Flexibility products and markets: literature review

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Abstract

This paper reviews flexibility products and flexibility markets, currently being discussed or designed to help in the operation of power systems under their evolving environment. This evolution is characterized by the increase of renewable generation and distributed energy resources (including distributed generation, self-consumption, demand response and electric vehicles). The paper is an attempt to review and classify flexibility products considering its main attributes such as scope, purpose, location or provider, and to summarize some of the main approaches to flexibility markets designs and implementations. Main current literature gaps and most promising research lines for future work are also identified.

Keywords; Flexibility markets, renewable generation, distributed generation, distributed energy resources, demand response

1. Introduction

Power systems are undergoing deep transformations towards decarbonized, clean and more efficient energy generation and consumption mechanisms. This changing environment is partially characterized by the following topics:

- Increasing investments in Renewable Generation (RG, mainly wind and solar), located both at the transmission and distribution grids, are changing the net demand (demand minus nondispatchable generation) hourly patterns as well as the consumption patterns.

- RG uncertainty requires stable generation support, increasing reserves and ramping needs from conventional generation, still more adapted to meet these flexibility needs.

- Low variable costs of RG are reducing electricity prices in valley hours, discouraging conventional generation from keeping running, reducing their total operation hours, and making costs recovering harder. However, conventional units are still essential for meeting the demand and providing reserves for the security of supply.

- Current markets are often price-cap energy markets where RG is not fully integrated due to feed-in tariffs. Additional remuneration mechanisms are then needed to incentivize flexible
Increasing Distributed Generation (DG) is posing new challenges to the grids operation. At the transmission grid, balancing and frequency regulation are the main issues, and new flexibility markets to guarantee ramping availability are being implemented. At the distribution grid, reverse power flows, new congestion and voltages issues are appearing, and research seeks to provide new flexibility services to Distributed System Operators (DSOs) to optimize the distribution grid operation and defer investments. DSO tasks are then evolving from long-term planning to include also short-term grid operation, and coordination of Transmission System Operators (TSOs) and DSOs becomes essential for efficient resources usage at both systems.

- Energy Storage Systems (ESS) are expected to gain importance to integrate RG, smoothing prices variability and providing additional reserves and flexibility services.
- Electric Vehicles (EV) are expected to develop, thanks to technological improvements and pollution regulation policies (such as conventional vehicles limitation inside city centers). EVs will increase electricity load, but Vehicle-to-Grid (V2G) mechanisms can help to smooth load profiles and even provide reserve and flexibility services.
- Consumers, more concerned with climate issues and aware of their potential capabilities, are expected to assume much more active roles, investing in Distributed Energy Resources (DER), including DG for domestic generation, Demand Respond (DR) mechanisms to consume in a more clean, efficient and economical way, ESS to integrate DG and contribute to DR, and EV. They are also expected to partially participate in wholesale markets by grouping under aggregators’ agents to overcome market barriers. Concepts like peer-to-peer energy trading are emerging to empower consumers and boost the large-scale adoption of demand-side management technologies.
- Communications and metering improvements, as well as new paradigms such as Smart Grids and Smart Cities, are laying the technological foundations to support the power sector evolution. For example, as an essential part of Smart Cities appear the microgrids as clusters of microgeneration, storage and flexible loads, that act as single controllable entities, able to operate in both grid-connected or island-mode, the later especially fitted for emergencies.

Flexibility needs come from the increasing RG which is giving place to a net load with larger variability and uncertainty, and larger ramping needs, [1], [2]. To date, traditional flexible units (thermal and hydro power plants) connected at the transmission network, have been supplying the net demand and the flexibility needed by means, among others, of intraday and reserves markets, [3], [4]. But as some TSOs argue, [1], [5], [6], [7], the increasing variability and uncertainty are making more difficult to balance generation and load, and flexible units often lack sufficient ramping capability, forcing the use of real time (RT) automatic reserves (such as spinning or frequency containment reserve, [8]), and promoting the design of new flexibility markets. In fact, if enough power and ramping capacity is available in the system, even if the net load could be ramping rapidly, as long as perfectly forecasted, energy only market prices would appropriately reward generators for their flexibility, [9], meaning that uncertainty and no variability is the main cause of flexibility needs.

In addition, DG and EV can make the distribution grid operation more complex, with reverse power flows, congestions, voltages drops and losses (regardless the added complexity of allocating grid costs under this consumption patterns changes). However, smart metering and the potential of DR (both as elastic or load shifting responses) could also provide flexibility
services to the distribution grid, and from the distribution to the transmission grid, with new flexibility usages (distribution grid management, portfolio optimization, etc.).

Flexibility is a general non-standard concept or product, [10], to be procured by different market agents (TSOs, DSOs, Balance Responsible Parties or BRP, see section 2) and expected to be supplied from different types of agents (supply and consumer side agents), located at the transmission or at distribution grids (with different operation problems), which needs to be integrated into the existing markets designed for more traditional power systems, [11]. The literature, while large, tend to focus on particular problems without providing general approaches to flexibility products or markets, being still a matter of research. Indeed, a classification of the different flexibility approaches is needed since they may differ significantly in purposes and implementations.

This paper reviews flexibility products, and classifies and organizes most relevant issues related with flexibility products and flexibility markets. Section 2 introduces the flexibility concept and the main stakeholders involved. Section 3 describes and classifies flexibility products depending on their location and purpose attending at the literature reviewed. Section 4 focus on flexibility metrics, section 5 on market implementations, section 6 on TSO-DSO coordination aspects, and section 7 concludes.

2. Flexibility and Stakeholders

Flexibility is usually defined as the possibility of modifying generation and/or consumption patterns in reaction to an external signal (price or activation signals) to contribute to the power system stability in a cost-effective manner, [12], [13], [14]. Flexibility is usually characterized by the following attributes, [15], [11], [13], [16], [17]:

- Amount of power modulation
- Duration
- Rate of change
- Response time
- Location (transmission or distribution grids node)

Other additional attributes are also mentioned frequently, [17], [11], [15]:

- Delivering time
- Time availability (for example limited for EVs to the plugged-in periods)
- Predictably
- Controllability
- Purpose, such as market players portfolio optimization, or balancing and constraints management in the transmission or distribution grids (congestion relief, voltages drops, loss minimization, component life extension and grid reinforcement deferrals), [15], [18].

While the above attributes are very general so as to deal with most kind of energy or power products, the literature refers mainly to three distinct flexibility products:

- Ramping capacity (power), demanded by TSOs to face the increasing uncertainty of the net demand, [6], [7], [1]. Reference [1] emphasizes the difference with traditional reserves, arguing that these new flexibility products are traded in markets closer to RT, complementing traditional dispatches with fast ramping responses of the flexible units, but without blocking generation capacity as reserves do. TSOs often assume that this ramping capacity must be provided by conventional generation units (since these units can more easily guarantee their declared up and down ramping rates), although more academic
approaches propose more heterogeneous providers, such as EV in [19].

- **Energy**: at the distribution network, flexibility products are more oriented to energy modulation for peak shaving and grid usage optimization, to face the increasing demand and reverse flows, and defer grid investments. Strict ramping constraints (that seem more difficult to be fulfilled by DG or DR, with asymmetric up and down ramping features and still less controllability) are not commonly required.

- **Capacity**: in this case the objective is a long term matching of generation and load, but making efficient use of DER resources. For example, the French TSO proposes in [20] long term capacity contracts to address the increasing peak demand (see section 3.B).

The main stakeholders involved in flexibility markets are ([21], [22], [23]):

- **TSO**, [21]: responsible for the operation of the transmission system and its stability.
- **DSO**, [21]: responsible for the operation of the distribution system and power delivery to customers.
- **BRP**, [21], [24]: market entity (wholesale supplier or retailer, etc.) or its chosen representative responsible for its imbalances. It has to pay penalties for its deviation from its energy schedules.
- **Aggregator**: act as intermediary between smaller entities (such as consumers) and the market, [11], [21], [22]. In [21] it can provide flexibility services to TSO, DSO and BRP. An aggregator can also be its own BRP, being responsible for its own imbalances, [11].
- **Retailer**, [21]: existing commercial entity buying electrical energy from their associated BRP or directly from the market for its customers.

Flexibility uses can be, among others, [24], [23]:

- **TSO balancing** (power balance for frequency control)
- **TSO and DSO congestion management**
- **TSO and DSO power quality control**, in particular distribution grid voltage control and losses reduction.
- **BRP portfolio (energy) balancing**

### 3. Flexibility products

Flexibility products can be offered to TSO for system flexibility, [25] (power balancing and frequency control, and to a lesser extend congestion management, [14]), and are usually provided by conventional thermal power plants (TPP), hydro power plants (HPP, including pump storage units), zonal interconnections (ZIC, one of the most important balancing resources, limited by the unused lines capacity) or DR of large consumers (LCDR).

Flexibility products can also be offered to DSOs for local balancing, voltages or congestion management (network flexibility, [25]), or to BRPs for portfolio balancing (market flexibility, [25]), by DER providers connected at the distribution grid. Reference [23] characterizes DER flexibility usages, and qualitatively assess their technical potential, as well as the maturity of some country mechanisms for their valorization, considering both system and network flexibilities.

Summarizing, the following flexibility products can be identified (see Fig 1):

a) **Balancing flexibility at the transmission grid**, [1], [1], [6], [7]: flexibility products offered to TSOs for balancing purposes. Although traditionally provided in fully developed markets such as intraday and reserve markets, new products in existing or new markets are being
considered worldwide. For example, new ramping capacity products from the same traditional suppliers are being incorporated into several USA energy and reserve markets, and integrated into their co-optimized dispatches procedures.

b) Balancing flexibility at the distribution grid: [19], [20], [3]: flexibility services for the transmission grid, offered to TSOs for balancing purposes, but provided at the distribution grid by DER providers. TSO-DSO coordination becomes essential so that the services provided to the TSO do not generate additional problems to the DSO distribution grid. New agents and new DSO functions are needed with the corresponding technical and regulatory complexities, and no really mature proposals seem to exist yet.

c) Flexibility for the distribution grid: [17], [21], [24], [18], [11], [26]: flexibility products provided by DERs to DSOs for local balancing, voltage and congestion constraints handling, or losses reduction. Proposals usually combine services to the DSOs as well as balancing services to the TSO, with hints on the coordination between both. However, local market mechanisms for DSOs can have too low liquidity for really being competitive, and no mature proposals seem to exist yet. Moreover, with the evolving and new roles of DSOs, new services for flexibility use (e.g., increase security of supply with unintentional islanding operation under emergency operation [27]) can emerge, and its technical-economic assessment requires additional research.

Fig. 1. Flexibility services for system balancing or distribution grids constraints solving.

A. Balancing flexibility at the transmission grid

In [1], flexibility is proposed by the California ISO in terms of fast ramping capacity (to be supplied in 5 minutes) only provided from the supply side at the transmission grid, to complement the other regulation services. In [1] this product is explained as a last way to account for uncertainty before RT, without allocating larger reserves. Indeed, larger reserves for uncertainties that can be managed before RT locks additional capacity which cannot be dispatched as energy before RT, which could in turn produce larger imbalances, apart from additional reserve payments. Co-optimization of energy, reserves and ramping is used for clearing. Similar ramping capacity markets are also described in [28] for SPP (South West

Reference [2] proposes a metric to compute the available system flexibility (see section 6), and a two-step real-time (RT) robust economic zonal dispatch algorithm. At the first step, generation is dispatched to meet the net load of the immediate time period, and the worst case of the following ones considering their uncertainty. Ramps constraints and inter-zonal tie-line flows limits are taken into account. In the second step, tie-line flows limits are partially relaxed and a deterministic nodal security constrained dispatch is performed for the full system, maintaining the zones ramp capability at the values determined in step 1.

In [30] the authors point out the difficulties in forecasting the load participation in ancillary services, since several factors (e.g., nature of the load, control algorithms, aggregation size) could make difficult to deliver the contracted energy. Therefore, it is important to develop mechanisms that mitigate this problem, and some system operators already have penalty terms for situations with reserve capacity shortage. Future research could lead to new concepts such as stochastic market-clearing algorithms accepting probabilistic flexibility offers [31], or the integration, in power system security of supply studies, of the DR capacity according to the seasonality of the electric energy consumption and unplanned unavailability [32].

B. Balancing flexibility at the distribution grid

Reference [19] proposes the use of EV to provide flexibility ramping in markets such as those described in [1] or [7] at the Real Time Dispatch (RTD). They compute the EV aggregated power capacity using Markov models based on the stochastic driving behavior, taking into account factors such as traffic information, accessibility to charging infrastructure, human’s charging preferences, etc. Flexible capacity and final delivered energy (if any) are both payed. EV participation is analyzed as standalone aggregated EV flexibility providers, or by cooperating with traditional generators to improve their ramp capabilities. In the first case, an economic dispatch of the running generation units is complemented with the net EV power exchange to supply the net demand, without commitments decisions and without regulation reserves constraints. In the second case, this dispatch is modified to model that EV ramps are used only until the generators catch up with the new generation set point.

The French TSO RTE proposes in [20] long term capacity contracts to address the increasing peak power demand and to promote investments in generation and DR (by July 2014 all markets should be open to DR participation, with aggregators representing small consumers). This capacity market is to trade capacity certificates, so suppliers’ capacity obligations reflect the contribution of their customers to reduce their consumption at peak periods. Consumers with no consumption have no capacity obligation. Peak days are determined one day ahead by RTE but peak periods take place at fixed day hours.

Four dimensions where efforts for increasing flexibility incorporation (from DER, investment in network capacity and traditional controllable generators) are needed, are reported in [3]: infrastructures (new producers, grid bi-directionality, congestion in distribution grids and closer cooperation between DSOs and TSOs), geographic dimension (better and more global congestions management, more harmonization of market clearing and transmission regulation, nodal pricing to improve congestion management, development of long-distance transmission corridors), interfaces with other energy carriers (decarbonization, electrification of transport and heating, development of technologies such as power-to-gas) and time scale (market gate closures and congestions management closer to RT, capacity mechanisms for
controllable power generators investments but considering its geographic dimension impact). They also point out the changing roles of current actors: generation companies providing energy-related services, consumers becoming prosumers, TSOs regulated by national laws while the nature of power flows is increasingly international (with the complexity of costs networks usage allocation), or the DSOs evolving from their traditional passive role to DG and EV integrators and distribution network operators.

Reference [33] proposes an optimization model for a load aggregator participating simultaneously in the wholesale power market and the tertiary regulation capacity market, in the context of the Nordic power market. The model is a deterministic mixed integer linear programming problem to minimize the total portfolio cost by allocating consumer flexibility among markets. Although the resources managed by the aggregator are located at the distribution grid, no mention on TSO-DSO coordination is done.

An economic dispatch of loads, DG and ESS in a microgrid, with flexibility constraints established by the TSO in terms of intra and inter hour maximum variability, is proposed in [34], as opposed to price-based dispatch. Microgrid loads are classified as fixed and adjustable (responsive to price or controlling signals), so only adjustable loads, dispatchable DG and ESS can provide flexibility. This dispatch implies additional cost for the microgrid that should be compensated by the TSO to incentivize these flexibility services, although no trading mechanisms are proposed.

Finally [35] proposes a deterministic unit commitment with RES generation with limited predictability and endogenous probabilistic secondary and tertiary reserves, where partially controllable residential DR resources can also provide system reserves if comfort constraints are not violated.

C. Flexibility for the distribution grid

In [17] (from iPpower consortium), DER are managed by aggregators that sell flexibility services to the TSO, based on the already existing ancillary services, and to DSOs and BRPs based on new flexibility products in a new market place. Special emphasis on describing the DSO needs, something less reported in the literature, is done (see also [36]):

- Feeder overload (when the feeders security margin goes below 30%) caused by demand growth, regulation services located at the distribution grid activated by the TSO (requiring a strong TSO-DSO coordination), or demand responding to very low electricity prices. Solutions could be products such as Planned or Urgent Power cut, Power Cap (guarantee that a capacity limit specified by the DSO will not be violated) or Power Max (the aggregator guarantees that his local portfolio will not exceed a predefined power). In addition, the product Power Reserve could allow to use this 30% grid security margin by buying flexibility services to low the load in case of emergency.

- Feeder voltages (to keep a proper voltage band, e.g. ±10%), solved with products such as Voltage Support (aggregators have to ensure these voltages will not go beyond the limits), or Var Support (aggregators cooperate with the reactive power control of DSOs). They also propose the use of a Flexibility Clearing House, FLECH, [36], [37], where DSO (and even TSO) would act as buyers of the flexibility services offered by the aggregators, setting their maximum prices based on the reinforcement costs to be deferred, and using standardized contracts on a year ahead basis. The flexibility products that the DSO can contract are described in detail and characterized, among other, by the product type (load or voltage management), the amounts of power and energy, the maximum allowed activation time, the maximum duration
of the service per activation, the location, the on and off triggering conditions, service quality constraints and failures penalties, etc. In [36] three trading products are described: bilateral contracts, auctions (DSOs request flexibility services and the aggregators submit the corresponding bids) and the supermarket (the aggregators offer priced services, and the DSOs are the consumers willing to select their favorite products).

The main aspects related to the TSO-DSO coordination are outlined in [21], based on prioritizing the different uses TSO and DSO may give to the flexibility products. They propose a prioritized list of needs to account for how services affect each other and system stability (see section 6).

In [24] it is pointed out the need for coordination to ensure that a flexibility bid can only be activated if it does not cause problems in either the grid it is connected to, or in grids that might be influenced. Indeed, flexibility options affect TSOs and DSOs, but also generators, customers and loads, prosumers and storage operators, and suppliers and aggregators that offer them, so all of these parties should have access to the data exchanged by TSOs and DSOs they may need, as well as provide their own to the operators. In particular, DSOs should receive relevant data to assess the impact of activation of balancing services and other flexibilities on their grid, so if potential constraints are identified, make the aggregator, BRP or TSO aware. In this sense, they propose a coherent data exchange framework by encompassing all DSOs within a TSO’s control area.

Reference [18] proposes the use of local markets so that the DSO can use the flexibility available from prosumers (including generation, storage devices, and electric vehicles), to maintain the stability and security of the distribution network at minimum cost. These local markets clear the local flexibility bids that are sent to the wholesale market, so that if accepted, result in no local grid issues (see section 5).

In [11], the aggregation of demand-side flexibility services is seen as necessary to allow small customers to provide this type of services for both the transmission and distribution networks, and the main aggregator tasks are reviewed. The authors anticipate the need for local flexibility services provision in local markets distribution grids, with the possibility of exporting to the rest of the system. They review the cases of five existing aggregators in France (3), UK (1) and USA (1), offering flexibility services from small and large customers in traditional balance and reserve markets, with the particularly interesting case of Delaware University, offering to PJM TSO regulating services from a fleet of EV own by a research project. Finally, the main barriers for the development of aggregators, namely lack of smart metering and unadapted markets (minimum bidding volume and bid duration, market entry barriers, lack of DR performance criteria, inexistent local flexibility markets) are pointed out.

Reference [26] proposes an aggregation system for managing and bidding flexibility services from the point of view of the aggregator, when these services are provided by commercial and industrial sites with ESS in the flexibility portfolio. Although not detailed, they propose the use of Mixed Integer Linear Programming problems where the main decision variables are the flexibility activation start times and durations, with different objective functions such as maximizing the expected revenue (using the expected market price), maximizing the bid duration (to provide a minimum amount of power for the longest period possible), or maximizing the peak power (for a particular start time and a desired bid duration). Tests made in a real experimental platform are reported.

Reference [14] reflects the point of view of DSOs and points out that flexibility services for
voltage control and congestion management could provide important benefits such as optimized distribution network capacity investments, reduced losses, reduced DG curtailment and increase DG hosting capacity. It is important to emphasize that the range of flexibility-based services for DSO can be extended, and additional research is need to identify use cases where flexibility from demand and generation side can result in tangible benefits for DSO.

Reference [38] and [39] proposes power flow based algorithms to estimate the flexibility range in each primary substation node for the next hours, to inform the TSO about the feasible flexibility resources available at the distribution grid, based on flexibility actions such as DR, flexible DG, or reactive power control from the DSO assets. The cost of activating these flexibility resources is also considered so that both TSO and DSO can perform a cost-benefit evaluation of the available actions. This information contributes to increase the amount of information exchange between TSO and DSO in terms of technical management of flexibility activation.

In [40], a DSO tool for short-term Active Network Management (AMN) is described. Assuming that the market mechanisms to procure flexibility services to the DSO are already in place, the tool identifies violated network constraints with a classic power flow analysis (assuming a single-phase equivalent grid), and applies an economic analysis to assess the possible DSO actions (assessing independently active and reactive resources since they serve different purposes), followed by a techno-economic robust optimization to determine DSO actions. DSO possible actions include conventional resources grid management as well as DER management, including on-load tap changers, capacitor banks for reactive power compensation, DG reactive power compensation, ESS, Combined Heat and Power (CHP), DG curtailment, and DR. Reference [41] also formulates a detailed ANM problem considering uncertainty in a Markov decision process, with special emphasis on the comparison of solution techniques on three different grids.

In [42] the authors point out that flexibility demand for the system balance is basically independent of the geographical location of the resource, but services provided at the grids are limited to the resources connected at each grid. To defer grid enhancements or investments, they propose that DSO use services provided at the distribution grid, and propose a concrete local market implementation for trading these services based on an optimal power flow.

Reference [10] deals with RES nodes aggregation for flexibility provision. Larger disaggregation allows to provide better services to DSOs to solve local grid problems, but increases aggregator forecasting errors and thus penalties for non-delivered services. The problem is solved with a two-step procedure: first, an optimization problem minimizing the forecasting error determines the nodes to be aggregated in areas to offer flexibility services; second, nodes branches at the same node with too large forecasting errors are aggregated.

A literature review on flexibility services that EV could provide to DSO to help in congestion and voltage problems solving, is performed in [43]. Market recommendations from technical and economic point of views are also suggested (see section 4).

In [44] a DSO ancillary service for solving distribution LV grids voltage deviations is proposed. A voltage sensitivity analysis provides the zones where the activation of the flexibility offers (active or reactive power modification with a price of activation) could be both economically and technically interesting for the DSO, and heuristic optimization methods are proposed to reduce computational burden. However, no details on how to organize such a
market and its interaction with wholesale markets are provided.

Flexibility at the distribution level is very often proposed to defer reinforcement grid investments. However, reference [45] estimates, for some particular grids configurations with optimal DER investments and power access tariffs in place, that it may no exists any significant economic advantage in limiting DER investments, compared to reinforcing the grid to allow for larger flows.

To conclude, the integration and management of flexibility in distribution grids is being actively covered by several authors at the academic level with new conceptual architectures and tools, but the following challenges remain for future work: a) development and test of grid operational management tools with high technology readiness level and able to capture end-users requirements; b) development of stochastic grid management approaches that include modelling of uncertainty from renewable energy and flexibility availability; c) new conceptual models and tools to support TSO-DSO coordination in flexibility pre-qualification and activation; d) new generation of planning tools that conduct a cost-benefit analysis to determine the optimal mix between traditional network reinforcements and long-term flexibility contracts acquisition (see [46] for a first approach to the problem).

4. Flexibility metrics

At the system level, measuring the flexibility available is important to determine if the system is able to face the flexibility needed due to the uncertainty of the non-controllable generators and loads, so TSOs can redispacth units to meet their estimated needs. Often the metrics are embedded into the clearing algorithms, so no explicit computation of flexibility is performed, as in the co-optimized clearing approaches, [7], [1]. In addition, due to the mathematical complexity, uncertainty is usually considered in a very simplified way, by setting confidence bands.

In [47], they remark that no universal flexibility metric exists, but propose the Effective Ramping Capability (ERC) to measure the flexibility available from conventional plants, as an adaptation of the Equivalent Load Carrying Capability (ELCC, amount by which the system’s load can increase if a particular generator is added to the system to keep the same Loss of Load Expectation or LOLE, [48]). It is based on the Ramping Availability Rate (RAR), [49], which is the probability that a unit will be able to deliver its maximum ramp at any time, determined from historical dispatch data, and thus intended for planning studies.

Reference [50] proposes a very simple flexibility metric consisting on dividing the up ramp of the net load by the available ramping capacity of the system. The latter is computed as the summation of the ramping capacities of each unit based on its production, power and ramp capacities, so when the index exceeds 1 load shedding is needed to balance the system. They apply the metric to 2009 Irish data, and regress the marginal price of the spot market against the flexibility index and other fuel spot prices, noting that the market price does not provide generators with incentives to provide flexibility to the system. Intraday markets could provide better flexibility incentives, since flexible units have advantages over inflexible units in energy markets closer to RT, but no analysis is performed in this sense.

Reference [2] proposes the LORP (Lack of Ramp Probability, similar to the LOLP), to measure the ability of the power system to meet the net load changes in RT. It is based on the probability of meeting the next period expected net load (assumed Gaussian with known mean and standard deviation) from the current generator schedules, their ramp rates, and their minimum and maximum stable outputs, considering also the intertemporal interconnection
imports and exports schedules increments, so that positive import and negative export increments sum up as ramp up capability.

In [51], a unit flexibility is characterized by three metrics, namely the energy, the power and the ramp rate the unit is able to provide. The authors propose a model to represent any generic power unit that can generate, consume and/or store energy and compute the flexibility metrics based on the proposed model. The resulting flexibility can be represented as a volume that includes all the feasible points where the unit can be, and the aggregation of flexibility units provides the overall flexibility of the system.

Another approach can be found in [52] where the flexibility required is computed by statistically bounding the difference of consecutive net load power values for different time steps with an envelope. Integration allows to express these required flexibility as an envelope of energy called energy-based operating reserve requirements. The advantage comes from the fact that flexibility profiles of providers are easier to characterize in terms of energy than in terms of power, in particular those of energy-constrained resources such as ESS, allowing their simultaneous scheduling with conventional resources with limited power output levels.

At the distribution level, flexibility providers are worse characterized, since their behavior depends on weather conditions or customers’ habits or decisions, and metrics proposals depend on the resources purpose. For example, reference [53] proposes a method to estimate the available DG flexibility from RG to provide ancillary services to TSOs. Based on actual and forecasted outputs of DG units, black-box models are propose to fit their expected power output as a function of relevant meteorological parameters. Using this models and time series of the actual and forecasted input meteorological variables, probability distributions for different interval values of the inputs are computed, and from them, the probabilistic capacity of the unit and the probabilistic maximum reactive power it can inject. Then a deterministic algorithm is proposed to compute the flexibility to vary the active or the reactive power output of the distribution network considering the connected units.

Another key aspect related with DR is the demand baseline estimation, which is how the customer’s load would have been in the absence of DR events. Baseline estimation and its comparison with the actual load is the process known as DR measurement and verification, [54], [55]. Baseline estimation is essential to assess the magnitude of the DR resources available and their value for the system, and to design market or customer compensation mechanisms to promote and reward DR behaviors: a too high estimation will entail excessive incentives paid for DR services, while a too low estimation will prevent to detect load reductions, providing no incentives to DR.

In [54], DR events are characterized, two main baseline estimation techniques are briefly reviewed and some examples are provided: 1) day matching, which is based on averaging and correcting (using current day features) demand data from past days chosen from a recent time period, for example between 7 and 60 days, and 2) regression models to represent the customers’ load shapes for any day (some examples are also provided). Reference [55] includes additional details on DR events, and collects basic baseline estimation principles: accuracy, simplicity (easy to understand and to reproduce) and integrity (no incentives to irregular consumptions). It also includes a discussion on baselines estimation procedures for DR assessments purposes, with their description and a comparison of their performance.

5. Flexibility markets design

This section focus on relevant aspects to be considered in the design of flexibility markets,
and on literature proposals following the classification of flexibility products of section 3. Several issues, some already reviewed in this paper, that are relevant for trading flexibility products are:

- Type of flexibility product: ramp or energy (short-term) vs capacity (long-term) markets
- Providers: conventional or new DG or RES providers
- Procurers: TSOs, DSOs or other market agents
- Flexibility needs and metrics
- Global or local markets, liquidity and market power
- TSO-DSO and other participants coordination
- Market gate closing time, delivering time and product time duration

A. Balancing flexibility at the transmission grid

This type of products, usually directly traded in wholesale markets, are more developed in USA markets, where the participation and clearing can be integrated in the existing co-optimization procedures for day-ahead and RTD markets.

For example, in [1] flexible products are traded in MISO as other ancillary services, from day-ahead to RT markets, and are characterized by the ramping capability and costs. In CAISO proposal, [7], suppliers add their ramping specification (ramp and cost) to their list of resources specification, and RTD is extended with the constraints needed to guarantee the system ramping needs from the ramping suppliers. These constraints ensure that the required ramping capability becomes available, but is only used if needed for load following. In other similar markets such of SPP, [28], all dispatchable resources are eligible for providing ramp, but no ramping cost is allowed, and the final energy supplied by ramping is paid at the opportunity marginal ramp cost resulting from the clearing algorithm.

B. Balancing flexibility at the distribution grid

Market proposals to integrate DER for balancing purposes, in combination with already existing balancing markets, are in general less mature and still a matter of research.

In the new French capacity market [20] capacity obligations are assigned to retailers based on the actual consumption of their customers during peak periods. Retailers meet their obligations by certifying the capacity they operate or by purchasing certificates already issued (initially by RTE) to other players. Generators must certify their capacities at least three years before the target delivery year, while demand-side operators can submit requests until the start of the same delivery year.

Reference [56] proposes an RT bid-less market (RTBM) to eliminate the entry barriers for small end-consumers and small-scale DER (having both automatic smart controllers) to provide balancing services to the system. A RTBM price is issued by the TSO every 5 minutes. If there are no balancing needs, the price coincides with the DA spot price. Otherwise, the TSO minimizes the cost of obtaining the extra balancing power by determining the amount of additional power coming from the regulation reserve market and the RTBM and both market prices. The regulation market price is the price of the more expensive regulation bid cleared, while the price of the RTBM price relates with the amount of RTBM power through a forecast of the customer’s response to RT prices, this forecast being critical for an efficient operation of both markets. Optimal price determination is dealt with in [57] at the BPR-household interaction level, where the price-respond behavior of households is modelled with stochastic finite impulse response (FIR) models, and chance constraint programing is used by the BPR to keep limit consumption but keeping prices as close as possible to the original market price.
c. Flexibility for the distribution grid

In reference [18], the local market operator of the local day ahead (DA) and intraday markets (ID) receives energy profiles from suppliers and flexibility offers from aggregators (as separated entities to reduce gaming opportunities), and flexibility requests from DSOs and BRP. It then clears the bids so that, if later accepted in the wholesale energy market, they result in no grid issue in the local distribution grid. In addition, the DSO applies a local RT dispatching mechanism to resolve remaining security network issues, non-solved by the previous DA and ID markets. The DSO set its flexibility volumes and flexibility prices offers for the DA and ID markets and the RT profile management mechanisms with a bi-level problem. The upper-level minimize the cost of procuring flexibility from the market and determines DSO’s bid price to participate in flexibility markets and the volumes to be procured from RT mechanisms, while the two lower-level problems represent the clearing of DA and ID flexibility local markets.

Current barriers for aggregators for flexibility markets are described in [11]:

- Lack of metering devices for reliable RT metering and control
- Markets based on the traditional assumption that generation follows demand, with too strong requirements on minimum volumes and duration,
- Inexistence of local balancing market to support DSOs operation with the corresponding coordination with TSOs.

In [43] market recommendations for EV (and other flexibility sources) provision of flexibility services to DSO, from technical and economical point of views, are reviewed. While technical recommendations limit to a precise description of the flexibility offered, with the attributes collected in section 2, from the economic point of view they suggest that:

- Regulation should consider remunerate or incentivize all services provided by DSOs, such as assessing grid reinforcements or managing flexible resources as alternative solutions.
- Definition of clear DSO roles and responsibilities for the implementation of proactive distribution system, as in [15], where the new DSO role of Distribution Constraints Market Operator for contracting and activating flexibilities at different time frames is defined.
- Flexibility contracting can be either on bilateral or market basis, but an open flexibility platform is needed to reduce transaction costs of individually negotiated bilateral contracts. This platform could be used to trade flexibility products through different markets, with their own rules and requirements, and improve the TSO-DSO cooperation.
- Roll-out of smart meters as the first step to contracting flexibility services. Sub-metering is an additional technology that can promote a more accurate calculation/definition of the baseline scenarios, but it should be outside the DSO domain.
- Reduction of minimum bid sizes and ramping requirements to enable demand-response participation.
- TSO and DSO cooperation and coordination. Cooperation implies mutual agreements for all potential conflicting situations that could define priorities for one over the other depending on the use case. Coordination could rely on the flexibility platform supporting a market properly designed (with economic signals disincentivizing counter-effective offers) or by facilitating information exchange.

In [42], the authors propose a local market distribution grid services that operates only during the so-called yellow phase to solve predicted future problems, while the green phase corresponds to grid safe operation, and the red phase allows the DSO to intervene directly to solve a grid problem. Market participants (loads, generators or storage units aggregated or not) provide short-term (15 minutes) and long-term (12 hours) operation point predictions, while
non-participants provide data for the DSO to predict their operation. In addition, participants provide flexibility offers for the next short-term period, so the DSO predicts the grid state and optimally activate, if necessary, flexibility offers, sending the corresponding activation signals for the units to adjust their operation point. Afterwards long-term operation predictions are exchanged with the DSO that issues a new flexibility needs estimation, allowing the market participants to adjust their flexibility offers. It is assumed that RT measurements and grid control is available, as well as a market platform to handle all processes of the local flexibility market.

Three types of prosumers markets are discussed in [58]: peer-to-peer (decentralized and flexible, from the bottom up, and inspired on sharing economy concepts such as Uber), organized prosumers groups (to aggregate and serve the interests of a group of prosumers such as communities, organizations, etc) and prosumers-to-grid (to aggregate in a microgrid a larger number of prosumers providing main grid or microgrid local services, functioning either connected to the main grid or in islanded mode). Complexity of the control systems, unidirectional flow design of existing grids and wave quality issues, increasing number of hours with supply exceeding demand, tariffs designs, or uncontrolled grid defection process, are some of the technical and economic challenges to be faced. Moreover, pure peer-to-peer trading markets tend to neglect the technical constraints of the distribution grid, which could significantly limit the massive integration of PV and EV in several LV grids.

Finally, not really falling on the current classification, some works recommend unified flexibility markets providing both balancing and distribution grid services. As an example, ENTSOE-E suggests in [59]:

- Consistency between wholesale market prices and retail contracts.
- Avoid exclusive or local markets, so as all types of resources can participate in all markets, allowing them to be aggregated without geographical or other barriers.
- In accordance with the previous points, creation of a unique flexibility market where TSO and DSO could procure balancing and flexibility products.
- TSO and DSO should not be providing the services they procure.
- Evolution of balancing markets to integrate TSO and DSO constraints, and market players balancing.

In summary, the main challenge is to design flexibility markets that serve the requirements of both TSO and DSO and that guarantee an adequate return on investment for new market players. Different models, e.g. separated markets for TSO and DSO, hierarchical and peer-to-peer, have been proposed but most of the proposals mean a radical change in the current regulatory framework. Furthermore, it is important to embed the distribution grid technical constraints in the market clearing process, considering different temporal scopes (e.g., real-time, a priori).

6. TSO, DSO and Market Participants coordination

Electricity services very often compete with one-another within the same level of the grid, but can also compete across the system, [60]. While the former could be locally managed by the DSO in coordination with its consumers, the later requires TSO-DSO coordination so that the activation of the flexiblity products offered to the TSO from the distribution grid do not cause problems to the distribution grid, especially for future large RES penetration scenarios. As pointed out in [60], long term coordination is in fact already taking place and promoted by some administrations with smart grid research programs and TSO-DSO initiatives (for example the European Electricity Grid Initiative). However, although many works deal with TSO-DSO
coordination aspects, most limit to establish very basic principles without providing concrete coordination mechanisms, [23], [60], [13], [59]. Among other aspects, RT time monitoring and TSO-DSO structured data exchange (including available forecasts), quasi RT grid simulation capacities, and increasing automation are key aspects of these TSO-DSO and DSO-customers coordinated operation.

In [60] the recommendations are basically related with the information exchange and can be summarized as follows:

- DER energy measurements and flows forecasts must be provided by DSOs to TSO for being considered in the grid analysis.
- Final DER schedules must be provided from the TSO to DSOs, and DER schedules due to DSO adjustments must be provided to the TSO.
- Energy prices (that could be local in nodal systems) must be provided by the TSO.
- TSO and DSO must communicate the activation of DER services.
- Under emergency operating mode TSO and DSO must coordinate their actions.

Reference [61] analyzes TSO-DSO current coordination in different countries and suggests future improvements or coordinated (regulated oriented) procedures for each of the following identified challenges:

- Congestion of Transmission-Distribution interfaces
- Congestion of transmission lines
- Balancing challenge
- Voltage support (TSO-DSO)
- (Anti-)Islanding, re-synchronization & black-start
- Coordinated protection

ENTSO-E recommends in [59] several key TSO-DSO coordination aspects:

- Clear specifications of TSO and DSO observability needs
- TSO overseeing of any active power action with impact on balancing or on the transmission grid constraints.
- Operational planning and before RT TSO-DSO coordination, definition of DER controllability procedures to identify mutual impact of TSO and DSO flexibility activations in emergency situations, and development of system operation agreements under these emergency situations.
- TSO-DSO coordination for efficient and non-discriminatory usage of DER flexibility.
- Structural data exchanges (demand forecasts, generation forecasts, dynamic data models, single line diagrams of planned network, etc) for planning purposes.

In a later ENTSO-E report [24], TSO-DSO coordinated action are analyzed under the following use cases: congestion management, balancing, use of flexibility, RT control and supervision, and network planning. In the case of flexibility usage, it is pointed out the need of coordination to ensure flexibility bids are activated at most once and do not cause problems anywhere in the grid. Finally EU guidelines with ENTSO-E participation, [62], (still a proposal) establish rules and responsibilities for the TSOs, DSOs and Significant Grid Users (SGUs) coordination and data exchange in operational planning and close to RT operation.

In [21] TSO-DSO coordination is based on categorizing the needs, and establishing priorities when conflicting interests appear. Basically they propose the following set of needs from larger to lower priority:

- Emergency actions, requested by TSO
- Alert actions, TSO and DSO
- Local voltage control, DSO
- Peak-shaving, DSO
- Voltage support, TSO
- MVar bands, DSO
- Frequency control, TSO
- Other ancillary services, TSO
- Imbalance issues, BRP
- Power quality, DSO

The traffic light concept, [13], [15], [25], is a way to regulate the interaction among market participants and network operators, focusing on network flexibility to solve distribution problems only. Three color phases are proposed. At the green phase neither critical network situations nor market restrictions exist, and flexibility is for the benefit of the market only. At the amber phase there is a potential or actual network shortage, so the DSO calls upon the flexibility offered by market participants to remedy the situation. In addition, market agents can use the remaining flexibility for their own benefit. At the red phase the system stability and thus the security of supply are in danger, and the DSO is allowed to take control of market actions, overriding contracts, executing emergency actions or performing direct control over the grid units. Since problems frequently extend to several network areas TSO and DSOs must interact, although detailed interaction procedures are not usually provided.

Moreover, the traffic light concept could be used to support the information exchange between TSO and DSO in terms of flexibility activation. For instance, the DSO could conduct an \textit{a priori} and individual classification of the flexibility resources activation in terms of impact in the grid operating conditions, with green indicating no technical problem when activated, yellow when flexibility can be activated only partially, and red when flexibility cannot be activated due to technical constraints. This concept paves the way for future research related to the classification (traffic light) of flexibility resources in terms of negative impact in the distribution grid, which could influence the merit order of automatic generation control (AGC) signals for DER connected to the distribution grid.

In [63] an interaction scheme for TSO, DSO, producers and retailers is proposed. Prior to day by day operation, each BRP requests to the DSO a power range access to the grid. The DSO computes each BRP safe access range, so that if every BRP is in its safe range no grid congestions can appear. Contracts between BRPs and DSO are then specified with a full access range, where the BRP can operate without any constraint or obligation, and a (wider) flexibility access range, obtained by adding flexibility intervals at each side of the full range, and where the DSO can impose restrictions on the production or consumption if necessary. In addition, since the simultaneous activation of flexibility services from flexibility users can lead to unwanted congestions, in day by day operation, dynamic ranges are used as follows to avoid it: BRPs provide baseline proposals inside their flexibility ranges; based on these baselines, the DSO computes dynamic ranges for each BRP (larger than their full access ranges), so that its network is secure; BRPs submit to the DSO and the TSO new baselines (inside the dynamic ranges) which are used as reference for the provision of flexibility services. If a BRP violates its dynamic range, it is penalized at a regulated tariff higher but of the same order of magnitude than the imbalance price.

In summary, the TSO-DSO coordination problem in terms of flexibility management requires additional developments in the following two areas: a) conceptual model for data exchange and flexibility activation, as well as a suitable information and communication technology (ICT) platform; b) tools and algorithms for joint flexibility management (e.g., hierarchical optimization), and for forecasting and control of active/reactive nodal injections in...
primary substations.

7. Conclusions

This paper presents a literature review on flexibility products and market mechanisms, and classifies the different approaches regarding the purposes of the flexibility products (transmission network balancing and frequency regulation or system flexibility, distribution grid problems solving or network flexibility, or balance responsible parties balancing or market flexibility) and their location (transmission or distribution grids). It also focuses on relevant flexibility aspects such as products definition, metrics, markets design and market agents’ coordination. A summary analysis of this literature review can be found in Table 1, that classifies the main references according to the following attributes: 1) where the flexibility lies (at the distribution grid, DG, the transmission grid, TG, or both) and to which grid it is providing its services (to the distribution grid, DG, to the transmission grid, TG, or both); 2) the type of product being considered: ramp (R), energy (E) or capacity (C); 3) for those documents with advanced proposals or implementation, the country or region for which it has been designed or it is intended to; 4) if it is an academic (A) work or and industrial (I) proposal, and if the document provides an overview on flexibility (Owv), a proposal of a concrete implementation (Prp), corresponds to a real implementation in operation (Op), or is a positioning paper of some industrial entity or institution (Pos); 5) if the paper proposes a concrete dispatch procedure to integrate flexibility products (Yes or No) and if this procedure is an individual optimal schedule (Shc); 6) if distributed flexibility resources are considered (Yes or No), and if special emphasis is made on the aggregators (Agg); 7) if TSO-DSO coordination issues are somehow addressed (Yes or No); 8) if metrics for quantifying the flexibility of a system or of a set of resources are proposed (Yes or No); 9) if it contains market proposals to integrate flexibility resources (Yes or No); and finally, if it contains regulatory proposals to help integrating flexibility resources (Yes or No).
Table 1. Classification of the flexibility references based on the analyzed criteria

System flexibility markets using conventional generation are more mature and appear as
natural extensions of already existing wholesale markets, designed to guarantee system ramping (using almost real time dispatching) while preserving traditional reserves. However, marketing DER flexibility products is still a matter of research, and although many recommendation and guidelines can be found, no real implementations are in place yet. Many important challenges are still to be solved, some of them being:

- It seems necessary to formulate standardized but simple definitions of flexibility products or offers, accounting for energy-constrained resources (such as EV and ESS), to facilitate flexibility management and dispatch at the transmission and distribution level, and to adequate products to its different uses for system, network and market flexibilities. In this context, the following topics deserve further research:
  
  a) Accounting for potential flexibility capacity shortage situations that influence the operating risk of the power system. One possibility is the implementation of probabilistic offers (i.e., quantity, price and risk level) for flexible resources like demand response and RES (whose reserve band also has some associated probability/risk [64]). The literature is going towards this research line through several works on stochastic market-clearing mechanisms. This risk in flexibility shortage, and the seasonal component of some flexible loads (e.g., air conditioning), also requires a revision of methodologies for long-term reserve capacity adequacy studies in order to improve the estimation of classical reliability indexes (e.g., loss of load probability, expected energy not served) under these new conditions.
  
  b) Inclusion of the “rebound effect” of demand response actions (i.e., consumption decrease may be followed by a load increase in a later period) in market-clearing mechanisms. A simple solution could be analogue to complex offers designed to conventional plants in some markets, or the asymmetric block offer from [65].

- Should or could these products be traded in already existing wholesale markets (such as intraday and ancillary services markets as it is in Europe, or integrated in USA-like co-optimization procedures, with the required reforms), or in newly created wholesale or local markets? Most of the works in the literature, as well as at the commercial level, are focused in developing optimization and market bidding tools for traditional wholesale and ancillary services markets. A recent research trend is peer-to-peer energy trading supported by blockchain technology [66], which might create conditions for peer-to-peer trading of flexibility from community storage or demand response flexibility directly between prosumers. The main limitation of local markets, particularly when oriented to support DSO in managing grid technical constraints, is the low liquidity that compromises competition and may allow market power exercise. Alternative frameworks, not yet fully covered in the literature, are: (i) remunerate local flexibility under regulated mechanisms, for instance imposing a cap on the flexibility price that depends on the level of investment deferral associated to the flexibility use; (ii) annual flexibility tenders in coordination with network planning departments; (iii) bilateral contracts between network operators and flexibility providers.

- How should short-term flexibility products be remunerated? For product delivery only, or also for product availability (something probably mandatory for capacity markets)? For technical constraints management, remuneration by product availability might increase considerably the operating costs and make network reinforcement the least costly solution. The challenge is to design attractive remuneration schemes that boost the flexibility potential, but that enables a feasible business case to recover the initial high investment in ICT and new energy assets. A good real-world example is from several system operators in U.S.A that implemented dynamic automatic generation control signal for fast ramping
resources (e.g., battery storage) and introduced a pay-for-performance compensation with three components: a) correlation between control signal and regulating unit’s response; b) time delay between control signal and point of highest correlation from the accuracy score; c) difference in the energy provided versus the energy requested by the regulation signal. A similar scheme could be extended to exploit flexibility in other system services.

- It is necessary to define a set of new system services (i.e., non-frequency control services) for DSO. It is widely assumed that DSO will purchase flexibility for congestion management under scenarios of high integration of DG. However, future research work should focus in cost-benefit analysis of flexibility use for other DSO related tasks, for instance: solving over and under-voltage violations; active power losses minimization; unintentional islanding (emergency operation); phase balancing; support planned and unplanned maintenance operations; contribution to extend assets lifetime. Moreover, some of these services might also require the definition of new flexibility services, like permanent load reduction during a specific period of time or mobile battery storage.

- The definition of an adequate baseline for DR performance assessment and financial settlement is a fundamental requirement for the successful deployment of DR products. Some DR markets in U.S.A. have already implemented rules for baseline calculation. However, an important question for future research is: should the market remunerate DR by comparing its performance with its baseline (estimated by some regulated statistical method), or by comparing it with the previously cleared schedules of the BRP managing this demand (leaving to BRPs the responsibility of baseline estimations)?

- How can TSO and DSO be efficiently coordinated, establishing the required priorities of the flexibility uses and the detailed interaction procedures for their cooperation under different scenarios, especially under emergency situations? In this topic, the challenges for future research are:
  a) Creation of adequate bi-directional data exchange platforms of information about flexibility pre-qualification and activation between TSO and DSO. The European Project SmartNet proposed five different coordination schemes between TSO and DSO with impact in the procurement of ancillary services (frequency control services) and local system services [67], which can be an adequate framework to develop new coordination algorithms and platforms. Moreover, the “amount of flexibility” can be quantified and exchanged with the flexibility maps [39], which require additional research for a better communication/visualization of the embedded information.
  b) Integration of the information about current and short-term distribution grid operating conditions in the selection of flexibility activated by the TSO for frequency control purposes. An interesting research challenge is to cover the following scenarios: (i) ex-ante validation: the DSO assesses in advance if the available frequency control offers are technically viable or if they can create local constraints in the distribution network, and defines different grid status (yellow, red) for the flexibility offers; (ii) pre-activation validation: the TSO communicates to the DSO in advance (e.g., 15 min before) the pre-selected flexibility offers for the next operating period. The DSO conducts a technical validation of the offers and returns a validated activation program, which might include changes in the offers activation in case of technical constraints violation. Nevertheless, this operational validation of flexibility should not exclude a close interaction between TSO and DSO during the pre-qualification of flexibility resources.
  c) A third possibility is to have the DSO managing the distribution grid flexibility like
a technical virtual power plant, where, from the TSO perspective, each transmission network node is a virtual generator that can inject or consume active/reactive power. However, this solution means a radical change of the regulatory framework (e.g., share of costs, benefits and responsibilities between TSO and DSO, market conditions for flexibility contracting by the DSO) and requires modifications in traditional optimal power flow tools.

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