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Multi Flexibility Options Integration to Cope with Large-Scale Integration of Renewables

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***Abstract*—Conventional electrical networks are slowly changing. A strong sense of policy urges as well as commitments have recently been surfacing in many countries to integrate more environmentally friendly energy sources into electrical systems. In particular, stern efforts have been made to integrate more and more solar and wind energy sources. One of the major setbacks of such resources arises as a result of their intermittent nature, creating several problems in the electrical systems from a technical, market, operation and planning perspectives. This work focuses on the operation of an electrical system with large-scale integration of solar and wind power. In order to cope with the intermittency inherent to such power sources, it is necessary to introduce more flexibility into the system. In this context, Demand Response, Energy Storage Systems and Dynamic Reconfiguration of the system are introduced and the operational performance of the resulting system is thoroughly analyzed. To carry out the required analysis, a stochastic MILP operational model is developed, whose efficacy is tested on an IEEE 119-bus standard network system. Numerical results indicate that the joint deployment and management of various flexibility mechanisms into the system can support a seamless integration of large-scale intermittent renewable energies.**

***Index Terms*—Demand response, dynamic reconfiguration, energy storage systems, renewable energy sources, stochastic MILP**

I. Nomenclature

A. Sets

c/Ω^c	Index/set of switchable capacitor banks
es/Ω^{es}	Index/set of Energy Storage Systems (ESSs)
g/Ω^{DG}	Index/set of Renewable Energy Sources (RESs)/Distributed Generators (DGs)
i/Ω^i	Index/set of buses
k/Ω^k	Index/set of branches
$h', h/\Omega^h$	Index/set of hourly snapshots
s/Ω^s	Index/set of scenarios
$\varsigma\,/\Omega^\varsigma$	Index/set of substations

B. Parameters

SC_k	Switching cost of each branch k (€ per single switching)
$E_{es,i}^{min}, E_{es,i}^{max}$	ESSs upper and lower bounds (MWh)
ER_g, ER_ς^{SS}	Emission rates of DGs, and emissions intensity of purchased energy, respectively (tCO_2e/MWh)
g_k, b_k, S_k^{max}	Conductance, susceptance and flow boundaries of each branch k (S, S, MVA)
R_k, X_k	Resistance, Reactance (Ω, Ω)
MP_k, MQ_k	Big-M parameters related with active and reactive power flows over each branch k
$OC_{g,i,s,h}$	Price of unit energy production (€/MWh)
N_i, N_ς	Number of buses and substations, respectively
$P_{es,i}^{ch,max}, P_{es,i}^{dch,max}$	Charging and discharging power bounds of ESSs (MW)
$P_{solar,h}$	Hourly solar PV output (MW)
P_r	Rated power of RES unit (MW)
$P_{wind,h}$	Hourly wind power output (MW)
v_{ci}	Cut-in wind speed (m/s)
v_{co}	Cut-out wind speed (m/s)
v_h	Sampled wind speed (m/s)
R_c	Certain radian point (usually 150W/m^2)
R_h	Hourly solar radiation (W/m^2)
R_{std}	Standard condition of solar radiation (usually 1000W/m^2)
V_{nom}	Rated voltage of the system (kV)
Z_k	Impedance of each branch k (Ω)
$\lambda_{s,h}^{CO_2e}$	Emissions price (€/tCO_2e)
$\lambda_{s,h}^{\varsigma}$	Electricity price at the substation level (€/MWh)
$\overline{\lambda_s^\varsigma}$	Considered average price of electricity at substation level (€/MWh)
λ_s^{Valley}	Considered average electricity price in valley hours (€/MWh)
$\lambda_s^{Off-peak}$	Considered average electricity price in off-peak hours (€/MWh)
λ_s^{Peak}	Considered average electricity price in peak hours (€/MWh)
$\lambda_{es,i,s,h}^{dch}$	Variable cost of storing energy in ESSs (€/MWh)
$\eta_{es}^{ch}, \eta_{es}^{dch}$	Charging/discharging efficiency (%)
ρ_s	Probability of hourly scenario s
$\upsilon_{s,h}$	Unserved power penalty factor (€/MW)
$\xi_{h,h'}$	Price elasticity of electricity demand
α	Percentage of demand that can be scheduled
Δh	Time increment (hour)
μ_{es}	Scaling factor (%)
pf_g, pf_{ss}	Power factor of RES and substation, respectively

C. Variables

$PD_{s,h}^i, QD_{s,h}^i$	Active and reactive power demand at bus i (MW, MVAr)
$E_{es,i,s,h}$	Energy storage level (MWh)
$I_{es,i,s,h}^{dch}, I_{es,i,s,h}^{ch}$	Discharging/charging binary indicator variables

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$P_{g,i,s,h}, Q_{g,i,s,h}$	Active and reactive power produced by RESs at bus i (MW)
$P^{SS}_{ς,s,h}, Q^{SS}_{ς,s,h}$	Active and reactive power imported from the substation (MW)
P_k, Q_k, θ_k	Active and reactive power flows respectively, and voltage angle difference of branch k (MW, MVAr, radians)
PL_k, QL_k	Active and reactive power losses of each branch k (MW, MVAr)
$PL_{ς,s,h}, QL_{ς,s,h}$	Active and reactive power losses at substation ς (MW, MVAr)
$P^{dch}_{es,i,s,h}, P^{ch}_{es,i,s,h}$	Discharged/charged power of ESSs (MW)
$P^{NS}_{i,s,h}$	Unserved active power at bus i (MW)
$Q^{NS}_{i,s,h}$	Unserved reactive power at bus i (MVAr)
V_i, V_j	Voltage magnitudes at bus i and j (kV)
$u_{k,h}$	Switching (binary) variables of existing branches
θ_i, θ_j	Voltage angle at node i and j (radians)
$\varphi^{RTP}_{s,h}$	Real-time price of electricity (€/MWh)
$x_{k,h}$	Binary variable to indicate line status
$y^+_{k,h}, y^-_{k,h}$	Auxiliary variables to indicate the status of a line

D. Functions (units in M€)

EC^{SS}_h	Expected cost of energy imported through the substation level
EC^{DG}_h	Expected cost of energy produced by DGs
EC^{ES}_h	Expected cost energy discharged from ESSs
$EmiC^{DG}_h$	Expected emission cost due to DG power production (€)
$EmiC^{SS}_h$	Expected emission cost of energy imported through the substations (€)
TSC	Total expected costs of line switching
TEC	Total expected costs of supplied energy
$TENSC$	Total expected costs of energy not supplied
$TEmiC$	Total expected costs of emissions

II. Introduction

A. Background

THE decarbonization of our electrical system brings new challenges for the electrical network. From the European perspective, for example, in a short period of time, European countries are facing the closure of significant parts of their generation mix in response to the Large Combustion Plant directive [1]. This can reduce the margins of capacity of generation to unsafe levels. In addition, the issues surrounding climate change have exacerbated the problem of fossil fuel shortages [2],[3].

Similarly, given the fact that electrical networks are old infrastructures, conventional management methods of such networks are becoming obsolete [4]. The growth of demand, concerns with CO_2 emissions and varied consumption profiles raise new reasons for investigating new solutions.

In the topic of Smart Grids, several solutions have been studied to operate electrical networks more efficiently, more environmentally friendly and with better reliability indices. A recent phenomenon is that the share of distributed Renewable Energy Sources (RESs) in the overall power production mix has been increasing in many countries. One of the benefits of such integration is to reduce network losses because generation is placed closer to demand. However, its inherent intermittence and lack of competitive storage mechanism are currently raising one of the greatest issues on the continued development of these clean energy technologies.

When a large number of these energy sources are integrated into network systems, several problems may arise. One of the problems has to do with the rapid changes in the solar and wind power generation during the operation time. And, this is due to the variability and uncertainty such power sources. Other problems that come with the integration of renewables are of a technical nature such as the adjustment of network security and protection, quality of service, and bi-directional power flows among others.

Despite several benefits, it is sometimes argued that an upgraded dispatch of these technologies may increase energy costs and reduce the overall efficiency of the system [5]. For example, in the countries of northern Europe, where there is already a lot of renewable power generation, there often appears a problem of excess electricity production. Although excess energy production can be exported to other countries, interconnection capability may not be sufficient. When renewable power production is high, excess production may force the system operator to dispatch down wind turbines until demand and supply are balanced.

As conventional methods have been limited to being based on the use of High Cost/Low Efficiency peaking plants or curtailment of renewable power generation, the system operator needs to have more flexibility options that are economical and rapidly acting resources [6].

In relation to all this, the focus so far has mainly been on Demand Response (DR), Dynamic System Reconfiguration (DSR) and deployment of Energy Storage Systems (ESSs). A system reconfiguration aims to obtain the power network topology that best suits conditions in the system at a particular moment (which can be on an hourly, daily or seasonal basis). DR and ESSs can achieve the same goals, not needing a market structure during emergency situations. The objectives of these two technologies can be load shifting, peak clipping, valley filling, strategic conservation and flexible load shaping [7].

In the medium term, large-scale integration of RESs brings new challenges that evoke wider system flexibility needs. And, in the long term, the electrification of heating and transportation can put more pressure on system integration. So, the flexibility on the demand side can partly fill in the needs described above. If well incentivized, demand can be more responsive to system requirements. It can also cope with the stochastic behavior of RESs in the absence of proper energy storage media.

The economic effects of the introduction of large-scale RESs on energy systems are related to the profile, balances and network-related costs that can come as a reduction in revenue for the provision of RESs or as additional costs, such as the cost of integration for market-specific participants.

From the perspective of the overall energy system, the levelized cost of electricity (LCOE) of the RES power generation compromises the LCOE of the technology itself and the cost of integration. The current magnitude of RES integration costs depends on the flexibility of each system, i.e. to what extent demand-side and supply-side can accompany the inherent variability of wind and solar systems. It should be noted here that flexibility is the ability to balance rapid changes in the renewable production and forecasting errors of the energy system or can be described as a general characteristic of the ability of a specific aggregation of generators to respond to the variation and uncertainty of the network load [8].

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TABLE I. LITERATURE REVIEW FROM RELATED WORKS

Ref.	Year	Methodology	Planning	Operation	Wind	Solar	DR/EMS	ESS	Switching	Stochastic	Flexibility	Analysis
[25]	2018	Multiagent based MILP		✓			✓	✓				Multi-microgrid operation
[26]	2017	MILP		✓	✓		✓	✓		✓	✓	Day-ahead scheduling microgrid
[27]	2017	Lagrange duality method and distributed finite-time consensus algorithm		✓	✓		✓	✓				Economic dispatch of a microgid
[28]	2016	MILP		✓	✓	✓	✓	✓		✓		Short-term operation
[29]	2018	Monte Carlo Simulation	✓		✓		✓				✓	Assessment of the capacity credit of RESs
[30]	2016	Non-dominated Sorting Genetic Algorithm	✓		✓	✓		✓	✓			DG siting and sizing in the presence of ESSs
[31]	2018	MILP	✓				✓	✓			✓	Evaluation of the impact of wind curtailment
[32]	2018	Sequential Monte Carlo		✓	✓	✓		✓	✓	✓		Analysis after a fault with formation of microgrids
[33]	2017	MILP		✓	✓	✓	✓	✓		✓		Analysis of the bidding strategy for grid-connected microgids
This paper	-	SMILP		✓	✓	✓	✓	✓	✓	✓	✓	Short-term operation analysis of a distributed system

B. Literature Review

In general, flexibility in the traditional electrical system has been dominated by conventional thermal units. On the other hand, the current electricity system has incorporated a flexible set of resources, namely DR, market, ESSs and DSR among others, to help mitigate the impact of RESs integration (namely the variability and uncertainty), in addition to the uncertainty associated with demand itself. The different types of flexibility sources mentioned, i.e. DR, market, ESS and DSR, have been explored by different approaches in the literature and in different configurations. From these resources, the first three are the most commonly used in the literature; while the last one is rarely exploited as a source of flexibility for the system.

Among the approaches present in the literature, there is a set of works that explore DR's flexibility [9]–[22]. In [21], a description of the flexibility resources by the DR to balance the system at the planning level is presented, not considering any other source of flexibility other than DR. Another set of approaches (more embracing) is the flexibility that comes from the junction of DR and ESSs. Within this set of works, there are different configurations in the approaches. A very significant set explores the flexibility of the DR in the form of demand side management, for residential heating and also cooling considering thermal energy storage systems [9], [11], [19], [20].

A new active control form of heating/cooling systems in the smart grid context is explored in [9], with the aim of promoting the integration of RESs. Mubbashir *et al.* [11] present a work to increase the system's operational flexibility focusing on scaling up the integration of wind power generation together with DRs, but in the absence of intelligent network management using real-time thermal rating to support hourly wind power production. A similar work is presented in [10] whose focus is on mitigating the wind power output fluctuations by means of demand response.

In addition to these approaches, there is still a set of works that use the core of the previous approaches, but adding/replacing some aspects or entities in the optimization process, namely, electric vehicles, ancillary services, market scheme or dynamic prices [10], [12], [13], [15]–[18], [23], [24].

In [24], the potential of flexible demand resources such as heat pumps and thermal storage in local industries is studied. The optimization process of this work also considers the presence of electric vehicles (EVs) and RESs. In [15], some business models in the electrical sector are explored to evaluate the flexibility mechanisms over time. The works in [16] and [23] focus on the flexibility generated from ancillary services. In [16], a demand side management methodology is presented based on the aggregation/ disaggregation of residential thermal storage for different time intervals, ensuring the thermal comfort of the individual dwellings. In [23], a load aggregation methodology is presented based on the prioritization of loads according to their flexibility. Different types of flexible loads are categorized as thermostat-controlled loads (TCL), non-TCL and battery-based non-TCL and non-urgent loads.

The works in [12] and [18] have taken market in to consideration. In [12], a day-ahead hourly pricing (DAHP) mechanism is proposed for distributed DR in uncertain and dynamic environments considering electricity price in the retail market, in order to be applied in later works with DR, ESSs, and renewable integration. In [18], an Optimal Bidding Strategy for a DR aggregator is presented in the Day-Ahead Market in the presence of demand flexibility. Good and Mancarella in [22] have presented a multi-energy work in order to ensure that thermal comfort cannot be degraded beyond agreed limits in the event of a call. The approach is demonstrated through a case study that illustrates how the different flexibility options can be used to integrate more electric heat pumps into a capacity constrained smart district that is managed as a community energy system, while maximizing its revenues from multiple markets/services. There are also approaches that seek only the flexibility on the generation side, as is the case of [30], [34]–[36]. These works investigate the flexibility of a system featuring RESs and ESSs. In [34], the flexibility resulting from the joint integration of RESs and ESSs is investigated. Steffen and Weber in [35] investigate the effect of pumping storage as a means of system flexibility to accommodate a higher level of RES in the considered system. In [36], a case study of China for RES expansion is presented, analyzing the flexibility constraints in the low-carbon policy.

It should be pointed out that majority of the existing approaches reviewed here focus on the planning level [9], [11], [15], [21], [24], [29], [31], [35]–[39] and not in terms of system operation. Moreover, Table I provides a summary of existing works that are closely related to the present work. From this table, it is possible to verify that there are very few works that consider DSR as a flexibility source, and those which consider this resource do not approach it from a flexibility analysis perspective, as it is the case in [30] and [31].

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Therefore, despite the existence of several works in the area of power systems flexibility, most of the works in the literature focus on the flexibility that can be obtained from the demand side, in heating and cooling schemes of residential houses, or in conjugation with EV in the presence of RESs.

It should be noted that, with the exception of the works that consider EV, the ESSs considered throughout the vast majority of the remaining works are of the thermal storage type (by the process described above) or combined with industrial thermal storage through aggregation that aim supply the residential sector. In the presence of large-scale integration of RESs, this work differs from the previous ones because it considers the existence of DSR, ESSs (battery-type) and DR, analyzing the impacts of such a mix from the flexibility perspective.

For the best knowledge of the authors, this analysis has not yet been done in any other work in the existing literature. The current work aims to further assess the level of RES integration in the energy mix with this approach.

In addition to the flexibility analysis perspective, this work also presents a new optimization model that considers the uncertainty and variability of the renewables, which is one of the salient contributions of our work.

C. Contributions and Paper Organization

The contributions of this work can be defined as:

- A linearized AC-OPF (Alternating Current - Optimum Power Flow) based stochastic mixed-integer linear programming (S-MILP) model for modeling the electric network systems with large-scale integration of RESs and flexibility options. The resulting model attains the right balance between accuracy and computational complexity;
- Quantitative and qualitative analysis, discussions and comparison of results that are obtained for various case studies related to the level of flexibility options as a way of dealing with intermittency and variability of RESs;
- Joint integration of DR, ESSs and DSR into the electrical system to ensure efficient utilization of RES energy production.

The remainder of this work is organized as follows. The third section presents a complete description of the developed algebraic model. In the fourth section, the system used for a case study and analysis of the results are presented and discussed. The fifth and final section contains some concluding remarks.

III. Handling Uncertainty and Variability

A. Description

Uncertainty in this work refers to the degree of precision that each parameter is measured. As for variability, it is referred to as “the natural variation in time of a specific uncertain parameter” [40]. These terminologies are employed and followed in this work when referring to operational variability and uncertainty. For example, demand can be characterized by its hourly variability that has associated some degree of uncertainty, associated to the error that can be introduced by predicting the demand.

In this work, scenarios are used for the operation period. A scenario represents a sequence of events of an uncertain parameter. For example, the RES power output uncertainty is translated by a possible number of story lines. The operation period is the time window where the operation variables are being analyzed. In this paper, an operation period of 24 hours is defined.

In the current work, the uncertainty and variability associated to the considered problem are taken into account through a stochastic process. For a given stochastic parameter, instead of being considered as only a single evolution mode, different possible realizations are considered, each with associated probability.

B. Uncertainty and Variability Generation

Variability and uncertainty are non-exclusive characteristics of renewable power generation. There are other parameters in the optimization process that are also characterized by these variables [41]. In this work, three sources of uncertainty and variability are identified, namely wind, solar and demand.

To account for demand uncertainties, two demand profile scenarios are taken, considering a ±5% prediction error margin from real-life short-term demand profile (i.e. 24 hours) [42]. This then leads to three demand scenarios, which are used in the analysis. Wind speed and solar radiation are generated following the methodology in [40]. The average wind speed and solar radiation profiles are obtained based on real data. These values are plugged in equations (1) and (2) to obtain the respective power outputs. The power outputs cannot be used straightforward because they may not directly maintain the proper correlation with the average demand profile. Therefore, the power outputs should be readjusted to replicate the time-based correlations that happen between demand, solar radiation and wind speed. The correlation between wind and solar, wind and demand, and solar and demand are respectively -0.3, 0.28, 0.5, being obtained from [40].

After obtaining the correlation matrix, the wind and solar power outputs can be transformed into new ones, given the correlation between them. Cholesky factorization is used to adjust the data series. The method consists of having a correlation matrix R, uncorrelated data D, so that a new data C, whose correlation matrix is R, is generated by multiplying the Cholesky decomposition of R by D. The power output profiles are determined by using these readjusted values. Note that the following power curve is used in converting the wind speed into power:

$$P_{wind,h} = \begin{cases} 0; & 0 \leq v_h \leq v_{ci} \\ P_r\left(A + Bv_h^3\right); & v_{ci} \leq v_h \leq v_r \\ P_r; & v_r \leq v_h \leq v_{co} \\ 0; & v_h \geq v_{co} \end{cases} \quad (1)$$

In eq. (1), parameters A and B are given by the expressions in [43] and [44]. In the same way, the solar power output are determined using the following expression [45]:

$$P_{solar,h} = \begin{cases} \dfrac{P_r\, R_h^2}{R_{std} R_c}; & 0 \leq R_h \leq R_c \\ \dfrac{P_r\, R_h}{R_{std}}; & R_c \leq R_h \leq R_{std} \\ P_r; & R_h \geq R_{std} \end{cases} \quad (2)$$

Uncertainty pertaining to wind and solar power productions is assumed to have ±15% deviation from the average power output profiles. This translates approximately to a ±5% forecasting error in wind speed or solar radiation. The hourly profiles of wind and solar power outputs are constructed based on the considered deviations. This is transformed into three wind and solar power outputs profiles (namely, high, low and average).

The individual scenarios of demand, wind and solar power outputs are combined to form a set of 27 scenarios (i.e. 3*3*3). All of these scenarios are expected to be equally probable with ρ_s equal to 1/27.

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IV. Model Formulation

A. Objective Function

To carry out the required analysis and account for the variability and uncertainty inherent to the problem at hand, a stochastic MILP optimization model is formulated. Model accuracy is guaranteed because the subsequent optimization model employs a linearized AC-OPF based network model, which has the right balance between accuracy and computational requirements.

The resulting optimization model minimizes the algebraic sum of four relevant cost terms while fulfilling a number of technical and economic constraints. These cost terms are related to network switching, operation, unserved power and emissions in the system:

$$Minimize\ TC = TSC + TEC + TENSC + TEmiC \tag{3}$$

The first term in (3) is related to the total switching costs that is a result of the distribution network reconfiguration (DNR). Note that a switching cost occurs when the status of a given feeder changes from open (0) to closed (1) or vice-versa. This gives the absolute difference between sequential switching operations in time. The absolute difference in (4) is represented by a module, and it can be linearly represented by introducing two non-negative variables: $y_{l,h}^{+}$ and $y_{l,h}^{-}$. TSC is therefore expressed by the following equation:

$$TSC = \sum_{k\in\Omega^k}\sum_{h\in\Omega^h} SC_k * \Delta h * \left(y_{k,h}^{+} + y_{k,h}^{-}\right) \tag{4}$$

where:

$$x_{k,h} - x_{k,h-1} = y_{k,h}^{+} - y_{k,h}^{-};\ y_{k,h}^{+} \geq 0;\ y_{k,h}^{-} \geq 0 \tag{5}$$

$$x_{k,0} = 1;\ \forall k \in \Omega^1\ and\ x_{k,0} = 0;\ \forall k \in \Omega^0 \tag{6}$$

The sets Ω^1 and Ω^0 refer to the normally closed feeders and tie lines, respectively. The statuses of the feeders and tie lines can change during the optimization period i.e. depending on the optimal topology obtained following the dynamic network reconfiguration. *TEC*, the second term in (3), characterizes the expected production costs of energy by distributed generations, ESSs and by importing power from the transmission system:

$$TEC = EC^{DG} + EC^{ES} + EC^{SS} \tag{7}$$

Each term in (7) can be defined as:

$$EC^{DG} = \sum_{s\in\Omega^s}\rho_s\sum_{h\in\Omega^h}\Delta h\sum_{g\in\Omega^g} OC_{g,i,s,h}P_{g,i,s,h} \tag{8}$$

$$EC^{ES} = \sum_{s\in\Omega^s}\rho_s\sum_{h\in\Omega^h}\Delta h\sum_{es\in\Omega^{es}} \lambda_{es,i,s,h}^{dch}P_{es,i,s,h}^{dch} \tag{9}$$

$$EC^{SS} = \sum_{s\in\Omega^s}\rho_s\sum_{h\in\Omega^h}\Delta h\sum_{\varsigma\in\Omega^{\varsigma}} \lambda_{s,h}^{\varsigma}P_{\varsigma,s,h}^{SS} \tag{10}$$

The expected cost of energy not supplied is formulated in *TENSC*; that is, the third term in (3). The load not supplied can be in the form of active and reactive power. Hence, this is computed the following expression:

$$TENSC = \sum_{s\in\Omega^s}\rho_s\sum_{h\in\Omega^h}\Delta h\sum_{i\in\Omega^i}\left(\upsilon_{s,h}^{P}P_{i,s,h}^{NS} + \upsilon_{s,h}^{Q}Q_{i,s,h}^{NS}\right) \tag{11}$$

Here, $\upsilon_{s,h}^{P}$ and $\upsilon_{s,h}^{Q}$ define penalty parameters for active and reactive power that is not supplied. These two parameters are each set to a sufficiently high value, which roughly quantifies the value of lost load. The fourth and the last term in (3), *TEmiC*, is related to the expected costs of emissions in the system. These costs are a result of producing power using local DG resources and by importing power from the transmission system:

$$TEmiC = EmiC^{DG} + EmiC^{SS} \tag{12}$$

The terms in (12) are calculated by the following expressions:

$$EmiC^{DG} = \sum_{s\in\Omega^s}\rho_s\sum_{h\in\Omega^h}\Delta h\sum_{g\in\Omega^g}\sum_{i\in\Omega^i}\lambda^{CO_2}ER_gP_{g,i,s,h} \tag{13}$$

$$EmiC^{SS} = \sum_{s\in\Omega^s}\rho_s\sum_{h\in\Omega^h}\Delta h\sum_{\varsigma\in\Omega^{\varsigma}}\sum_{i\in\Omega^i}\lambda^{CO_2}ER_{\varsigma}^{SS}P_{\varsigma,s,h}^{SS} \tag{14}$$

B. Constraints

The healthy operation of the distribution system is guaranteed by the technical and economic constraints that are respected during all operational times. One of the major technical constraints is the Kirchhoff's current law [40], which states that the sum of all flows arriving at a bus must be always equal to the sum of all flows leaving that bus at any time.

Therefore, the active power flows (15) and reactive power flows (16) should be respected. Equation (15) includes in the incoming flows the active power produced by distributed generators, the power flows associated to the feeder (incoming), the power that is being discharged from ESSs and the power that is being imported from the transmission system (P^{SS}) if the considered bus has a substation. On the other hand, the outgoing flows consider the demand, losses and power flows associated to the feeders.

$$\begin{aligned}\sum_{g\in\Omega^g} P_{g,i,s,h} + \sum_{es\in\Omega^{es}}\left(P_{es,i,s,h}^{dch} - P_{es,i,s,h}^{ch}\right) + P_{\varsigma,s,h}^{SS} + P_{i,s,h}^{NS} \\ + \sum_{in,k\in\Omega^k} P_{k,s,h} \\ - \sum_{out,k\in\Omega^k} P_{k,s,h} = PD_{s,h}^{i} \\ + \sum_{in,k\in\Omega^k}\frac{1}{2}PL_{k,s,h} \\ + \sum_{out,k\in\Omega^k}\frac{1}{2}PL_{k,s,h}\ ;\forall\varsigma\epsilon\Omega^{\varsigma};\ \forall\varsigma\epsilon i;\ k\epsilon i\end{aligned} \tag{15}$$

$$\begin{aligned}\sum_{g\in\Omega^g} Q_{g,i,s,h} + Q_{c,i,s,h}^{c} + Q_{\varsigma,s,h}^{SS} + Q_{i,s,h}^{NS} + \sum_{in,k\in\Omega^k} Q_{k,s,h} \\ - \sum_{out,k\in\Omega^k} Q_{k,s,h} = QD_{s,h}^{i} \\ + \sum_{in,k\in\Omega^k}\frac{1}{2}QL_{k,s,h} \\ + \sum_{out,k\in\Omega^k}\frac{1}{2}QL_{k,s,h}\ ;\forall\varsigma\epsilon\Omega^{\varsigma};\ \forall\varsigma\epsilon i;\ k\epsilon i\end{aligned} \tag{16}$$

The power flow in any feeder must respect the Kirchhoff's voltage law. This is considered by including linearized power flow equations. This linearization follows two assumptions. First, the voltage angle difference θ_k is normally very small in distribution networks. In trigonometric approximations, this results in

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$\sin\theta_k \approx \theta_k$ and $\cos\theta_k \approx 1$. Second, the bus voltage magnitudes are expected to be close to the rated value V_{nom} in distribution systems. By using these simplifying assumptions, the complex nonlinear and nonconvex flow equations can be linearized as in [40]:

$$\left|P_{k,s,h} - \left(V_{nom}\left(\Delta V_{i,s,h} - \Delta V_{j,s,h}\right)g_k - V_{nom}^2 b_k \theta_{k,s,h}\right)\right| \leq MP_k\left(1 - u_{k,h}\right) \tag{17}$$

$$\left|Q_{k,s,h} - \left(-V_{nom}\left(\Delta V_{i,s,h} - \Delta V_{j,s,h}\right)b_k - V_{nom}^2 g_k \theta_{k,s,h}\right)\right| \leq MQ_k\left(1 - u_{k,h}\right) \tag{18}$$

where $\Delta V^{min} \leq \Delta V_{i,s,h} \leq \Delta V^{max}$ and $\theta_{l,s,h}$ is defined as $\theta_{k,s,h} = \theta_{i,s,h} - \theta_{j,s,h}$, i and j resemble to the same line k. Note that $\Delta V_{i,s,h}$ corresponds to the voltage deviation at node i (from the nominal value) in a given scenario and hour. The transfer capacity of each line should respect the maximum power flow limits, given by:

$$P_{k,s,h}^2 + Q_{k,s,h}^2 \leq (S_k^{max})^2. \tag{19}$$

In addition, active and reactive power losses in each feeder are given by:

$$PL_{k,s,h} = \frac{R_k\left(P_{k,s,h}^2 + Q_{k,s,h}^2\right)}{V_{nom}^2} \tag{20}$$

$$QL_{k,s,h} = \frac{X_k\left(P_{k,s,h}^2 + Q_{k,s,h}^2\right)}{V_{nom}^2} \tag{21}$$

To model ESSs, the following constraints are added [40]:

$$0 \leq P_{es,i,s,h}^{ch} \leq I_{es,i,s,h}^{ch} P_{es,i,h}^{ch,max} \tag{22}$$

$$0 \leq P_{es,i,s,h}^{dch} \leq I_{es,i,s,h}^{dch} P_{es,i}^{ch,max} \tag{23}$$

$$I_{es,i,s,h}^{ch} + I_{es,i,s,h}^{dch} \leq 1 \tag{24}$$

$$E_{es,i,s,h} = E_{es,i,s,h-1} + \left(\eta_{es}^{ch} P_{es,i,s,h}^{ch} - \frac{P_{es,i,s,h}^{dch}}{\eta_{es}^{dch}}\right)\Delta h \tag{25}$$

$$E_{es,i}^{min} \leq E_{es,i,s,h} \leq E_{es,i}^{max} \tag{26}$$

$$E_{es,i,s,h0} = \mu_{es} E_{es,i}^{max};\ E_{es,i,s,h24} = \mu_{es} E_{e.s,i}^{max} \tag{27}$$

Equation (22) and (23) set the limits of power charged and discharged, respectively. In (24), it is ensured that the operation of charging and discharging of ESSs does not occur at the same time. Equation (25) denotes the state of charge. Equation (26) ensures that the storage level is within the permissible range. Eq. (27) ensures that the storage level at final time period is the same as the initial storage level.

The active and reactive power limits of power generators are generally enforced by adding the following constraints:

$$P_{g,i,s,h}^{min} \leq P_{g,i,s,h} \leq P_{g,i,s,h}^{max} \tag{28}$$

$$Q_{g,i,s,h}^{min} \leq Q_{g,i,s,h} \leq Q_{g,i,s,h}^{max} \tag{29}$$

In the case of wind and solar PV power generators, $P_{g,i,s,h}^{min}$ is often set to zero; whereas, $P_{g,i,s,h}^{max}$ is determined by the strength of primary energy resources (wind speed and solar radiation). Hence, it is set to the actual power production, $P_{g,i,s,h}$.

In the case of variable power generators such as wind and solar PV, the expressions related to reactive power production constraints are derived based on the assumption that each of the variable power generators are operated at a constant power factor, pf_g. In addition, conventional wind and solar PV sources do not often have the capability to provide reactive power support; hence, they are operated at a constant and lagging or unity power factor. Under such an operation, the following constraints should be used:

$$Q_{g,i,s,h} = \tan\left(\cos^{-1}(pf_g)\right) * P_{g,i,s,h} \tag{30}$$

Whereas, for wind and solar PV type DGs with reactive power support capabilities such as doubly fed induction generator based wind turbine and voltage source inverter based PV, the following constraints are used:

$$-tan\left(cos^{-1}(pf_g)\right) P_{g,i,s,h} \leq Q_{g,i,s,h} \leq tan\left(cos^{-1}(pf_g)\right) P_{g,i,s,h} \tag{31}$$

The above two inequalities, i.e. (31), show that the wind and solar type DGs are capable of operating between pf_g leading power factor (capacitive) and pf_g lagging power factor (reactive). This means such DGs are capable of "producing" and "consuming" reactive power depending on the operational situations in the system. Note that the upper and lower bounds in (31) are determined by assuming a constant power factor operation. But the reactive power production or consumption can assume any optimal value between these bounds, depending on the operational situation of the system.

Also, the reactive power at the substation bus should be subject to reactive power limits (again under the assumption of constant power factor operation):

$$-\tan\left(cos^{-1}(pf_{ss})\right) P_{\varsigma,s,h}^{SS} \leq Q_{\varsigma,s,h}^{SS} \leq \tan\left(cos^{-1}(pf_{ss})\right) P_{\varsigma,s,h}^{SS} \tag{32}$$

To account for DR, the following equations are introduced. Note that it is accounted for responsive active and reactive demand [46]:

$$PD_{s,h}^{i} = PD_{s,h}^{i,0}\left(1 + \alpha \sum_{h'} \xi_{h,h'} \left(\frac{\varphi_{s,h}^{RTP} - \lambda_s^{flat}}{\lambda_s^{flat}}\right)\right) \tag{33}$$

$$QD_{s,h}^{i} = QD_{s,h}^{i,0}\left(1 + \alpha \sum_{h'} \xi_{h,h'} \left(\frac{\varphi_{s,h}^{RTP} - \lambda_s^{flat}}{\lambda_s^{flat}}\right)\right) \tag{34}$$

$$\lambda_s^{flat} = \frac{\sum_h \lambda_{s,h}^{\varsigma}}{24} \tag{35}$$

$$\varphi_{s,h}^{RTP} \begin{cases} \lambda_s^{Valley} = \dfrac{\sum_h \lambda_{s,h}^{\varsigma}}{8}, & h \in [1-8] \\ \lambda_s^{Off-Peak} = \dfrac{\sum_h \lambda_{s,h}^{\varsigma}}{10}, & h \in [9-18] \\ \lambda_s^{Peak} = \dfrac{\sum_h \lambda_{s,h}^{\varsigma}}{6}, & h \in [19-24] \end{cases} \tag{36}$$

The parameters $PD_{s,h}^{i,0}$ and $QD_{s,h}^{i,0}$ reflect active and reactive power before DR implementation. The average electricity price of the day (32) is assumed to be the flat price. The Real Time Pricing $\varphi_{s,h}^{RTP}$ is divided into three categories corresponding to valley, off-peak and

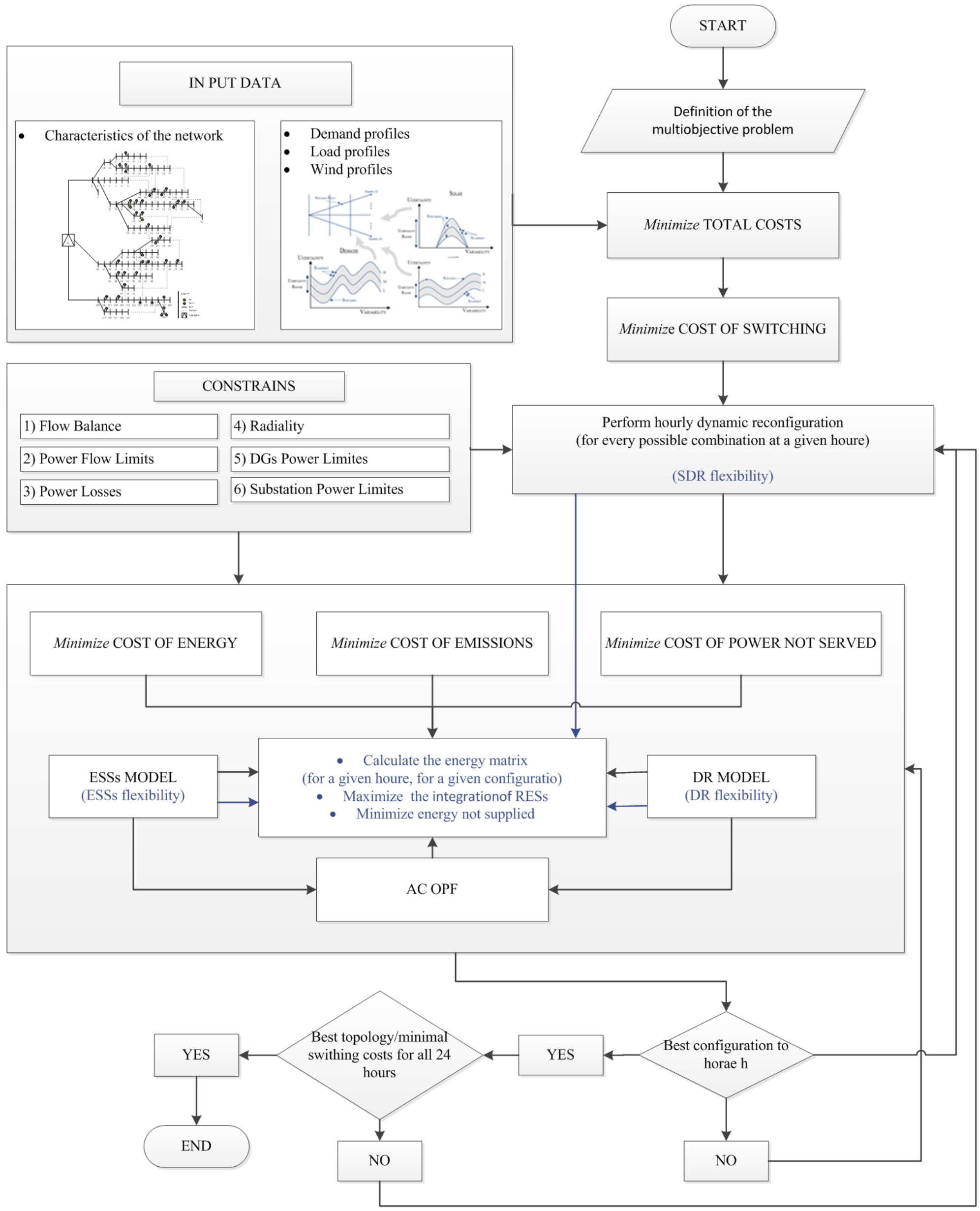

Figure 1. Methodology flowchart.

peak times of demand profile (35). Each one is the average of the price in that time.

Table II contains the elasticities $\xi_{h,h'}$, considered in the simulations. In addition to the above constraints, it must be ensured that the distribution system operates radially. For this, the radiality constraints in [47] are included in our model.

C. Methodology

The present methodology is explained in the flowchart presented in Fig. 1. This model is composed by a multiobjective approach in the perspective of minimizing the total costs considering the stochastic nature of RESs (solar and wind) as well as the demand. Therefore, the total costs are minimized considering four cost terms: the cost of switching, the cost of energy, the cost of energy not supplied, and the cost of emissions. The aim of the optimization is to obtain a coordinated model where the benefits of flexibility found through the use of DSR, DR ESS modeling along with an AC OPF model are verified, for example, in terms of allowing for greater integration of RESs.

V. Case Study, Numerical Results and Discussions

A. Network Data and Assumptions

In this work, the 119-bus test system (whose schematic diagram is shown in Fig. 2) is used to perform the numerical analysis.

The system has a nominal voltage of 11 kV and demand of 22709.72 kW and 17041.068 kVAr. More information about this test system can be found in [48]. Also, according to [48], active power losses of the system are 1298.09 kW, and the minimum voltage in the system is 0.8783 p.u., occurring at bus 116.

The size and location of RESs and ESSs, and also the power factor of RESs and assumed variable costs of ESSs, are all taken

TABLE II. Elasticity Matrix

	Valley	Off-Peak	Peak
Valley	-0.2	0.008	0.008
Off-Peak	0.01	-0.2	0.008
Peak	0.012	0.008	-0.2

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from [48]. The following further assumptions are made in the simulations. The analysis is made for a 24-hour period. The voltage deviation at any node is constrained to fall within ±5% of the nominal value (including boundaries). The reference node is the only substation, whose voltage magnitude and its angle are set to 1 p.u. and 0, respectively. The power factor at the substation is considered to be 0.8, adapted from [47]; the power factor of RESs is 0.95. Both values are held constant for all simulations.

The emission rate at the substation is set to 0.4 $\mathrm{tCO_2e/MWh}$, and that of solar and wind power generation technologies are set to 0.0584 $\mathrm{tCO_2e/MWh}$ and 0.0276 $\mathrm{tCO_2e/MWh}$, respectively. The emissions price is set to 6 $€/\mathrm{tCO_2e}$. These data are in accordance with [49]. The variable operation and maintenance costs for generating power from wind and solar technologies are set to 20 €/MWh and 40 €/MWh, respectively, according to [49].

The charging and discharging efficiencies of ESSs are considered the same and have a value of 90%, adapted from [50] and [51]. Discharging power from ESSs have a unit price of 5 €/MWh, which represents the variable operation and maintenance cost of the storage system.

Unserved active and reactive power was adapted from [47] and have a fixed penalty of 3000 €/MWh. Feeders have a maximum capacity of 400A, except the feeders {(1, 2); (2, 4); (1,66); (66,67)} whose respective maximum capacity is set to 1200A and feeders {(4, 5); (5, 6); (6, 7); (4,29); (29,30); (30,31); (67,68); (67,81); (81,82); (1,105); (105,106); (106,107)} each having a maximum capacity of 800A.

The percentage of demand that can be responsive (α) was set to 20%. The losses linearization process consider 5 partitions, which is in line with the findings in [52].

B. *Case Studies and Numerical Results*

The analysis in this work considers four case studies whose results are discussed and analyzed. Case 1 refers to the Base Case where no RESs and flexibility options are considered. In this case, the lower voltage bound is removed to avoid an unacceptably huge amount of unserved power because of the lack of adequate reactive power compensation mechanism in the original system.

The second case jointly integrates DNR with large scale integration of RESs (and, this is designated as "Without ESSs"). The third case considers ESS deployments in addition to the conditions in the second case (This is hereinafter referred to as the "Plus ESSs" case). The last case is similar to the third case but including DR. Since this case considers all available flexibility options with RESs, it is hereinafter referred to as "Full Flex" case. Table III summarizes the distinctive features of each case.

The relevant costs of the objective function of each case are presented in Table IV. Analyzing the results, the Base Case has the highest expected total costs compared to the other cases due to only importing energy from upstream. Also, because DGs and ESSs are not considered, it has the highest emission costs.

In Case 2, where DNR and DGs are considered, the expected total costs are reduced by 42.7% since there is a reduction in terms of purchased energy from the upstream grid, which is more expensive than the one locally produced by the DGs, allowing the costs to drop. Moreover, since wind and PV power sources have lower emission rates, the expected cost related to emissions is also lower than that of the Base Case. Similarly, active power losses are reduced by 63% and reactive power losses by 65%. As expected, the deployment of DGs in the system lowers power losses because part of the overall energy consumed is met by the locally placed DGs. The expected cost related to the power not supplied also sees a reduction of 82%. In Fig. 3, the energy mix for this case is depicted, where DGs are added to the system and represent a large part of the energy mix. In this case, the utilization of wind is about 57% and that of PV is about 4%, which brings the total demand covered by RES-based DGs to 61% of the total energy produced.

TABLE III. DISTINGUISHING THE CASES CONSIDERED IN THE ANALYSIS

	DSR	DGs	ESSs	DR	Voltage Limits
Base Case	No	No	No	No	Not imposed
Without ESSs	Yes	Yes	No	No	Imposed
Plus ESSs	Yes	Yes	Yes	No	Imposed
Full Flex	Yes	Yes	Yes	Yes	Imposed

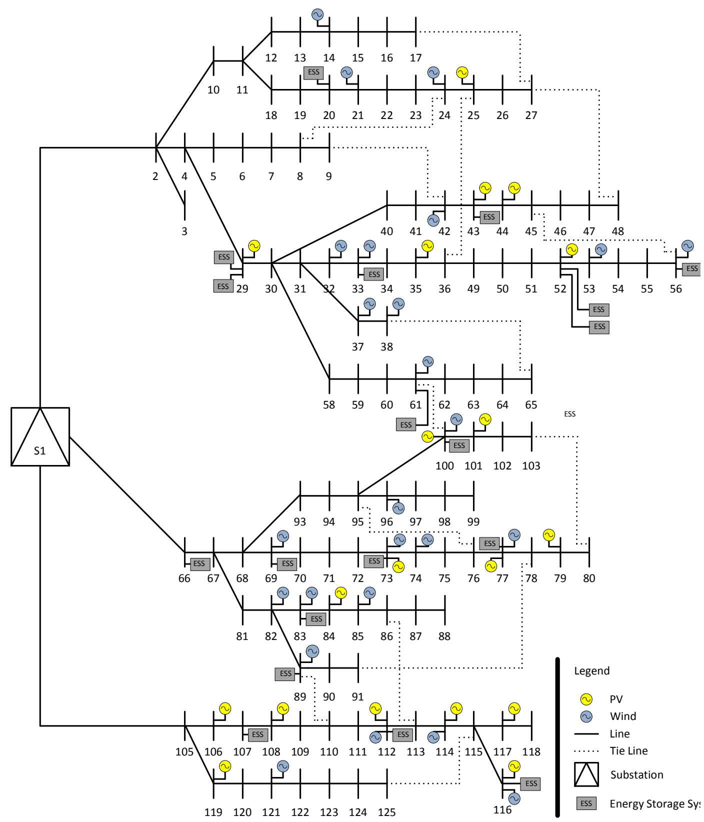

Figure 2. A schematic diagram of the 119-bus test system.

Concerning the case with ESSs, i.e. Case 3, it is possible to see a further reduction in the total expected costs by 53%. In this case, it is also clear that adding different energy sources in the mix will have a positive impact in the expected energy costs, since discharging the energy stored in the ESSs is cheaper than importing energy from upstream. This is due to the fact that the stored energy is mainly sourced from wind and PV generations. Also, ESSs do not have emission costs; therefore, the expected costs of emissions are reduced by 30% and 72% compared to that of the "Without ESSs" case and "Base Case", respectively. In the "Plus ESSs" case, there are no instances of load shedding; and hence, no associated costs. This is because adding ESSs into the system along with joint operation with DGs will use the excessive energy produced by DGs to be stored, leading to a better fulfillment of demand in peak hours with more valuable and cheaper energy. In this context, ESSs increase the flexibility of the system, allowing a more efficient use of power produced by "variable type" DGs. Comparing with the "Without ESSs" case, the power losses are not affected very much; yet, a small reduction is achieved between the cases with DGs.

TABLE IV. TERMS OF OBJECTIVE FUNCTION AND POWER LOSSES

	Base Case	Without ESSs	Plus ESSs	Full Flex
Total Cost (€)	33408.66	19151.81	15657.50	15257.59
TSC (€)	0.00	1050.00	1020.00	1010.00
TEC (€)	31355.50	17442.59	14281.01	13901.64
TEmiC (€)	1255.31	516.20	356.50	345.96
TENSC (€)	797.85	143.02	0.00	0.00
P Losses (MW)	20.25	7.45	6.35	6.29
Q Losses (MW)	14.11	4.95	4.19	4.13

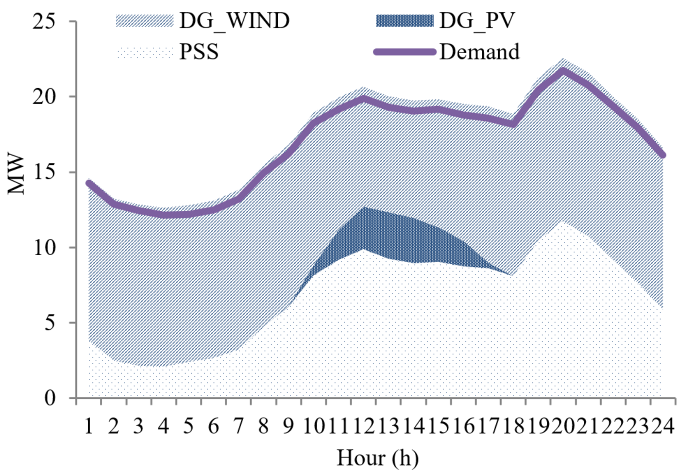

Figure 3. Aggregated energy mix in the "Without ESSs" case.

The last case, "Full Flex", where all available flexibility options are considered, a 2.6% reduction in expected total costs is attained compared with "Plus ESSs".

The aggregated energy mix for the case with full flex is shown in Fig. 4. Compared with the Base Case, the expected total costs are reduced by 54%. In addition, the expected energy costs are reduced by 56%, expected emissions cost drops by 72%, active power losses are reduced by 69% and reactive power losses by 71%. The case with full flexibility has the best outcome in terms of expected costs and in terms of power losses among all cases considered. It can be seen that, as far as adding more flexibility in the system is concerned, the costs with DNR are being reduced from the case "Without ESSs" to the case "Full Flex". This shows that the system needs less dynamic switching between time periods when more flexibility options are considered. The dynamic reconfiguration of the system for the "Full Flex" case can be seen in Table V for the 24 hours of the operating period.

The aggregated energy mix in the "Full Flex" case (presented in Fig. 4) shows very interesting results. The integration of DGs and ESSs dramatically decreases the usage of energy imported from upstream. The percentage of PV and wind usage in the mix is 7% and 65%, respectively while ESSs account for 3% of the energy demand. This leads to a total of 76% of demand fulfilled by DGs and ESSs. Local demand is largely supplied by these technologies. The ESSs are being charged during the day, benefiting from the presence of solar starting at 9h and still charging during peak hours, where there is a lot of wind power production. ESSs are discharged between the second and the seventh hour during the course of the day because there is no energy production from PV, and energy from wind production is at its lowest compared to the rest of the time period. In this manner, power import is kept at low level, benefiting the system with integration of ESSs by reducing costs. The profile of demand scheduled is also presented in Fig. 4.

TABLE V. HOURLY RECONFIGURATION OUTCOME IN THE "FULL FLEX" CASE

Hour	Open Lines $x_{k,h} = 0$	Hour	Open Lines $x_{k,h} = 0$
1	23, 26, 34, 61, 82, 90, 95, 117, 119, 121, 122, 124, 127, 128, 130	13	23, 26, 34, 53, 61, 90, 95, 119, 121, 124, 127, 128-130, 131
2	23, 26, 34, 42, 61, 76, 82, 85, 90, 95, 119, 122, 124, 127, 131	14	23, 34, 61, 74, 82, 85, 118, 119, 121, 122, 124-126, 131
3	23, 26, 34, 61, 74, 76, 82, 85, 90, 95, 119, 121, 122, 124, 131	15	23, 34, 61, 74, 82, 85, 117-119, 124-126, 128
4	23, 26, 34, 53, 61, 74, 76, 82, 85, 90, 95, 118, 121, 124, 131	16	23, 34, 39, 53, 61, 85, 118, 119, 121, 125-129, 131
5	23, 26, 34, 42, 53, 61, 74, 76, 82, 90, 95, 118, 124, 130, 131	17	23, 26, 34, 53, 61, 74, 90, 95, 117, 118, 121, 124, 128-130
6	23, 26, 34, 53, 61, 74, 76, 82, 90, 95, 118, 121, 124, 130, 131	18	23, 26, 34, 53, 61, 90, 95, 119, 121, 124, 127-131
7	23, 26, 34, 42, 61, 74, 76, 90, 95, 119, 122, 124, 129-131	19	26, 34, 39, 53, 61, 85, 118, 120, 121, 125, 126-128, 129, 131
8	23, 26, 34, 53, 61, 82, 85, 90, 95, 119, 121, 124, 127, 128, 131	20	26, 34, 39, 61, 74, 119-122, 125, 126, 128-130,131
9	23, 26, 34, 61, 82, 85, 90, 95, 119, 121, 122, 124, 126-128, 131	21	26, 39, 61, 74, 85, 118, 120-122, 125, 126, 128, 129, 131, 132
10	23, 26, 34, 39, 53, 61, 90, 95, 119, 121, 127-130, 131	22	23, 34, 39, 53, 61, 76, 82, 85, 118, 119, 121, 125-127, 131
11	23, 26, 34, 39, 53, 61, 74, 118, 121, 125, 128-130, 131	23	23, 26, 34, 53, 61, 74, 82, 85, 119, 121, 124-126, 131
12	23, 26, 34, 39, 61, 85, 90, 119, 121, 122, 125, 116-129, 131	24	23, 26, 34, 42, 53, 74, 82, 85, 90, 95, 117, 119, 123, 124, 128

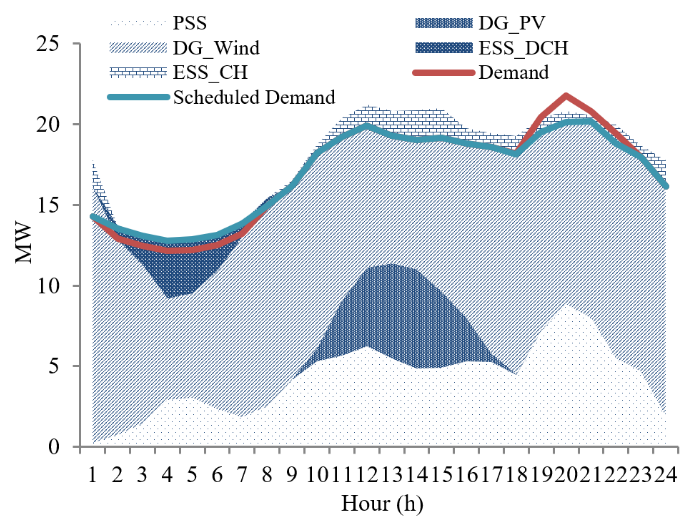

Figure 4. Aggregated energy mix in the "Full Flex" case

Another important factor to analyze is the average voltage profile in the system. In Fig. 5, the average voltage profile for all considered cases is shown. To be in a healthy operation, the voltage magnitude at each bus should be close to the rated (nominal) value. Nevertheless, the voltage will vary within a range in the nodes of the system. In Fig. 5, it is clear that, with increasing flexibility options in the system, the voltage deviation will get flatter, improving the voltage profile and keeping each node's voltage close to the nominal value (i.e. with 0% deviation). Fig. 5 clearly shows that the "Full Flex" case has the best voltage profile in the resulting system. In the "Full Flex" case, the system has a mean voltage deviation value of nearly -0.4%. Obviously, implementing only DNR in the system can also lead to a better average voltage profile, as clearly observed in this figure.

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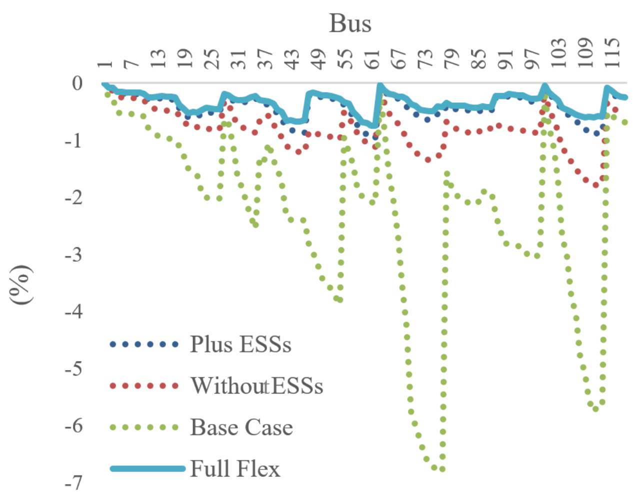

Figure 5. Average system voltage deviation comparison between the considered cases.

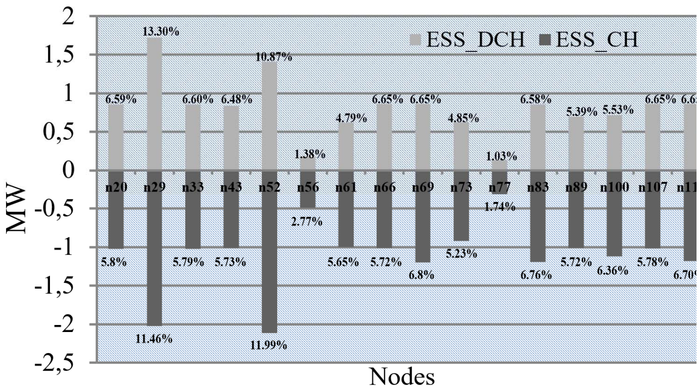

Figure 6. Percentage of ESSs charge and discharge cycle by node in the "Full Flex Case".

In Fig. 6, it is possible to observe the ESSs' charge and discharge at each node for the "Full Flex" case as well as the respective contribution of each ESS, which on average has increased 2% compared with the "Plus ESSs" case. Demand in peak hours is being reduced and is scheduled to valley hours. This leads to lower losses in the system, and an improved voltage profile due to lower stresses in the feeder's power flows. Correspondingly, the usage of DGs and ESSs are optimized because there is less demand to be fulfilled in peak hours, leading to a less congested network during that period. This is also reflected in the reduction of power losses.

VI. Conclusions

This work has presented an extensive analysis in relation to the joint integration of flexibility options as a way to cope with the intermittent nature of DG power productions (mainly wind and solar PV) and their efficient usage. To perform the analysis, a stochastic MILP optimization model has been developed. The resulting model is of an operational nature, and aims to operate the distribution systems featuring large scale integration of DGs while fulfilling a number of technical and economic constraints. The constrained optimization is based on a linearized AC-OPF model, and has an objective function encompassing the sum of expected costs related with the operation of distribution systems that is minimized subject to a range of operational and economic constraints. A 119-bus distribution network system is used to test the developed model. Numerical results show that large scale integration of DGs can be achieved if this is coordinated with optimal deployment of ESSs and DR. A more efficient utilization of wind and solar resources can be achieved as a result. According to the simulation results, as high as 76% of the demand can be covered by energy coming from wind, PV and ESSs, and most importantly without having dramatic impacts on the considered system in terms of its healthy operation. In addition, the expected operation costs are considerably reduced, while the voltage profile in the system is also improved. Generally, as the level of flexibility in the system increases, managing the intermittent nature of wind and solar power is made easier.

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