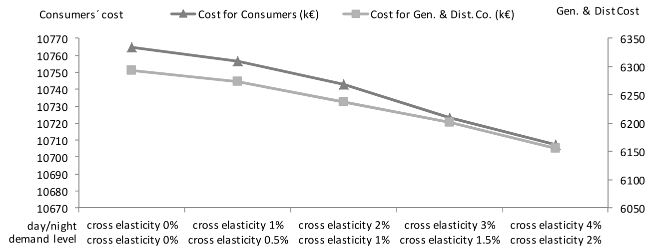

Fig. 7. Sensitivity analysis for demand response elasticity.

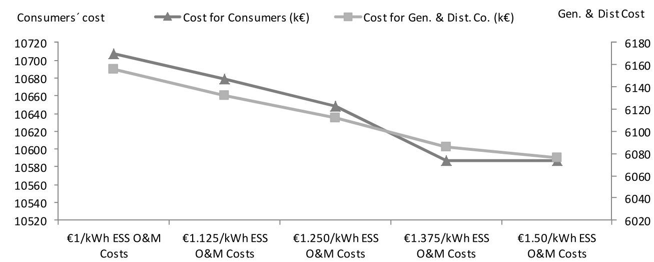

Fig. 8. Sensitivity analysis for ESS O&M costs.

demand, overall payment for the final consumers is reduced, while costs faced by the generation and distribution company are also reduced. An increase on the O&M costs for the ESS leads to a lower investment in this technology, reducing therefore the overall investment costs for the central planner and the payment for the consumers, in line with the results previously presented in this section. The reduction on the investment in ESS minimizes the effect of the incentive to the central planner to shift substation energy demand (and therefore substation energy prices as depicted in Fig. 2). The stopping criterion for the branch-and-cut algorithm of CPLEX used in the sensitivity analysis relies on an optimality gap equal to 0.25%.

IV. CONCLUSION

In the second part of this two-paper series, numerical results for the electric power system of La Graciosa in the Canary Islands are presented, accounting for the impact of DR and ESS in joint generation and distribution expansion planning. As presented in the study, the inclusion of DR in the formulation of the problem reduces the payment of consumers, who modify their consumption patterns depending on energy prices.

The present paper demonstrates how DR and/or ESS can contribute to adequately accommodate renewable generation in a joint distribution and generation expansion planning problem, increasing the volume of RES penetration in the distribution network. Additionally, the presence of ESS slightly accelerates the required network reinforcement from stage three to stage two.

The modelling of uncertainty in a distribution system for each single load block is based on the load, wind and solar irradiation curves. Hourly historical demand data are arranged from higher to lower values keeping the correlation between the different hourly data of wind and PV productions. The load duration curve is approximated using demand blocks.

TABLE XVI
BRANCH LENGTHS (m)

Branch i	Branch j	$\ell_{i,j}$	Branch i	Branch j	$\ell_{i,j}$	Branch i	Branch j	$\ell_{i,j}$
1	4	200	2	17	230	10	22	50
1	5	185	2	18	30	11	26	112
1	6	90	2	19	160	12	25	43
1	7	190	2	20	240	13	23	270
1	8	260	2	21	150	16	24	155
1	9	250	3	13	220	16	26	90
2	10	200	3	20	290	17	25	66
2	11	20	3	23	120	19	24	220
2	12	220	7	25	53	20	23	170
2	13	500	8	22	82	21	24	93
2	14	550	9	22	64	22	25	85
2	15	50	9	25	46	22	26	104
2	16	220						

TABLE XVII
DATA FOR EXISTING FIXED FEEDERS

$\bar{F}_{i,j}^{EFF}$ **(MVA)**	$Z_{i,j}^{EFF}$ **(Ω/km)**	$R_{i,j}^{EFF}$ **(Ω/km)**
1	0.5568	0.4070

The corresponding scenario-based deterministic equivalent is formulated as a mixed-integer nonlinear program. The subsequent use of some well-known linearization schemes yields a mixed-integer linear program suitable for efficient off-the-shelf software.

It can be outlined that an adequate expansion planning requires the integration of DR and ESS in the planning process, since some overinvestments may be averted. Operation and investment costs, as well as payment of the demand for the considered models outline the potential of DR to effectively reduce payments of the demand in the long-term by approximately 2%. Additionally, the impact of ESS in the generation and distribution expansion planning has been exhaustively investigated, showing the potential benefits for the central planner.

In order to analyze future investments in generation units and distribution assets to be undertaken by the owner and operator of the system, a set of metrics showing the welfare modification achieved by the different stakeholders has been implemented. These should help regulators and key industry stakeholders when evaluating DR and ESS in future resource plans.

APPENDIX

LA GRACIOSA NETWORK DATA

Data regarding branch lengths are listed in Table XVI.

Table XVII shows data for existing fixed feeders. These data comprise maximum current flow, impedance, and resistance.

Table XVIII shows data for candidate feeders in branches subject to replacement. Table XIX shows data for candidate feeders in non-existing branches.

TABLE XVIII
DATA FOR CANDIDATE REPLACEMENT CONDUCTORS

Alternative 1				Alternative 2			
$\bar{F}_{i,j1}^{NRF}$ (MVA)	$Z_{i,j1}^{NRF}$ (Ω/km)	$R_{i,j1}^{NRF}$ (Ω/km)	$C_{i,j1}^{I,NRF}$ (10^3 €/km)	$\bar{F}_{i,j2}^{NRF}$ (MVA)	$Z_{i,j2}^{NRF}$ (Ω/km)	$R_{i,j2}^{NRF}$ (Ω/km)	$C_{i,j2}^{I,NRF}$ (10^3 €/km)
0.3	0.2326	0.2100	30.2	0.5	0.1920	0.1227	35.3

TABLE XIX
DATA FOR CANDIDATE CONDUCTORS IN NON-EXISTING BRANCHES

Alternative 1				Alternative 2			
$\bar{F}_{i,j1}^{NAF}$ (MVA)	$Z_{i,j1}^{NAF}$ (Ω/km)	R_{ij1}^{NAF} (Ω/km)	$C_{ij1}^{I,NRF}$ (10^3 €/km)	$\bar{F}_{ij1}^{NAF}$ (MVA)	Z_{ij1}^{NAF} (Ω/km)	R_{ij2}^{NAF} (Ω/km)	$C_{ij2}^{I,NRF}$ (10^3 €/km)
0.1	0.5568	0.4070	32.3	0.3	0.2326	0.2100	38.7

TABLE XX
DATA FOR TRANSFORMERS

Alternative 1				Alternative 2			
$\bar{G}_{i1}^{NT}$ (MVA)	R_{i1}^{NT} (Ω)	$C_{i1}^{M,NT}$ (k€)	$C_{i1}^{I,NT}$ (k€)	$\bar{G}_{i2}^{NT}$ (MVA)	R_{i2}^{NT} (Ω)	$C_{i2}^{M,NT}$ (k€)	$C_{i2}^{I,NT}$ (k€)
0.6	0.16	0.2	25	0.8	0.13	0.3	32
0.6	0.16	0.2	25	0.8	0.13	0.3	32
0.6	0.16	0.2	25	0.8	0.13	0.3	32

TABLE XXI
DATA FOR CANDIDATE DG UNITS

Altern. k	$\bar{G}_k^W$ (MVA)	$C_k^{I,W}$ (€/kW)	$C_k^{E,W}$ (€/kWh)	$\bar{G}_k^{\Theta}$ (MVA)	$C_k^{I\Theta}$ (€/kW)	$C_k^{E,\Theta}$ (€/kWh)
1	0.02	1010	5	0.024	500	4

TABLE XXII
DATA FOR CANDIDATE STORAGE UNITS

Stage **t**	$\bar{G}^{st}$ **(MVA)**	$C^{I,st,t}$ **(€/kW)**	$C^{st,prod}$ **(€/kWh)**
1	0.02	2000	1
2	0.02	1900	1
3	0.02	1800	1
4	0.02	1700	1
5	0.02	1600	1

Table XX shows data for existing transformers, candidate transformers to install, and the cost of expanding or building substations.

The economic and technical features of the candidate DG units are presented in Table XXI. For simplicity reasons, only one alternative has been considered for wind and photovoltaic generation units. Data corresponding to the considered storage are presented in Table XXII. The model includes variable storage prices for each stage representing the learning curve of the technology over the time.

Tables XXIII and XXIV present the data considered for the reference substation prices defined in Fig. 2.

TABLE XXIII
UPPER AND LOWER LIMITS OF SUBSTATION STEP B

b	L_b^{min}	L_b^{max}
1	0.0	0.15
2	0.0	0.03
3	0.0	0.03
4	0.0	0.06
5	0.0	0.26
6	0.0	0.47

TABLE XXIV
INCREMENTAL COST ASSOCIATED TO THE SUBSTATION LOAD LEVEL B

b	C_b
1	150
2	50
3	20
4	20
5	20
6	20

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