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Estimating the Active and Reactive Power Flexibility Area at the TSO-DSO Interface

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***Abstract*- The penetration of Distributed Renewable Energy Sources (DRES) in the distribution grid is increasing considerably in the last years. This is one of the main causes that contributed to the growth of technical problems in both transmission and distribution systems. An effective solution to improve system security is to exploit the flexibility that can be provided by Distributed Energy Resources (DER), which are mostly located at the distribution grids. Their location combined with the lack of power flow coordination at the system operators interface creates difficulties in taking advantage of these flexible resources. This paper presents a methodology based on the solution of a set of optimization problems that estimate the flexibility ranges at the TSO-DSO boundary nodes. The estimation is performed while considering the grid technical constraints and a maximum cost that the user is willing to pay. The novelty behind this approach comes from the development of flexibility cost maps, which allow the visualization of the impact of DER flexibility on the operating point at the TSO-DSO interface. The results are compared with a sampling method and suggest that a higher accuracy in the TSO-DSO information exchange process can be achieved through this approach.**

***Index Terms*-- Distributed energy resources, flexibility, optimal power flow, roles, TSO-DSO cooperation.**

I. Introduction

THE increasing penetration of Distributed Renewable Energy Sources (DRES) in distribution grids has become an operational and planning challenge for both distribution and transmission system operators (DSO and TSO). Technical problems (e.g., voltage problems, branch congestion) will occur more frequently in both networks turning more difficult for the network operators to keep the quality of service and security of supply. On the other hand, there is a foreseen increase of flexibility from smart appliances, electric vehicles, storage and new regulation for ancillary services from DRES. Flexibility can be perceived as the response of a specific resource to an external signal (e.g. price signal or activation) through the modification of its injection and/or consumption pattern, thus providing a service to the system [1].

As grid managers, both TSO and DSO are responsible for the secure operation of their respective networks. Although the current legislations of some countries allow the DSO to contract flexibility (e.g. Sweden, Finland) [2], the overall system security is mostly ensured by the TSO [3]. In fact, the cooperation between TSO and DSO is rarely observed regarding most grid operation challenges (e.g. congestion management, voltage support). In most countries, the TSO contract ancillary services from Distributed Energy Resources (DER) directly connected to the distribution networks in order to meet these challenges [4]. The changing environment that is rising in the distribution grids due to the increase of DER is a clear indication that a close cooperation between TSO and DSO will be mandatory so that the systems security can be improved [5]. Within this context, and in order to allow a secure and safe operation of both grids while accessing flexibility, services such as flexibility estimation and technical validation conducted by the DSO should be studied both at the regulatory and algorithmic levels. Although the regulatory framework is not the focus of this work, its impact upon these services should be evaluated through sensitivity analysis. The core of this paper is the estimation of the flexibility available in the distribution network that once activated by TSO and/or DSO do not lead to technical problems on it.

A wide spectrum of potential flexibility services provided by DER are identified and studied in [6] focusing on the definition of relevant value chains, commercial arrangements and recommendations to overcome the current regulatory barriers. In this context, the inclusion of DER in ancillary services provision has been intensively studied. In [7], a mathematical approach is proposed to aggregate flexibility of thermostatically controlled loads (represented by a "virtual battery") aiming to provide regulation services to the TSO. The same topic is addressed in [8] by exploiting a "virtual" battery model together with a Nash-bargaining based coordination strategy to provide demand response services. The work presented in [9] is a step forward regarding the integration and use of aggregated models. By approximating the aggregate feasible regions of active and reactive power consumed by a set of DER to an ellipsoid in the PQ domain, [9] paves the way to include DER flexibility in the

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transmission level dispatch.

The use of flexibility in the planning domain is also covered by the literature. In [10], the flexibility envelope concept is introduced to evaluate if DER flexibility is enough to meet the reserve requirements in terms of time, ramping rate, capacity and stored energy.

A common subject to the different types of flexibility services is the impact of forecast uncertainty on their provision. While [11] uses a robust procurement algorithm to guarantee that, in a worst case scenario of uncertainty, there is enough locational flexibility to address a specific disturbance, [12] details an innovative metric to measure potential flexibility shortage events that is based on the comparison between the largest variation range of uncertainty that allows the system to remain in operation and the target range.

Regarding the interaction of DER with the markets, the FlexPower project [13] developed the idea of a real-time market for balancing power which considers the participation of aggregated small-scale DER. Having in mind that some specific grid issues such as voltage violations should be addressed by DER located at the area where they occur, [14] describes the concept of local flexibility markets. In [15] a market targeting the DSO needs with respect to flexibility services activation is detailed by defining contractual prerequisites, e.g. quality and penalty specifications, price calculation.

When assessing flexibility exploitation options, it is crucial to define which will be the roles of both system operators. The "Reforming the Energy Vision" plan [16] assigns the responsibility to integrate and use DER as primary means to meet system needs to a new stakeholder category – the Distribution System Platform Provider (DSPP). Within the same context, the Universal Smart Energy Framework (USEF) [17] defines a conceptual role framework that focuses on how flexibility exploitation should occur while guaranteeing secure operation and equal access to all stakeholders. It is a broader perspective that assigns to the aggregator a central role in providing flexibility to balance responsible parties, DSO and TSO. The GridWise Council developed the transactive energy conceptual architecture, which relies on topics that go from policy and market design to cyber-physical infrastructures that will allow an effective DER integration [18]. The evolvDSO project [19] applied the IEC PAS 62559 use case methodology and defined eight new and evolving DSO roles for efficient DRES integration in distribution networks. One of these roles, "Contributor to System Security" supports TSO-DSO cooperation. This specific topic is also addressed in the SmartNet project [4] by proposing five TSO-DSO coordination schemes. Different degrees of involvement by system operators are considered regarding the prequalification, procurement, activation and settlement of ancillary services. [20] presents a new interaction model integrated in the agent-based testbed DSIMA that tries to prevent TSO and DSO from simultaneously activating flexibility in opposite directions.

The exploitation of flexibility options to improve system security and TSO-DSO cooperation cannot be dissociated. The focus of this paper is the development of a tool capable of supporting a regulatory scenario where TSO and DSO coordinate and exchange data in order to ensure that the activation of DER flexibility allows a safe power flow control at their interface (i.e. within the technical constraints). A conceptual framework, called technical virtual power plant is proposed in [21] and assumes that the DSO can control and maintain a fixed active and reactive power profile at the TSO-DSO boundary nodes. However, in this evolving environment, it is necessary to consider the flexibility available in the distribution grid and estimate how its activation would impact on these power exchanges. The idea of estimating the flexibility range at the primary substations appears in [22]. It is based on a sampling approach that simulates power flows in the MV network. The limitations found in [22] paved the way to the methodology described in the present paper.

This paper proposes a methodology to estimate the flexibility range of active and reactive power at the TSO-DSO boundary nodes (primary substations). It is based on solving several optimization problems, which use the optimal power flow (OPF) algorithm concepts. The methodology follows one of the system use cases defined in [23] and focuses on the business use case "Managing TSO requests at different timeframes" [24]. The novelty behind this methodology is related with the capability of estimating the entire perimeter of the flexibility area in the PQ plan, which overcomes the main limitations of [22], i.e. estimates extreme points of flexibility. In practical terms, the flexibility area illustrates the PQ limits that the power flow at the TSO-DSO interface can assume through feasible activations of DER flexibility. The output is a set of flexibility areas corresponding to different maximum costs (i.e. a flexibility map) for each time instant of the forecast horizon. The information contained in each flexibility map can be used both in the planning and operational domains. In fact, it shows to network operators if distribution network technical constraints are limiting the activation of the available flexibility. Moreover, in the operational domain (e.g., hours/day-ahead) it supports the TSO in delimiting possible control actions to overcome the technical problems created by high DRES integration levels. Regarding the temporal resolution, it is only dependent on the forecast availability. Due to the specific characteristics of this modified OPF and for the sake of simplicity, the methodology presented here will be called Interval Constrained Power Flow (ICPF) [25].

The rest of the paper is organized as follows: Section II details the flexible resources typically available in a distribution grid, shows their cost assessment formulas and presents the concept of flexibility map. In Section III, the optimization approach developed to estimate the flexibility area is described while in Section IV a case study is used to evaluate the methodology effectiveness. Section V performs a critical analysis of the results outlining the lessons learned, the main benefits and limitations and also paves the way to Section VI that summarizes the research work and discusses future steps.

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II. Interval Constrained Power Flow Framework

A. General Architecture

Fig. 1 shows the framework of the ICPF highlighting the inputs that feed the optimization algorithm and its expected outcomes.

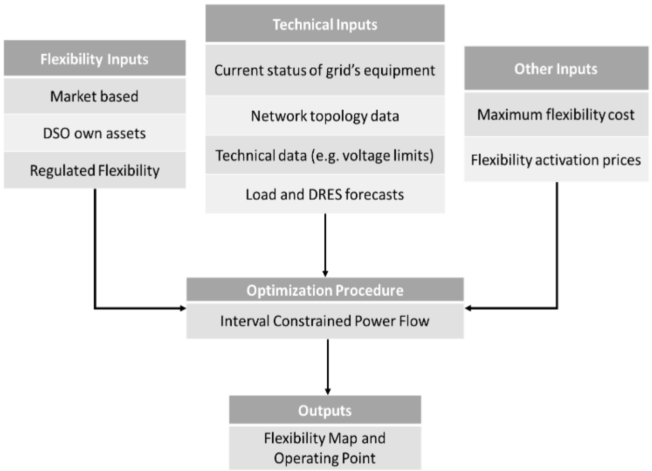

Fig. 1. General architecture of the ICPF

The definition of the flexibility ranges and corresponding activation prices depends on the type of scheme used to acquire flexibility services (e.g., market offers, non-firm grid connection contracts). In this work, it is assumed the existence of flexibility markets or flexibility contracts where the DSO can be an active player by purchasing or requiring flexibility volumes [24]. The current status of grid's equipment and the topology data are also necessary to describe the current state of the system. At each time instant of the forecast horizon, possible changes in the structure of the grid (e.g., network reconfiguration actions) should be displayed through these two inputs. Regarding the technical data, it informs the optimization algorithm about the network technical limits. The maximum flexibility cost indicates how much the user (e.g., TSO) is willing to pay to activate flexibility services.

Load and DRES forecasts can be used as an input to the ICPF method in order to build the future operating points and the flexibility maps.

B. Input: Flexibility of Different Types

The flexibility range available at the TSO-DSO boundary nodes is dependent on different types of flexible resources connected to the distribution grid. These resources can be divided into three categories: (i) market based, which consists in active power flexibility offered by aggregators or other market players (e.g., loads, storage, DRES) in short-term flexibility markets (e.g., traditional reserve markets) or in flexibility tenders for a mid-term horizon; (ii) network assets usually owned by the DSO, such as on-load tap changer (OLTC) transformers, reactive power compensators; (iii) "regulated flexibility" like non-firm connection contracts with large consumers and DRES, in which the flexibility providers typically allow their power output to be curtailed during some hours per year in exchange for a connection license. In this paper, the traditional reserve markets are given as an example for purchasing flexibility, but assuming that DER connected to the distribution grid participate in this market. However, any type of market platform providing flexibility options to the network operators can be considered by the proposed methodology.

The activation of flexibility constitutes a service that is being provided by the corresponding resources, thus having an associated cost[1]. The cost calculation formula for the flexibility usage can differ between resources.

- *Load and Generators flexibility cost:*

$$Cost_{LoadFlex} = \sum_{k=1}^{N_L}\left[c_k^{PL}(\Delta P_k^L) + c_k^{QL}(\Delta Q_k^L)\right] \quad (1)$$

$$Cost_{GenFlex} = \sum_{i=1}^{N_G}\left[c_i^{PG}(\Delta P_i^G) + c_i^{QG}(\Delta Q_i^G)\right] \quad (2)$$

where ΔP_k^L, ΔQ_k^L, ΔP_i^G and ΔQ_i^G illustrate the amount of active and reactive power flexibility activated from each load k and generator i (e.g. DRES). c_k^{PL}, c_k^{QL}, c_i^{PG}, c_i^{QG} represent the activation cost function for each MWh or Mvarh of flexibility provided by these network assets. The activation price comes directly from the price in the offer submitted by the market agent to the flexibility market.

- *OLTC transformer flexibility cost:*

$$Cost_{OLTC} = \sum_{t=1}^{N_T}\left[c_t^{OLTC}(\Delta tap_{ij}^t)\right] \quad (3)$$

where Δtap_{ij}^t illustrates the tap variation of each OLTC t connecting nodes i and j. c_t^{OLTC} cost (in m.u.) is the cost function of changing the OLTC position to its neighbor. In [26], a model for optimal reactive power dispatch is presented and tries to minimize the global costs (i.e. considering the costs required to adjust the control devices set points).

- *Reactive power compensator flexibility cost:*

$$Cost_{RC} = \sum_{c=1}^{N_c}\left[c_c^{RC}(\Delta Q_c^{position})\right] \quad (4)$$

Where $\Delta Q_c^{position}$ is linked with the variation in terms of position of each reactive power compensator c. The corresponding cost function is given by c_c^{RC} (in m.u.). Here, we consider only condensator based power compensators. The cost of synchronous compensators with continuous variation can be calculated using the formulas already defined for load and generators in (1) and (2), respectively. Each cost function varies with the direction (i.e. upward or downward) and magnitude of the flexibility requested as well as with the market offers of the flexibility operators. Although the current version of the algorithm considers a quadratic cost function, it would be straightforward to include a different relation. The effectiveness of the proposed methodology would not be affected by such change.

The sum of all these costs results in the total flexibility cost

[1] This work assumes that only a price per activation in m.u./MWh (or Mvarh) is paid. Thus, a price per flexibility capacity in m.u./MW (or Mvar) is not considered, although its inclusion in the model is straightforward.

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to pay for activating the flexible assets of a specific distribution grid. The maximum total cost that the user is willing to pay to activate the flexibility can be set as a constraint in the optimization. The optimization algorithm, which is the core of the ICPF is described in Section III.

C. Output: Active and Reactive Power Flexibility Map

The active and reactive power flexibility map is the output from which a set of benefits can be extracted. Fig. 2 depicts an illustrative example of what is delivered by the ICPF algorithm.

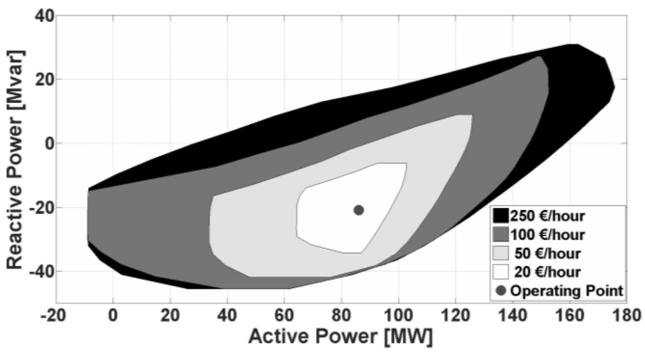

Fig. 2. Example of flexibility areas for different maximum flexibility costs

The map presents four different flexibility areas. Each one corresponds to a maximum flexibility cost. Thus, each area shows a region of feasible points that can be implemented at the TSO-DSO boundary nodes by paying, at maximum, the corresponding cost for flexible resources activation. The flexibility area grows with the cost that the user is willing to pay. If no flexibility is activated, the system will work on the scheduled operating point (circle point in Fig. 2).

The visual information provided by the flexibility maps gives a significant support for: (i) estimate the minimum cost to move the operating point from the scheduled to another one by activating flexible resources available in the distribution grid without violating any technical constraint; (ii) support the fulfilment of regulatory requirements in terms of reactive power ratio in the TSO-DSO interface. The flexibility areas present a set of feasible alternatives to the predicted operating point that can help the decision-maker find the best way to comply with the pre-defined values. This last aspect is relevant in several countries. For instance, in Portugal, the DSO incurs penalties if the reactive power flow at the TSO-DSO boundary nodes exceeds certain limits conditioned to the period of the day and tan φ range [27]; the Italian regulator also studied a model where the DSO is obliged to maintain a scheduled cumulative program with regards to each single HV/MV substation or to one zone that includes more than one HV/MV substation [28]. It is important to emphasize that the flexibility maps do not provide the flexibility combination(s) (i.e. DER set-points) needed to achieve a specific variation of the TSO-DSO operating point. Instead, they inform if such variation can be achieved within the grid technical limits and estimate the minimum cost to pay for it.

III. Optimization Methodology

This section presents an efficient computational solution to estimate the active and reactive power flexibility at the TSO-DSO interface. The developed algorithm is based on the formulation of an optimization problem that automatically adapts itself to find the perimeter of the flexibility area.

A. Optimization Problem Formulation

The flexibility area is not defined only by adding the flexibility provided by the resources available in the distribution grid; this would be represented by a larger rectangle in the PQ plan (Fig. 3). The technical network restrictions affect the flexibility area, as illustrated by the smaller rectangle in Fig. 3. Moreover, the interdependency between active and reactive power flows would also lead to a flexibility area with a completely different shape compared with this smaller rectangle, as illustrated in Fig. 3. Therefore, it is a challenge to estimate the extreme values of active and reactive power at the same time due to its “irregular” shape.

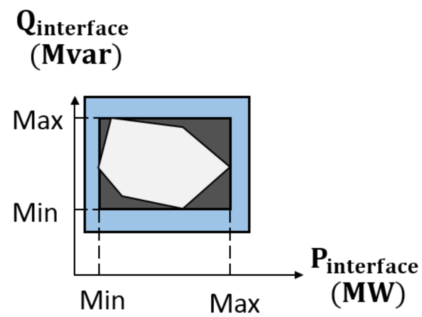

Fig. 3. Illustration of the impact of PQ interdependency and specific network characteristics upon the flexibility area

The challenge is to find the shape of the flexibility area by identifying which parts of the larger rectangle are feasible. Thus, it is necessary to define an objective function whose minimization allows to capture the perimeter of the flexibility area.

$$\alpha\, P_{DSO\rightarrow TSO} + \beta\, Q_{DSO\rightarrow TSO} \tag{5}$$

where $P_{DSO\rightarrow TSO}$ and $Q_{DSO\rightarrow TSO}$ are the active and reactive power injections at the TSO-DSO boundary nodes. This objective function (5) represents a family of straight lines whose slope θ is defined by the coefficients α and β ($\tan\theta = \alpha/\beta$). The minimization of the objective function for different values of θ will lead to different points of the perimeter of the flexibility area.

The decision variables of the optimization problem are the activated flexibilities within the available ranges as well as the voltage magnitude of the reference node:

- activated generation flexibility ($\Delta P_i^G, \Delta Q_i^G\ \forall i \in N_G$)
- activated load flexibility ($\Delta P_k^L, \Delta Q_k^L\ \forall\, k \in N_L$)
- variation of Compensator Reactive Power ($\Delta Q_c^{cond}\ \forall c \in N_c$)
- variation of OLTC positions ($\Delta tap_{ij}^t\ \forall t \in N_T$)

In addition to the decision variables, the voltage magnitudes and angles in all nodes except the slack are considered state variables. The optimization problem is subjected to the typical Optimal Power Flow constraints [29], as reported bellow.

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$$(\Delta P_n^G + P_n^G) - (\Delta P_n^L + P_n^L) - P_n = 0, \forall n \in N \quad (6)$$

$$(\Delta Q_n^G + Q_n^G) + (\Delta Q_n^{cond} + Q_n^{cond}) - (\Delta Q_n^L + Q_n^L) - Q_n = 0 , \forall n \in N \quad (7)$$

$$V_{n,min} \leq |V_n| \leq V_{n,max} , \forall n \in N \quad (8)$$

$$\theta_{ref} = 0 \quad (9)$$

$$Q_n^{cond} \in \{Q_n^{cond}\}, \forall n \in N_c \quad (10)$$

$$tap_{ij}^t \in \{tap_{ij}^t\}, \forall t \in N_T \quad (11)$$

$$\left|S_{ij}^b\right|^2 \leq (S_{max}^b)^2, \forall b \in B \quad (12)$$

$$\left|S_{ji}^b\right|^2 \leq (S_{max}^b)^2, \forall b \in B \quad (13)$$

where

$$P_n = |V_n| \sum_{k=1}^{N} [|V_k|(G_{nk} * \cos\theta_{nk} + B_{nk} * \sin\theta_{nk})] \quad (14)$$

$$Q_n = |V_n| \sum_{k=1}^{N} [|V_k|(G_{nk} * \sin\theta_{nk} - B_{nk} * \cos\theta_{nk})] \quad (15)$$

ΔP_n^G, $\Delta Q_n^G, \Delta P_n^L$, $\Delta Q_n^L , \Delta Q_n^{cond}$ correspond to the activated active and reactive power flexibility in node *n*.

P_n^G, Q_n^G, P_n^L, Q_n^L, Q_n^{cond} represent the operating point that results from the market-clearing mechanism, the DSO DRES and the net-load forecasts.

P_n and Q_n are the active and reactive flows in node *n* coming from the network branches.

Equality constraints (6) and (7) illustrate the active and reactive power balance. Equation (8) is the inequality that establishes the voltage magnitude limits while (9) defines the voltage angle at the reference bus. In (10) and (11), the discrete sets associated to capacitor banks steps and OLTC positions are modeled. Inequalities (12) and (13) refer to the direct and inverse branch flows limits.

Since the methodology presented in this paper considers the flexibility provided by market agents (such as aggregators), the maximum cost (C_{max}) that the user is willing to pay to use it, should be included in the problem formulation as well as the flexibility band limits of each resource.

$$\Delta P_{i,min}^G \leq \Delta P_i^G \leq \Delta P_{i,max}^G \ \forall i \in N_G \quad (16)$$

$$\Delta Q_{i,min}^G \leq \Delta Q_i^G \leq \Delta Q_{i,max}^G \ \forall i \in N_G \quad (17)$$

$$\Delta P_{k,min}^L \leq \Delta P_k^L \leq \Delta P_{k,max}^L \ \forall k \in N_L \quad (18)$$

$$\Delta Q_{k,min}^L \leq \Delta Q_k^L \leq \Delta Q_{k,max}^L \ \forall k \in N_L \quad (19)$$

$$\Delta Q_{c,min}^{cond} \leq \Delta Q_c^{cond} \leq \Delta Q_{c,max}^{cond} \ \forall c \in N_c \quad (20)$$

$$Cost_{GenFlex} + Cost_{LoadFlex} + Cost_{OLTC} + Cost_{RC} \leq C_{max} \quad (21)$$

As mentioned before, this optimization problem follows the basic concepts of the OPF. Therefore, a class of the interior point methods is used to solve it – the primal-dual [30]. Its choice is mainly related with the robust characteristics that shows when applied to non-convex problems and, in particular, to the OPF [31]. Although it does not mathematically ensure that the global optimum is found for this type of problems, this method already showed a good trade-off between optimality and computational performance. An application to the optimal reactive dispatch problem is described in [32] and the main features that make this method an attractive approach are described. In another work, robustness improvements are presented by a primal-dual method based on multiple centrality corrections [33]. Moreover, the mentioned drawback regarding the global optimum search is shared by every optimization method, whether they are classical or based on artificial intelligence techniques. The choice of the optimization algorithm is a necessary yet not crucial step of the proposed methodology since its real novelty is the capability to explore the entire flexibility area perimeter through an adaptive OPF-based problem. Considering the above, there are significant reasons that justify using the primal-dual method. However, other techniques such as the convex relaxation of OPF [34] or the hybrid PSO described in [35] can be applied to the flexibility area identification procedure without affecting its main goal.

B. Flexibility area identification procedure

In order to estimate the flexibility area at the TSO-DSO connection points, the following steps are carried:

1. Determine the minimum and maximum values P_{min} and P_{max} of $P_{TSO-DSO}$ as well as the corresponding reactive power ($\theta = \pm 90°$, so $\alpha = \pm 1$ and $\beta = 0$).

2. Determine the minimum and maximum values Q_{min} and Q_{max} of $Q_{TSO-DSO}$ as well as the corresponding active power ($\theta = 0°$ and $\theta = 180°$, so $\alpha = 0$ and $\beta = \pm 1$).

3. Perform the optimization for $\theta = \pm 45°$ ($\alpha = \pm 1$ and $\beta = \pm 1$) to obtain four new points of the perimeter of the flexibility area.

The result of this first stage of the optimization procedure is a set of eight points of the perimeter of the flexibility area, offering an idea of its shape. Within these eight points, the first four define the upper and the lower limits of the flexibility area. Then, the methodology enters in a closed loop that will stop only when the defined convergence criteria is reached.

4. For each two consecutive points, if the convergence criteria is not met, perform an optimization for $Q_{TSO-DSO} = 0.5 \times (Q_i + Q_{i+1})$. $\beta = 0$ and $\alpha = 1$ if the two consecutive points belong to the lower part of the perimeter or $\alpha = -1$ when the two points belong to the upper part. The lower and upper parts are defined with respect to active power.

The procedure stops when the exploration of the space between each couple of consecutive points will no longer lead to variations in the flexibility area shape. The convergence criteria used in this paper is based on the Euclidean distance

between two consecutive points and the difference of the corresponding reactive power values. The tolerance parameters depend on the ranges of active power ($P_{max} - P_{min}$) and reactive power ($Q_{max} - Q_{min}$).
The space between two consecutive points needs to be explored in order to find a new point only if:

$$\left(\frac{P_i - P_{i+1}}{P_{max} - P_{min}}\right)^2 + \left(\frac{Q_i - Q_{i+1}}{Q_{max} - Q_{min}}\right)^2 > \delta^2 \quad (22)$$

and:

$$\left|\frac{Q_i - Q_{i+1}}{Q_{max} - Q_{min}}\right| > \varepsilon \quad (23)$$

This convergence procedure avoids searching for points that do not contribute to significant changes in the flexibility area shape. $\delta = 0.6$ and $\varepsilon = 0.25$ are the tolerance values used in the case studies detailed in Section IV. Fig. 4 summarizes the steps of the methodology just described.

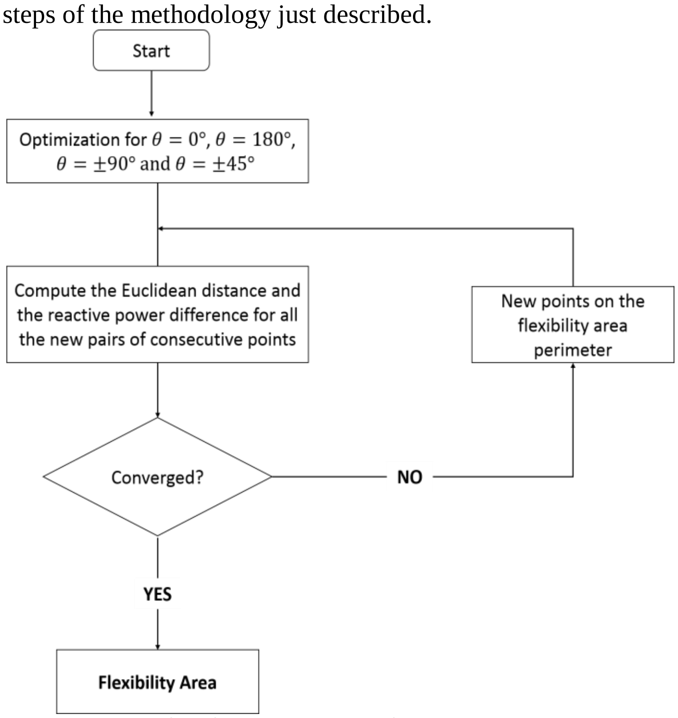

Fig. 4. Flowchart of the flexibility area identification procedure.

IV. Case Studies

A. Description

The effectiveness of the proposed methodology was tested using a MV distribution network whose data were provided by the French DSO. It is a typical urban network with a total of 861 nodes and 5 OLTC transformers connected to two 63/20 kV primary substations. Moreover, this distribution grid is composed of 577 MV/LV substations and 106 MV customers corresponding to a total amount of 62 and 34 MVA, respectively. Regarding the available flexible resources, in addition to the OLTCs, there are five capacitor banks (2 units of 1.8 Mvar and 3 units of 4.8 Mvar) located at the secondary side of the transformers and the following MV distributed generators: one cogeneration unit and two PV units with 1 MW, 1.3 MW and 4.2 MW of installed capacity.

In addition to the network topology and respective technical data, the French DSO provided load and DRES forecasts as well as the current status of grid's equipment (e.g. OLTCs).

Several scenarios considering different types or usage of the available flexible resources could be considered. However, some of these resources (those provided by third parties) are nowadays not accessible for DSO use due to the current French regulatory framework. But, to obtain the most representative scenario as well as to anticipate future network codes, all the flexible resources were considered available. Moreover, if the technical and cost constraints allow it, these resources will contribute with their entire flexibility potential (e.g. curtailing 100% of the forecasted DRES active power injection). Table I gives some details about the available flexible resources.

Table I
Flexible Resources Details

Asset	Action
OLTC	TAP change
Capacitor Bank	Section switch
PV	Active Power Curtail Reactive Power Control
Cogeneration	Active Power Curtail Reactive Power Control

In order to evaluate the methodology capability to consider the maximum cost that the user (e.g., TSO) is willing to pay for the flexibility activation, four different C_{max} were defined. Their computation was based on the flexibility costs associated with each different resource, which, due to confidential reasons, cannot be shown.

B. Benchmark Model: Random Sampling

The quality of the flexibility area estimation is compared with a benchmark model, adopting a random sampling (RS) approach. This technique consists of running multiple power flows with different samples taken from the flexibility band of each flexible resource [22]. Each power flow calculation estimates an operating point, which is considered feasible and included in the flexibility area if the technical and contractual constraints of the distribution network are respected.

This RS approach presents a significant gap related with the capability to find the extreme values of power injection. In fact, the load and DRES flexibilities activated in each node are independently created using uniform distributions. Therefore, the probability distribution of the injected power in the TSO-DSO boundary node is no longer uniform, which explains the absence of the extreme values.
Another limitation of the RS is the high computational effort required. Within the extracted samples, there is no control regarding their feasibility. Therefore, to capture a representative approximation of the flexibility area, a high number of samples is required.

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C. Flexibility Maps

Fig. 5 shows the flexibility cost maps obtained for the network and specifications referred above. The two flexibility maps correspond to two parts of the network (a and b) connected to different primary substations for reconfiguration purposes. Due to the four different C_{max} defined, the methodology described in Section III was run eight times to estimate the flexibility areas in both primary substations. These results concern to a specific time instant of the forecast horizon.

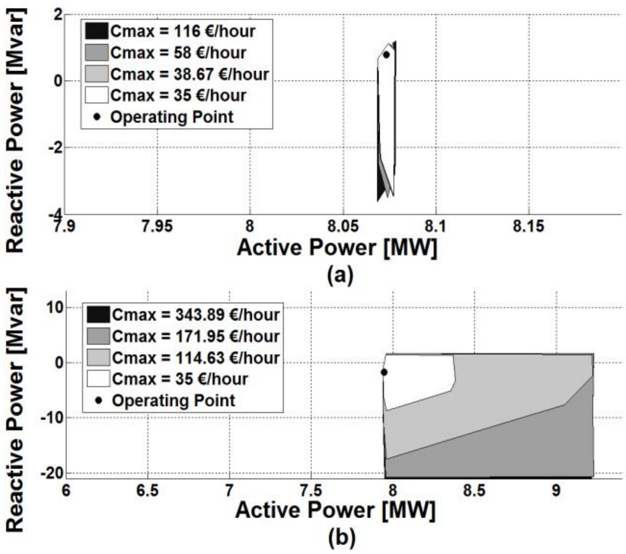

Fig. 5. Flexibility Cost Maps for two sub-networks, a) and b). The former displays almost no active power flexibility when compared to the latter.

As shown in Fig. 5, the two sub-networks present different flexibility ranges. The first one has only reactive flexibility due to the presence of capacitor banks and OLTC transformers (Fig. 5a). The small range of active power variation is related to the effect of the OLTC transformers and their impact on voltage magnitude and losses. The similarity between the flexibility areas with different C_{max} is explained by the technical limits that constrain the provision of flexibility. In fact, there is additional flexibility available in the distribution network however only a part of it can be activated due to technical limits. The network whose flexibility areas are presented in Fig. 5b shows more active power flexibility because it contains DRES whose active power injection can be curtailed in addition to OLTC transformers and capacitor banks.

The methodology fulfils its goals by providing the aggregated active and reactive power flexibility available at the TSO-DSO boundary nodes while considering the technical constraints and the different maximum costs.

The performance of the proposed procedure was compared to the RS benchmark model using two performance indicators: *size of the estimated flexibility area* and *computational time*. The RS was run considering 1000, 10 000 and 100 000 samples (i.e. number of power flow scenarios following a random selection of the flexibility activated in each resource). Table II shows the gains, in incremental terms, of the new methodology when compared with a RS approach.

TABLE II[A]
COMPARISON OF THE RESULTS WITH THE RS FOR EACH SUB-NETWORK

	Flexibility area increase (% of area)			Computational time reduction (% of time)		
	1 000 samples	10 000 samples	100 000 samples	1 000 samples	10 000 samples	100 000 samples
a	54.92	22.51	8.36	79.78	97.88	99.78
b	306.01	130.33	84.79	77.56	97.75	99.76

As shown in Table II, the proposed methodology is able to identify a greater flexibility area with less computational effort. This comparison refers only to the maximum flexibility area of each sub-network, since the results for other areas of the flexibility map lead to similar conclusions. The computational time reduction was obtained through the solution times presented on Table III.

TABLE III
RS AND ICPF COMPUTATIONAL TIMES

	Computational time (s)			
	1 000 samples	10 000 samples	100 000 samples	ICPF
a	6.69	63.79	614.73	1.35
b	13.06	130.24	1221	2.93

The gains illustrated by Table II are linked with the capability to fully estimate the contribution of each flexible resource for the flexibility areas. As already mentioned in this paper, the RS process limits the estimation of the flexibility area zones associated with extreme values of power injection. The ICPF algorithm overcomes these limitations allowing the user to have a detailed and complete view of the flexibility that can be activated in the distribution network. Moreover, the computational time efficiency shown by the ICPF allows the network operators to estimate the flexibility range near real time, therefore reducing the forecast errors impact.

V. DISCUSSION

A. Lessons learnt from field-tests

Field-tests with the proposed methodology were conducted for several months by Enedis (the DSO in France) in order to evaluate the tool performance in a real operational environment. The tests focused on two networks, connected upstream to the national transmission grid (operated by the TSO, RTE); one of these networks is similar to the case presented above. Three different aspects were weighted: expected output, fulfillment of network operation time constraints (non-functional requirements) and integration with the DSO operational systems. The field-tests validated the tool effectiveness regarding the first two aspects, as confirmed by the results presented in Section IV. The application of the new methodology in such real environment constituted a valuable experience to understand how this approach can be smoothly integrated with the DSO operational tools (e.g., SCADA/DMS, forecasting systems) allowing the operator to visualize the flexibility maps for the following hours.

[A] The RS and ICPF tests were performed in a computer with the following characteristics: OS: Windows 7 Enterprise (64 bit), 8 GB of memory, Intel® Core™ i7-2600 CPU @ 3.40 GHz

The real-world implementation also highlighted some new development that should be considered in a future work to enhance the overall performance of the methodology. One of them is associated with the inclusion, as input, of planned maintenance actions since they may cause a change in the network topology. Moreover, the multi-temporal nature of some DER (e.g. charging/discharging features of storage devices) should be taken into account. Regarding its implementation, use of the Common Information Model (CIM) standard should also be considered to normalize data exchanges with the tool.

B. *Benefits*

The awareness of the flexibility area produces an interesting set of benefits for both TSO and DSO. It provides them knowledge about the degrees of flexibility in operation decisions, regarding primary substations when taking advantage of the available flexible resources in the distribution network - without violating the technical constraints and the maximum costs. This information is crucial to support coordinated flexibility activation procedures between DSO and TSO. Without it, if the network state changes at a specific time instant forcing the DSO to activate DER flexibility, the TSO would not know that the margins to change the operating point at the interface would be tighter. This could potentially lead to an unfeasible request of DER flexibility by the TSO. Then, the methodology, by providing the forecasted active and reactive operating point, helps the TSO to accurately forecast the power exchanges in the transmission network nodes, without the need to have the knowledge of the distribution network topology (or of an equivalent). In another context (i.e., operational domain), the flexibility area supports the network planner in assessing the impact of additional flexible resources to the flexibility increase. To draw this conclusion, the approach needs to be run two times: considering and not considering those flexible resources. If any change is observed in the flexibility area, the network planner knows that some constraint is avoiding the flexibility activation. This might indicate that potential network reinforcements are needed in order to profit from those flexible resources. A similar type of assessment can be performed to understand if the current flexible resources potential is being fully explored or constrained by the network.

The outcome is also responsible for enhancing the accuracy in the definition of contractual values of electrical energy exchange between transmission and distribution systems. This effect is a result of combining the areas of feasible operating points and the corresponding maximum costs. By constraining the problem to several maximum costs, both TSO and DSO can access which would be the minimum cost to achieve a specific power exchange at their interface. Moreover, in addition to the cost constraint, this methodology is capable of separating the contributions of each type of flexible resource (i.e., areas of the map divided by type of resource).

C. *Limitations and further research directions*

The approach provides a flexibility map for an individual primary substation. In case of meshed distribution networks with multiple connections to the transmission network, the proposed methodology can be applied to one primary substation only if the active and reactive power flows remain unchanged in the other substations. To overcome this limitation, the method will require the modelling and integration of a network equivalent for the transmission network, in order to estimate the simultaneous flexibility in all the primary substations, while taking into account their mutual dependencies.

The increase in the number of discrete variables with high step lengths (e.g. OLTCs, capacitor banks) may lead to the existence of different disjoint flexibility areas whose envelope is likely to include unfeasible regions. In order to overcome this potential limitation, it seems important to perform a deep inspection of the entire search space. To do so, the development of a metaheuristic algorithm together with a classical optimization approach can be foreseen as the solution to identify all these disjoint flexibility areas that compose the global one.

VI. Conclusions

Thanks to the presence of DER in the distribution level new flexibility levers are or will become available. The estimation of the flexibility available in primary substations (boundary between TSO and DSO systems) is of the utmost importance in terms of added system security and lower operation cost. But, so far, in practice, no handy tool was available for system operators to use.

The paper discusses the performance of a new optimization-based method to provide a practical answer to the flexibility recognition problem – where the concept of distributed flexibility includes the margins of decision offered by aggregators in the electricity market, non-firm connection contracts (e.g., DRES curtailment), as well as OLTCs and the DSO reactive power compensation devices. The method was evaluated in simulation and validated in real field-tests, on MV distribution networks in France. The comparison of simulation results with a random sampling algorithm showed the superiority of the new tool by illustrating its capability to identify a larger flexibility area and to do it within a shorter computing time.

The replicability of the new technique is, in most countries, mainly depending on changes in the regulatory framework that consider a more active role of the DSOs, giving them the ability to provide services to the TSO through a technical management of the flexible resources available in their grids [36].

The real world results confirmed that the new approach provides a step towards a reinforced cooperation between the distribution and transmission network operators, which should lead to improve system security, in a context of increasing penetration of DRES/DER across different voltage levels. This paves the way to a new set of services provided by DSO to TSO, mainly related to technical validation of flexibility and cross-actor exchange of information.

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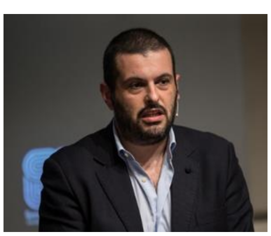

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