Influence of Distributed Storage Systems and Network Switching/Reinforcement on RES-based DG Integration Level

M.R.M. Cruz, D.Z. Fitiwi, S.F. Santos, J.P.S. Catalão
INESC TEC and FEUP, Porto, C-MAST/UBI, Covilha, and INESC-ID/IST, Lisbon, PORTUGAL
marco.r.m.cruz@gmail.com; dzf@ubi.pt; sdfsantos@gmail.com; catalao@fe.up.pt

***Abstract*—Nowadays, there is a global consensus that integrating renewable energy sources (RES) is highly needed to meet an increasing demand for electricity and reduce the overall carbon footprint of power production. Framed in this context, the coordination of RES integration with distributed energy storage systems (DESS), along with the network's switching capability and/or network reinforcement, is expected to significantly improve system flexibility, thereby increasing chances of accommodating large-scale RES power. This paper presents an innovative method to quantify the impacts of network switching and/or reinforcement as well as installing DESSs on the level of renewable power integrated in the system. To carry out this analysis, a dynamic and multi-objective stochastic mixed integer linear programming (S-MILP) model is developed, which jointly takes into account the optimal RES-based DGs and DESS integration in coordination with distribution network reinforcement and/or switching. A standard distribution network system is used as a case study. Numerical results show the capability of DESSs integration in dramatically increasing the level of renewable DGs integrated in the system. Although case-dependent, the impact of network switching on RES power integration is not significant.**

***Index Terms*—Distributed energy storage systems, distributed generation, network reinforcement, network switching, RESs.**

I. NOMENCLATURE

A. Sets/Indices

i/Ω^i	Index/set of buses
$g/\Omega^g/\Omega^{DG}$	Index/set of generators/DGs
k/Ω^k	Index/set of branches
s/Ω^s	Index/set of yearly scenarios
t/Ω^t	Index/set of planning stages
w/Ω^w	Index/set of hourly snapshots
$\varsigma/\Omega^\varsigma$	Index/set of substations

B. Parameters

$ER_g^N, ER_g^E, ER_\varsigma^{SS}$	Emission rates of new and existing DGs, and energy purchased, respectively (tCO_2e/MWh)
$IC_{g,i}, IC_k, IC_{es,i}$	Investment cost of DG, line and energy storage, respectively (M€)
$LT_g, LT_k, LT_{tr}, LT_{es}$	Lifetimes of DG, distribution line, transformer and energy storage system, respectively (years)
MC_{es}, MC_{tr}	Maintenance cost of storage/trafo per year (M€)
MC_g^N, MC_g^E	Maintenance costs of new and existing DGs (M€/yr)
MC_k^N, MC_k^E	Maintenance cost of new and existing line (M€/yr)
$OC_{g,i,s,w,t}^N, OC_{g,i,s,w,t}^E$	Operation cost of unit energy production by new and existing DGs (€/MWh)
$\lambda_{s,w,t}^{CO_2e}$	Price of emissions (€/tons of CO_2 equivalent)
$\lambda_{s,w,t}^{\varsigma}$	Price of electricity purchased (€/MWh)
ρ_s, π_w	Probability of yearly scenario *s* and weight (in hours) of hourly snapshot group *w*
$\upsilon_{s,w,t}$	Penalty for unserved power (€/MW)
$\eta_{ch,es}$	Charging efficiency (%)
μ_{es}	Scaling factor (%)

C. Variables

$\delta_{i,s,w,t}$	Unserved power at node *i* (MW)
$D_{s,w,t}^i$	Active power demand at node *i* (MW)
$P_{g,i,s,w,t}^N, P_{g,i,s,w,t}^E$	Power produced by new and existing DGs (MW)
$P_{\varsigma,s,w,t}^{SS}$	Active power imported from grid (MW)
$u_{g,i,t}, u_{k,t}$	Utilization variables of existing DG and lines
$x_{g,i,t},\ x_{es,i,t}, x_{k,t}$	Investment variables for DG, storage systems and distribution lines, respectively
$\varphi_{k,s,w,t}$	Losses associated to each feeder (MW)
$E_{es,i,s,w,t}$	Reservoir level of ESS (MWh)
$I_{es,i,s,w,t}^{dch}, I_{es,i,s,w,t}^{ch}$	Discharging/charging indicator variables
$P_{es,i,s,w,t}^{dch}, P_{es,i,s,w,t}^{ch}$	Discharged/charged power (MW)
$x_{tr,ss,t}$	Transformer investment variable

D. Functions (all units are in M€)

EC_t^{SS}	Expected cost of energy purchased from upstream
$ENSC_t$	Expected cost of unserved power
$EmiC_t^{DG}$	Expected emission cost of DG power production
$EmiC_t^N, EmiC_t^E$	Expected emission cost of power production using new and existing DGs, respectively
$EmiC_t^{SS}$	Expected emission cost of purchased power
$InvC_t^{DNS}, MntC_t^{DNS}$	NPV investment/maintenance cost of DNS components
$InvC_t^{DG}, MntC_t^{DG}, EC_t^{DG}$	NPV investment/maintenance/expected energy cost of DGs, respectively
$InvC_t^{LN}, MntC_t^{LN}$	NPV investment/maintenance cost of a line
$InvC_t^{ES}, MntC_t^{ES}$	NPV investment/maintenance cost of ESS

II. INTRODUCTION

A. Motivation and Aims

The issue of integrating renewable distributed generations (DGs) in power distributions systems is becoming very critical because of technical, economic and environmental reasons. Nowadays, there is a global consensus that integrating renewable energy sources—RESs, is highly needed to meet an increasing demand for electricity and reduce the overall carbon footprint of energy production. However, large-scale integration of RES-based DGs often poses a number of technical challenges in the system from the stability, reliability and power quality perspective. This is because integrating RESs introduces significant operational variability and uncertainty to the distribution system, making operation, planning and control rather complicated. Hence, such a high level integration effort is likely to be supported by certain smart-grid technologies and concepts that have the capability to enhance the flexibility of the entire distribution systems. Framed in this context, the integration of distributed energy storage systems (DESSs) jointly with DGs, along with the network's switching capability and/or network reinforcement, significantly improves the flexibility of the system, thereby increasing chances of accommodating large-scale RES power.

This paper presents a method to quantify the influences of simultaneous consideration of investments in DESSs as well as network switching and/or reinforcement on the level of renewable power integrated in the system. To carry out this analysis, a stochastic mixed integer linear programming (S-MILP) model is developed which takes account of distribution network reinforcement and/or switching in coordination with investments in RES-based DGs and DESS technologies.

B. Literature Review

RESs make a crucial part of the solution for environmental sustainability; hence, they will play an important role in power systems [1]. The integration of RESs should, in principle, reduce the risk of fuel price volatility and geopolitical pressures and ensure that these do not pose a significant impact on the overall public welfare [2], [3]. However, large-scale penetration of RESs will necessarily involve a process of adapting and changing the existing infrastructure because of their intrinsic characteristics, such as intermittency and variability. The growing need for intermittent RESs, in conjunction with the electrical mix changes in the long-term, will probably affect the distribution and transmission systems. In this context, a change in power generation options, resulting from a high contribution of RESs, may require network grid updates. Regulatory agencies are heavily committed to increase RES integration, not only due to environmental but also technical and economic reasons [4].

The main challenge with most of RESs is their inherent variability and uncertainty, making operation, control and planning very complicated. DG penetration increases the variation of voltage and current in the network. Hence, increasing DG penetration may have a negative or positive impact depending on various factors such as the size of the system and the loads type, requiring modeling and simulations to assess its impact [5]. If not properly planned, this may lead to an uncertain increase in the feeders' power flows, resulting in network congestion and increased losses in the network. However, the integration of DESS with RESs have become one of the most viable solutions to facilitate the increased penetration of DG resources [4], [6]. Energy storage systems level the mismatch between renewable power generation and demand [6]. This is because these devices store energy during periods of low electricity demand (price) or high RES power production, and the release it during periods of peak demand and low RES production [7]. Therefore, in addition to their technical support to the system, ESSs bring substantial benefits for end-users and DG owners through reliability and power quality improvement as well as cost reduction [8]. Besides, ESSs are being developed and applied in power grids to cope with a number of issues such as smoothing the energy output from RESs, improving the stability of the electrical system, etc. [9]. ESSs also increase savings during peak hours and minimize the impact of intermittent generation sources, leading to a more efficient management of the integrated system.

Electrical distribution systems are interconnected by switches but predominantly operated radially. These switches are often used for emergency purposes such as to evade load curtailment during fault cases. However, the system can be reconfigured to find the best topology that minimizes power losses in the system and improve operational performance, in general [10], [11]. Ref. [12] discusses distribution network reconfiguration for minimizing losses in the presence of variable energy sources. Authors in [13] have investigated the impact of load variability on network reconfiguration outcome. In [14], [15], authors have studied distribution system reconfiguration with the aim of reducing energy losses under normal conditions. As the network topology can be adjusted by the change of switches state in the lines (normally opened/closed), the optimal management of the entire system has to find the optimal network configuration, allowing greater network flexibility [16], which may in turn allow large-scale RES integration. The work in [17] considers dynamic reconfiguration with a possibility of remotely controlling switches in an active and centralized management framework, with the aim of removing network congestion in real time.

The present work presents a qualitative and quantitative analysis regarding the impact of joint integration ESSs, network switching (reconfiguration) and reinforcement on the level of DG integration (particularly, focusing on RESs). For carrying out this analysis, a multi-objective S-MILP model is developed considering the operational variability and uncertainty of variable power resources.

C. Contributions and Paper Organization

The main contributions of this work are twofold:

- A multi-stage and stochastic optimization model, which considers simultaneous integration of DESSs and variable generation sources as well as network switching/investments;
- A thorough analysis related to the influence of network flexibility (switching capability, investments) and/or DESS installations made in coordination with investments in variable generation sources on the RES integration level, system cost and losses.

The rest is organized as follows. Section III presents a brief description of the developed mathematical model. Numerical results are discussed in Section IV. The final section concludes this paper.

III. MODEL FORMULATION

The dynamic and multi-objective S-MILP optimization model developed here is described as follows.

A. Objective Function

The problem is formulated as a multi-objective stochastic MILP with an objective of overall cost minimization as in (1). The objective function in (1) is composed of Net Present Value (NPV) of five cost terms each weighted by a certain relevance factor $\gamma_j; \forall j \in \{1,2,\ldots,5\}$.

The first term in (1), $TInvC$, represents the total investment costs under the assumption of perpetual planning horizon [18]. In other words, "the investment cost is amortized in annual installments throughout the lifetime of the installed component", as is done in [19].

Here, the total investment cost is the sum of investment costs of DGs, distribution network system (DNS) components (feeders and transformers) and ESSs, as in (2). And, this cost is computed as in (7)-(9). The second term, TMC, in (1) denotes the total maintenance costs, which is given by the sum of maintenance costs of new and existing DGs as well as that of DNS components and ESSs at each stage and the corresponding costs incurred after the last planning stage, as in (3). Note that the latter depend on the maintenance costs of the last planning stage according a perpetual planning horizon. These maintenance costs are computed according to Eqs. (10)-(12).

The third term TEC in (1) refers to the total cost of energy in the system, which is the sum of the cost of power produced by new and existing DGs, supplied by ESSs and purchased from upstream at each stage as in (4). Eq. (4) also includes the total energy costs incurred after the last planning stage under the assumption of perpetual planning horizon. These depend on the energy costs of the last planning stage. The detailed mathematical expressions for computing the cost of DG power produced and ESS power supplied as well as that of purchased power are given in (13), (14) and (15), respectively.

The fourth term $TENSC$ represents the total cost of unserved power in the system, given as in (5). And, this is computed using Eq. (16). The last term $TEmiC$ gathers the total emission costs in the system, given by the sum of emission costs for the existing and new DGs (17)-(19) as well that of purchased power (20).

$$Minimize\ TC = \gamma_1 * TInvC + \gamma_2 * TMC + \gamma_3 * TEC + \gamma_4 * TENSC + \gamma_5 * TEmiC \quad (1)$$

$$TInvC = \underbrace{\sum_{t\epsilon\Omega^t}(1+r)^{-t}(InvC_t^{DG} + InvC_t^{DNS} + InvC_t^{ES})/r}_{NPV\ of\ investment\ cost} \quad (2)$$

$$TMC = \underbrace{\sum_{t\epsilon\Omega^t}(1+r)^{-t}\ (MntC_t^{DG} + MntC_t^{DNS} + MntC_t^{ES})}_{NPV\ of\ maintenance\ costs} + \underbrace{(1+r)^{-T}(MntC_T^{DG} + MntC_T^{DNS} + MntC_T^{ES})/r}_{NPV\ maintenance\ costs\ incured\ after\ stage\ T} \quad (3)$$

$$TEC = \underbrace{\sum_{t\epsilon\Omega^t}(1+r)^{-t}\ (EC_t^{DG} + EC_t^{SS} + EC_t^{ES})}_{NPV\ of\ operation\ costs} + \underbrace{(1+r)^{-T}(EC_T^{DG} + EC_T^{SS} + EC_T^{ES})/r}_{NPV\ operation\ costs\ incured\ after\ stage\ T} \quad (4)$$

$$TENSC = \underbrace{\sum_{t\epsilon\Omega^t}(1+r)^{-t}\ ENSC_t}_{NPV\ of\ reliability\ costs} + \underbrace{(1+r)^{-T}ENSC_T/r}_{NPV\ reliability\ costs\ incured\ after\ stage\ T} \quad (5)$$

$$TEmiC = \underbrace{\sum_{t\epsilon\Omega^t}(1+r)^{-t}\ (EmiC_t^{DG} + EmiC_t^{SS})}_{NPV\ emission\ costs} + \underbrace{(1+r)^{-T}(EmiC_T^{DG} + EmiC_T^{SS})/r}_{NPV\ emission\ costs\ incured\ after\ stage\ T} \quad (6)$$

$$InvC_t^{DG} = \sum_{g\epsilon\Omega^g}\sum_{i\epsilon\Omega^i}\frac{r(1+r)^{LT_g}}{(1+r)^{LT_g}-1}IC_{g,i}(x_{g,i,t} - x_{g,i,t-1})\ ; where\ x_{g,i,0} = 0 \quad (7)$$

$$InvC_t^{DNS} = \sum_{k\epsilon\Omega^\ell}\frac{r(1+r)^{LT_k}}{(1+r)^{LT_k}-1}IC_k(x_{k,t} - x_{k,t-1}) + \sum_{ss\epsilon\Omega^{ss}}\sum_{tr\epsilon\Omega^{tr}}\frac{i(1+i)^{LT_{tr}}}{(1+i)^{LT_{tr}}-1}IC_{tr}(x_{tr,ss,t} - x_{tr,ss,t-1})\ ;\ where\ x_{k,0} = 0\ and\ x_{tr,ss,0=0} \quad (8)$$

$$InvC_t^{ES} = \sum_{c\epsilon\Omega^c}\sum_{i\epsilon\Omega^i}\frac{r(1+r)^{LT_{ess}}}{(1+r)^{LT_{es}}-1}IC_c(x_{es,i,t} - x_{es,i,t-1})\ ; where\ x_{es,i,0} = 0 \quad (9)$$

$$MntC_t^{DG} = \sum_{g\epsilon\Omega^g}\sum_{i\epsilon\Omega^i}MC_g^N\, x_{g,i,t} + \sum_{g\epsilon\Omega^g}\sum_{i\epsilon\Omega^i}MC_g^E\, u_{g,i,t} \quad (10)$$

$$MntC_t^{DNS} = \sum_{k\epsilon\Omega^{e\ell}}MC_k^E\, u_{k,t} + \sum_{k\epsilon\Omega^{n\ell}}MC_k^N x_{k,t} + \sum_{tr\epsilon\Omega^{E\_tr}}MC_{tr}^E\, u_{tr,ss,t} + \sum_{tr\epsilon\Omega^{N\_tr}}MC_k^N x_{tr,ss,t} \quad (11)$$

$$MntC_t^{ES} = \sum_{c\epsilon\Omega^c}\sum_{i\epsilon\Omega^i}MC_{es}x_{es,i,t} \quad (12)$$

$$EC_t^{DG} = \sum_{s\epsilon\Omega^s}\rho_s\sum_{w\epsilon\Omega^w}\pi_w\sum_{g\epsilon\Omega^g}\sum_{i\epsilon\Omega^i}(OC_{g,i,s,w,t}^N P_{g,i,s,w,t}^N + OC_{g,i,s,w,t}^E\, P_{g,i,s,w,t}^E) \quad (13)$$

$$EC_t^{ES} = \sum_{s\epsilon\Omega^s}\rho_s\sum_{w\epsilon\Omega^w}\pi_w\sum_{es\epsilon\Omega^{es}}\lambda_{s,w,t}^{es}P_{es,i,s,w,t}^{dch} \quad (14)$$

$$EC_t^{SS} = \sum_{s\epsilon\Omega^s}\rho_s\sum_{w\epsilon\Omega^w}\pi_w\sum_{\varsigma\epsilon\Omega^\varsigma}\lambda_{s,w,t}^{\varsigma}P_{\varsigma,s,w,t}^{SS} \quad (15)$$

$$ENSC_t = \sum_{s\epsilon\Omega^s}\rho_s\sum_{w\epsilon\Omega^w}\sum_{i\epsilon\Omega^i}\pi_w \upsilon_{s,w,t}\delta_{i,s,w,t} \quad (16)$$

$$EmiC_t^{DG} = EmiC_t^N + EmiC_t^E \quad (17)$$

$$EmiC_t^N = \sum_{s\epsilon\Omega^s}\rho_s\sum_{w\epsilon\Omega^w}\pi_w\sum_{g\epsilon\Omega^g}\sum_{i\epsilon\Omega^i}\lambda_{s,w,t}^{CO_2e}ER_g^N P_{g,i,s,w,t}^N \quad (18)$$

$$EmiC_t^E = \sum_{s\epsilon\Omega^s}\rho_s\sum_{w\epsilon\Omega^w}\pi_w\sum_{g\epsilon\Omega^g}\sum_{i\epsilon\Omega^i}\lambda_{s,w,t}^{CO_2e}ER_g^E P_{g,i,s,w,t}^E \quad (19)$$

$$EmiC_t^{SS} = \sum_{s\epsilon\Omega^s}\rho_s\sum_{w\epsilon\Omega^w}\pi_w\sum_{\varsigma\epsilon\Omega^\varsigma}\sum_{i\epsilon\Omega^i}\lambda_{s,w,t}^{CO_2e}ER_\varsigma^{SS}P_{\varsigma,s,w,t}^{SS} \quad (20)$$

B. Constraints

The active power balance at each node is enforced by:

$$\sum_{g\epsilon\Omega^{DG}}(P_{g,i,s,w,t}^E + P_{g,i,s,w,t}^N) + \sum_{es\epsilon\Omega^{es}}(P_{es,i,s,w,t}^{dch} - P_{es,i,s,w,t}^{ch}) + P_{\varsigma,s,w,t}^{SS} + \sum_{in,k\epsilon i}P_{k,s,w,t} - \sum_{out,k\epsilon i}P_{k,s,w,t} + \delta_{i,s,w,t} = \sum_{in,k\epsilon i}0.5\varphi_{k,s,w,t} + \sum_{out,k\epsilon i}0.5\varphi_{k,s,w,t} + D_{s,w,t}^i\ ;\ \forall\varsigma, \forall\varsigma\epsilon i \quad (21)$$

Eq. (21) denotes that the sum of all incoming flows should be equal to the sum of all outgoing flows at each node. Note that losses in every feeder are considered as "virtual loads" which are equally distributed between the nodes connecting the feeder. Note that losses are a quadratic function of flows (not shown here). Hence, they are linearized using first order approximation, as in [19].

For the sake of simplicity, a generic ESS is employed here. And, this is modeled by the set of constraints in (22)-(28). Eqs. (22) and (23) represent the bounds of power capacity of the ESS while being charged and discharged, respectively. Inequality (24) prevents simultaneous charging and discharging operation of ESS at the same operational time w. The amount of stored energy within the ESS reservoir at a given operational time w as a function of the energy stored until $w-1$ is given by (25). The maximum and minimum levels of storages in the operational time w are also considered through inequality (26). Eq. (27) shows the initial level of stored energy in the ESS as a function of its maximum reservoir capacity. In a multi-stage planning approach, Eq. (28) ensures that the initial level of energy in the ESS at a given year is equal to the final level of energy in the ESS in the preceding year. Here, η_{es}^{dch} is assumed to be $1/\eta_{es}^{ch}$.

$$0 \le P_{es,i,s,w,t}^{ch} \le I_{es,i,s,w,t}^{ch}x_{es,i,t}P_{es,i}^{ch,max} \quad (22)$$

$$0 \le P_{es,i,s,w,t}^{dch} \le I_{es,i,s,w,t}^{ch}x_{es,i,t}P_{es,i}^{ch,max} \quad (23)$$

$$I_{es,i,s,w,t}^{ch} + I_{es,i,s,w,t}^{dch} \le 1 \quad (24)$$

$$E_{es,i,s,w,t} = E_{es,i,s,w-1,t} + \eta_{ch,es}P_{es,i,s,w,t}^{ch} - \eta_{dch,es}P_{es,i,s,w,t}^{dch} \quad (25)$$

$$E_{es,i}^{min}x_{es,i,t} \le E_{es,i,s,w,t} \le x_{es,i,t}E_{es,i}^{max} \quad (26)$$

$$E_{es,i,s,w_0,T1} = \mu_{es}x_{es,i,T1}E_{es,i}^{max} \quad (27)$$

$$E_{es,i,s,w_1,t+1} = E_{es,i,s,W,t} \quad (28)$$

Notice that inequalities (22) and (23) involve products of charging/discharging indicator variables and investment variable. In order to linearize this, new continuous positive variables $z_{es,i,s,w,t}^{ch}$, and $z_{es,i,s,w,t}^{dch}$, which replaces the bilinear products in each constraint, is introduced such that the set of linear constraints in (29) and (30) hold. For instance, the product $I_{es,i,s,w,t}^{dch}x_{es,i,t}$ is replaced by the positive variable $z_{es,i,s,w,t}^{dch}$. Then, the bilinear product is decoupled by introducing the set of constraints in (29) [20].

$$z_{es,i,s,w,t}^{dch} \le x_{es}^{max}I_{es,i,s,w,t}^{dch}\ ;\ z_{es,i,s,w,t}^{dch} \le x_{es,i,t}\ ; z_{es,i,s,w,t}^{dch} \ge x_{es,i,t} - (1 - I_{es,i,s,w,t}^{dch})x_{es}^{max} \quad (29)$$

Similarly, the product $I_{es,i,s,w,t}^{ch}x_{es,i,t}$ is decoupled by including the following set of constraints:

$$z_{es,i,s,w,t}^{ch} \le x_{es}^{max}I_{es,i,s,w,t}^{ch}\ ;\ z_{es,i,s,w,t}^{ch} \le x_{es,i,t}\ ; z_{es,i,s,w,t}^{ch} \ge x_{es,i,t} - (1 - I_{es,i,s,w,t}^{ch})x_{es}^{max} \quad (30)$$

The active power limits of existing generators are given by (31). In the case of new generators, the corresponding constraints are (32). Note that the binary variables multiply both bounds to make sure that the power generation variable is zero when the generator remains either unutilized or unselected for investment.

$$P_{g,i,s,w,t}^{E,min}u_{g,i,t} \le P_{g,i,s,w,t}^E \le P_{g,i,s,w,t}^{E,max}u_{g,i,t} \quad (31)$$

$$P_{g,i,s,w,t}^{N,min}x_{g,i,t} \le P_{g,i,s,w,t}^N \le P_{g,i,s,w,t}^{N,max}x_{g,i,t} \quad (32)$$

It should be noted that these constraints are applicable only for conventional DGs. In the case of variable generation sources (such as wind and solar PV), the upper bound $P_{g,i,s,w,t}^{max}$ should be set equal to the minimum of the actual production level at a given hour, which is dependent on the level of primary energy source (wind speed and solar radiation), and the rated (installed) capacity of the generating unit. And, the lower bound $P_{g,i,s,w,t}^{max}$ in this case is simply set to zero.

The set of logical constraints in (33) ensure that an investment decision cannot be reversed. In addition to the constraints described above, the direct current (DC) based network model and radiality related constraints presented in [19] are used here.

$$x_{k,t} \geq x_{k,t-1};\ \ x_{g,i,t} \geq x_{g,i,t-1};\ \ x_{es,i,t} \geq x_{es,i,t-1} \tag{33}$$

IV. Results and Discussions

A standard IEEE 33-bus radial distribution network, shown in Fig. 1, is used here for carrying out the required analysis mentioned earlier. The system has a rated voltage of 12.66 kV, and a total demand of 3.715 MW and 2.3 MVAr. Network data and other related information about this test system can be found in [21]. Other data and assumptions made throughout this paper are as follows. The planning horizon is 3 years long, which is divided into yearly planning stages, and a fixed interest rate of 7% is used. The expected lifetime of ESS is assumed to be 15 years while that of DGs and feeders is 25 years. Two investment options with installed capacities of 0.5 and 1.0 MVA are considered for each wind and solar PV type DG units. The installation cost and emission related data of these DG units, provided in [22], are used here. For the sake of simplicity, all maintenance costs of DGs are assumed to be 2% of the corresponding investment costs while that of feeders is 450 €/km/year. The investment cost of each feeder is 38700 €/km. The current limits of all feeders is assumed to be 200 A except for those between nodes 1 and 9 which is 400 A. It is assumed that all feeders can be switched on/off, if deemed necessary.

In addition, it is assumed that wind and solar power sources are uniformly available at every node. The operational variability and uncertainty introduced by wind and solar PV type DGs, demand and electricity price are accounted for via the clustering method proposed in [23]. The maximum allowable bus voltage deviation in the system is set to 5%, and node 1 is considered as a reference with a voltage magnitude of 1.0. Annual demand growths of 0%, 5% and 10% are also considered in all simulations. Emission prices in the first, second and third stages are set to 25, 45 and 60 €/tCO2e, respectively, and the emission rate of power purchased from upstream is arbitrarily set to 0.4 tCO2e/MWh. The cost of unserved energy is 2000 €/MWh. A power factor of 0.9 is considered in the system, and is assumed to be the same throughout. The base power is set to 1 MVA.

The computed values of relevant variables are analyzed for different cases (as depicted in Table I) over the three years planning horizon. Case 1 represents the base case topology where no investments are made while Case 2 considers an optimal reconfiguration but with no investments. Cases 3 and 4 both consider investments in DGs only but differ in that the former does not change the network topology and the latter uses optimal switching. The last two cases correspond to scenarios where investments in DGs are coordinated with that of ESSs. Case 5 uses the topology in the base-case while Case 6 uses network reconfiguration. The results in Table I reveal the significant differences in overall NPV cost in the system, share of energy supplied by RES and ESS combined, cost of total network losses and unserved power among the aforementioned cases. The results are also compared with the base case system where no investments are made and the network topology is held the same. Network reconfiguration alone, as in Case 2, results in about 8.4% in the cost of losses, and a 3.1% reduction in the NPV overall system cost compared with that of Case 1.

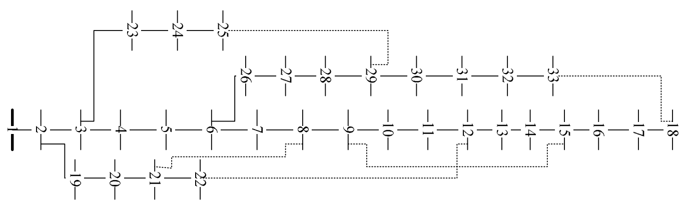

Fig. 1 Single line diagram of the test system in base case.

TABLE I. Results of Relevant Variables for Different Cases

Cases*	Total cost (*TC*) (k€)	Energy supplied by RES and ESS (%)	Total cost of losses (k€)	Total cost of unserved power (k€)	Total installed size (p.u.) Wind	Solar	ESS
1	45447.91	0.0	1089.80	1505.70	0.0	0.0	0.0
2	44044.58	0.0	997.85	0.00	0.0	0.0	0.0
3	33281.50	58.1	433.58	161.79	6.0	3.0	0.0
4	33106.07	58.2	404.59	0.00	6.0	3.0	0.0
5	26522.10	88.8	218.33	0.00	8.0	1.0	3.0
6	26516.52	88.8	212.73	0.00	8.0	1.0	3.0

**Case 1: Base case; Case 2: Optimal switching with no investment; Case 3: DG investment on base case topology; Case 4: DG investment under optimal switching; Case 5: DG and ESS investment on base case topology; Case 6: DG and ESS investment under optimal switching.*

In addition, network reconfiguration avoids a total of 396.3 kVA load curtailment (or 256.9 kVA in Case 3) that would otherwise occur at nodes 17, 18, 32 and 33 due to voltage limit constraints in Case 1.

Another more interesting observation from Table I is that Cases 3 and 4 result in (approximately) 60% reductions in the overall cost of the system and the amount of imported energy. Wind and solar power sources are complementary by nature. This important phenomenon seems to be exploited when DG investments are not accompanied by investments in ESSs (i.e Cases 3 and 4). This is because, according to the DG investment solution in Table I, the operational variability in the system seems to be handled by investing an appreciable amount in both complementary power sources (wind and solar). This can also be seen from the level of demand covered by RESs, which is about 58%.

The results corresponding to Cases 5 and 6 show that the total cost and cost of losses are dramatically reduced by more than 41.6% and 80% respectively. This reveals the substatial benefits of coordinating investments DG with ESSs. Generally, ESSs significantly improve system flexibility, enabling large-scale accommodation RES energy. Interestingly, the total amount of installed DGs (9 MW) is the same for Cases 3—6 i.e. with/without ESSs. Even if this is the case, in the absence of ESSs (Cases 3 and 4), there may be spillage of RES power when the demand is lower than the total generated power. However, the installation of ESSs leads to an efficient utilization of RES power. This is evident from the amount of energy consumption covered by the combined energy supplied by RESs and ESSs in Cases 5 and 6 is about 89%. Normally, network switching capability also improves system flexibility, leading to a high level RES penetration. In this particular study, the effect of network switching on the level of RES power absorbed by the system is not significant as one can observe in Table I. This may however be case-dependent. A more frequent switching capability could, for instance, have significant impact.

The optimal location and size of installed DGs corresponding to Cases 3 through 6 is shown in Fig. 2. The average voltage profiles at each node and for each case are depicted in Fig. 3. It is interesting to see in this figure the substantial contributions of DGs and ESS installations to voltage profile improvement. As shown in Fig. 3, the coordinated integration of DGs and ESSs (i.e. Case 6), especially leads to the best voltage profile. Fig. 4 demonstrates the optimal network topology, DG and ESS locations corresponding to this case. The benefit of joint DG and ESS investments along with network reconfiguration in terms of losses reduction (over 84% on average) can be seen from Fig. 5. The spikes observed in Case 6 are because of the variability in RES power injected into the system.

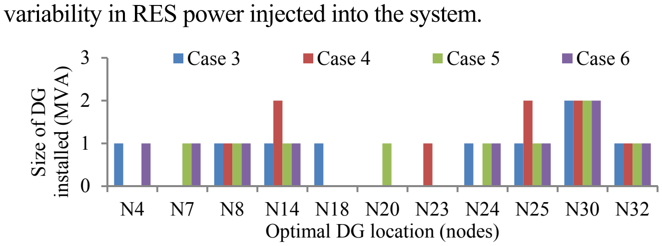

Fig. 2 Optimal placement and size of DGs under different cases.

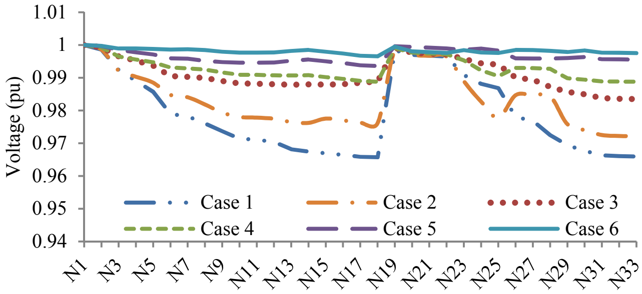

Fig. 3 Average voltage profiles in the system under different cases.

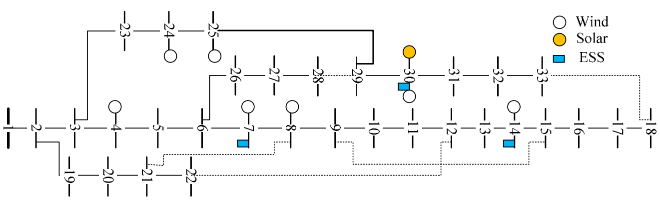

Fig. 4 Optimal locations of DGs and ESSs under Case 6 (*Opened switches 28-29, 8-21, 9-15, 18-33, 12-22*).

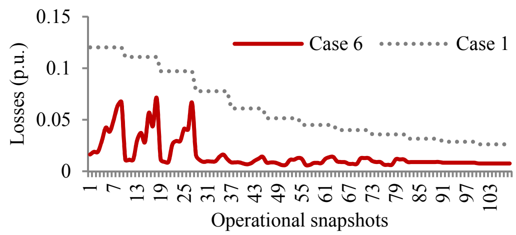

Fig. 5 Total system losses profile.

V. Conclusions

This paper has investigated the impacts of installing DESSs as well as network switching and/or reinforcement on the level of renewable power integrated in the system. A mixed integer linear programming (MILP) model was developed for this purpose, which involves joint optimization of placement and sizing of RES-based DGs and ESSs in coordination with optimal network switching. Numerical results showed the capability of ESSs integration in dramatically increasing the level and optimal exploitation of renewable DGs. According to the simulation results, the simultaneous integration of DGs and ESSs resulted in an overall cost and average losses reduction of 41% and 84%, respectively. The optimal network reconfiguration, DG and ESS installations (jointly or separately) substantially contributed to voltage stability. In the particular case study, the impact of network switching on RES power integration was not significant. However, it should be noted that this can be case-dependent.

Acknowledgment

This work was supported by FEDER funds through COMPETE and by Portuguese funds through FCT, under Projects FCOMP-01-0124-FEDER-020282 (Ref. PTDC/EEA-EEL/118519/2010) and UID/CEC/50021/2013. The research leading to these results has also received funding from the EU Seventh Framework Programme FP7/2007-2013 under grant agreement no. 309048. Moreover, Sérgio Santos gratefully acknowledges the UBI / Santander Totta doctoral incentive grant in the Engineering Faculty.

References

[1] European Council, "Conclusions on 2030 Climate and Energy Policy Framework," Brussels, Oct. 2014.

[2] M. Giacomarra and F. Bono, "European Union commitment towards RES market penetration: From the first legislative acts to the publication of the recent guidelines on State aid 2014/2020," *Renew. Sustain. Energy Rev.*, vol. 47, pp. 218–232, Jul. 2015.

[3] F. Gracceva and P. Zeniewski, "A systemic approach to assessing energy security in a low-carbon EU energy system," *Appl. Energy*, vol. 123, pp. 335–348, Jun. 2014.

[4] T. D. Corsatea, S. Giaccaria, C.-F. Covrig, N. Zaccarelli, and M. Ardelean, "RES diffusion and R&D investments in the flexibilisation of the European electricity networks," *Renew. Sustain. Energy Rev.*, vol. 55, pp. 1069–1082, Mar. 2016.

[5] H. Dagdougui, R. Minciardi, A. Ouammi, M. Robba, and R. Sacile, "A Dynamic Decision Model for the Real-Time Control of Hybrid Renewable Energy Production Systems," *IEEE Syst. J.*, vol. 4, no. 3, pp. 323–333, Sep. 2010.

[6] A. Chauhan and R. P. Saini, "A review on Integrated Renewable Energy System based power generation for stand-alone applications: Configurations, storage options, sizing methodologies and control," *Renew. Sustain. Energy Rev.*, vol. 38, pp. 99–120, Oct. 2014.

[7] A. K. Srivastava, A. A. Kumar, and N. N. Schulz, "Impact of Distributed Generations With Energy Storage Devices on the Electric Grid," *IEEE Syst. J.*, vol. 6, no. 1, pp. 110–117, Mar. 2012.

[8] Y. M. Atwa and E. F. El-Saadany, "Optimal Allocation of ESS in Distribution Systems With a High Penetration of Wind Energy," *IEEE Trans. Power Syst.*, vol. 25, no. 4, pp. 1815–1822, Nov. 2010.

[9] M. Farrokhifar, "Optimal operation of energy storage devices with RESs to improve efficiency of distribution grids; technical and economical assessment," *Int. J. Electr. Power Energy Syst.*, vol. 74, pp. 153–161, Jan. 2016.

[10] P. Meneses de Quevedo, J. Contreras, M. J. Rider, and J. Allahdadian, "Contingency Assessment and Network Reconfiguration in Distribution Grids Including Wind Power and Energy Storage," *IEEE Trans. Sustain. Energy*, vol. 6, no. 4, pp. 1524–1533, Oct. 2015.

[11] A. Bayat, A. Bagheri, and R. Noroozian, "Optimal siting and sizing of distributed generation accompanied by reconfiguration of distribution networks for maximum loss reduction by using a new UVDA-based heuristic method," *Int. J. Electr. Power Energy Syst.*, vol. 77, pp. 360–371, May 2016.

[12] A. Zidan and E. F. El-Saadany, "Distribution system reconfiguration for energy loss reduction considering the variability of load and local renewable generation," *Energy*, vol. 59, pp. 698–707, Sep. 2013.

[13] A. S. Bouhouras and D. P. Labridis, "Influence of load alterations to optimal network configuration for loss reduction," *Electr. Power Syst. Res.*, vol. 86, pp. 17–27, May 2012.

[14] R. Rajaram, K. Sathish Kumar, and N. Rajasekar, "Power system reconfiguration in a radial distribution network for reducing losses and to improve voltage profile using modified plant growth simulation algorithm with Distributed Generation (DG)," *Energy Rep.*, vol. 1, pp. 116–122, Nov. 2015.

[15] T. T. Nguyen, A. V. Truong, and T. A. Phung, "A novel method based on adaptive cuckoo search for optimal network reconfiguration and distributed generation allocation in distribution network," *Int. J. Electr. Power Energy Syst.*, vol. 78, pp. 801–815, Jun. 2016.

[16] G. Papaefthymiou, K. Grave, and K. Dragoon, "Clean Energy Solutions Center | Flexibility Options in Electricity Systems," Mar. 2014.

[17] F. Capitanescu, L. F. Ochoa, H. Margossian, and N. D. Hatziargyriou, "Assessing the Potential of Network Reconfiguration to Improve Distributed Generation Hosting Capacity in Active Distribution Systems," *IEEE Trans. Power Syst.*, vol. 30, no. 1, pp. 346–356, Jan. 2015.

[18] L. Blank and A. Tarquin, *Engineering Economy*, 7th ed. New York: McGraw-Hill Science/Engineering/Math, 2011.

[19] G. Munoz-Delgado, J. Contreras, and J. M. Arroyo, "Joint Expansion Planning of Distributed Generation and Distribution Networks," *IEEE Trans. Power Syst.*, vol. 30, no. 5, pp. 2579–2590, Sep. 2015.

[20] H. P. Williams, *Model Building in Mathematical Programming*, 4th ed. Wiley, 1999.

[21] S. A. Taher and M. H. Karimi, "Optimal reconfiguration and DG allocation in balanced and unbalanced distribution systems," *Ain Shams Eng. J.*, vol. 5, no. 3, pp. 735–749, setembro 2014.

[22] Z. F. Desta, A. W. Bizuayehu, M. Shafie-khah, J. P. S. Catalão, M. Asenso, and J. Contreras, "DG Investment Planning Analysis with Renewable Integration and Considering Emission Costs," in *the 16th Int. Conf. on Computer as a Tool, EuroCon2015*, Salamanca, 2015.

[23] Gregorio Muñoz-Delgado, Sergio Montoya-Bueno, Miguel Asensio, Javier Contreras, JoséI Muñoz, and JoséM Arroyo, "Renewable Generation and Distribution Grid Expansion Planning," in *Smart and Sustainable Power Systems*, CRC Press, 2015, pp. 345–404.