Modelling TSO-DSO coordination: The value of distributed flexible resources to the power system

Hanne Høie Grøttum *, Siri Førsund Bjerland *, Pedro Crespo del Granado*†, Ruud Egging*
*Norwegian University of Science and Technology, Dept. of Industrial Economics and Technology Management
† SINTEF Energi Research, Trondheim, Norway

***Abstract*—The interaction between the transmission and distribution system operators is mainly based on a unidirectional flow of information (transmission-to-distribution system operators). The resources in the distribution systems are, hence, not utilized fully in overall power system operations, regardless that they may serve as sources of flexibility to manage renewable energy sources fluctuations. In the existing literature, is not very clear how the coordination of the transmission and distribution system operators can and should be modelled. Accordingly, there is limited insights to the potential value coordination may bring to the overall power system operations. As a result, this paper presents a modelling approach for coordination of the transmission and distribution system operators, where flexibility is provided by distributed energy resources located in the distribution systems. Key findings suggest that the total costs of power system operations are reduced when distributed flexible resources are incorporated under a joint coordination framework.**

***Index Terms*—Distributed Energy Resources, Renewable Energy, TSO-DSO Coordination Scheme, Aggregator**

I. Introduction

With the high penetration of renewable energy sources (RES), the power system will require to raise a higher amounts of flexibility resources to mitigate the variability of the RES generation. In this regard, distributed energy resources (DER) could play a more prominent role in providing flexibility if they are integrated in current electricity markets and operations, i.e. support the decisions of the transmission system operator (TSO). To accomplish this, the distribution system operators (DSO) will have to transition from a passive to an active role. Active DSO participation in power system operations will rely on establishing a bidirectional flow of information between the transmission and distribution level in the power system.

In this paper, we analyse the value of TSO-DSO coordination in power system operations. To do so, we develop a modelling framework which coordinates the operations of the transmission and distribution systems in a power system with a 30% share of RES and a small number DERs available at the DSO level. The DERs include distributed generation (DG) units, decentralized storage, distributed/local RES (DRES) and demand response (DR). Flexibility can be provided from DG units, decentralized storage as well as DR upon request from the TSO. That is, the objective is to understand: What is the value of TSO-DSO coordination? How does the integration of DERs affect the power system operations? Furthermore, we seek to comprehend the effect of including the different interests of the TSO and DSOs to the problem.

A centralized and a coordinated model are proposed. Both are deterministic mixed-integer linear programs. The first model (named Case I) represents the traditional top-down approach in power system operations. This means that only energy resources located at the transmission level are considered to cover the demand. The second model (named Case II) represents the coordinated problem wherein the DERs also contribute to cover the demand. This model is expanded (Case III) to include a study of the different interests of the TSO and DSOs through the weighted sum method (WSM). The models are applied to a simple test system to illustrate and evaluate the TSO-DSO coordination.

Results show that the DSOs can provide cost-competitive flexibility services. DR programs, distributed storage and other DERs prove crucial to participate in the volumes requested by the TSO. Furthermore, the total costs of the system are reduced by approximately 1 % with a less than 1 % share of DERs in the generation mix. Half of the decrease in costs stems from a reduction in start-ups and shutdowns of conventional generation units.

A. Related literature

The transition from unidirectional to bi-directional flow of information between the TSO and DSO to exploit the available generation capacity in the distribution systems is highlighted in [1]. Furthermore, [2], [3] points out the necessity of models linking these two levels in the power system. This has been addressed in literature to a limited extent to present day.

A selection of possible developments in TSO-DSO coordination is studied in [4]. From the perspective of the TSO, the economically optimal use of DERs such as DR, storage and PV is through flexible units for secondary reserves given the ancillary service scheme rather than redispatch.

In [5] a deterministic hierarchical coordination between the TSO and DSO with dispatchable distributed generation in the distribution system is developed. The information barrier is still present, as the information is packed into generalized bid functions and communicated from the DSO to the TSO. The impact of the coordination is measured through the comparison of the hierarchical and centralized approaches. The authors in [6] extend the coordinated problem to include

This is the accepted version of an article published in 2019 16th International Conference on the European Energy Market - EEM 2019
http://dx.doi.org/10.1109/EEM.2019.8916377

uncertainty in renewable power generation through a two-stage stochastic program with a detailed description of DR as DER. Also, the modelling frameworks in [7] and [8] have DR as the distributed energy resource. [7] develops a robust two-step iterative framework with uncertain market prices whereas in [8] the wind power generation, as in [6], as well as equipment failures are considered uncertain in a robust chance-constrained approach. In our opinion, [8] represents a simplified coordinated system since only the transmission system operations are included, but the TSO is able to take advantage of DR directly.

Although, [5]-[8] consider important aspects of TSO-DSO coordination, the available DERs for flexibility are limited to one technology. Overall, models evaluating the value of TSO-DSO coordination is limited or tend to be one sided (TSO or DSO focused).

B. Contributions and objectives

In this paper, we present an optimization model that considers the coordination of the operations of the TSO and DSOs with flexibility supplied by DERs in the distribution systems. The flexibility is used optimally by minimizing the total cost of power system operations. In order to preserve the information barrier between the TSO and DSO, as they are actors with different interests and no incentive to share all information, the capacity available from DERs is aggregated for each technology in each distribution system. There is still a limited information exchange between the transmission and distribution systems in the coordinated model through the power balance constraints, which includes the power transfer between the two levels. The coordinated model is developed as a deterministic mixed integer linear program.

To provide a benchmark for comparison, an optimization model representing the current top-down approach (TSO only) in the power system is developed for comparison a version of the coordinated model. This model resembles the operation of the power system today. Both models are applied to a simple power system defined and based on IEEE test systems, examples in MATPOWER and general assumptions in literature.

The remaining sections of the article are structured as follows. Section II provides the model formulation. The case study is described in Section III. The results are discussed in Section IV. In Section V we give our concluding remarks.

II. Model formulation

A. Modelling framework

The top-down and coordinated problems are both modelled as deterministic mixed integer linear programs with unit commitment and economic dispatch to optimize the power system operations. The models differ in the level of information exchange between the TSO and DSO. In coordinating transmission and distribution systems, we establish a position for the participation aggregated DERs. The DERs are aggregated to preserve the information barrier between the transmission and distribution levels. Comparing the results of the two models, will allow the evaluation of TSO-DSO coordination.

B. Power flow

The link between the transmission and distribution level may be found in the power balance constraints. The power flow in the transmission system is given by Eqs. (1)-(2), and in the distribution system in Eq. (3).

$$\sum_{g\in\mathcal{G}} p^G_{gtb} + P^{W_C}_t + m^-_{tb} - m^+_{tb} - (1-\gamma)p^L_t = \sum_{a\in\mathcal{A}_b} p^{proc}_{ta} \qquad t\in\mathcal{T}, b=1 \tag{1}$$

$$\sum_{g\in\mathcal{G}} p^G_{gtb} + P^{PV_C}_t + m^-_{tb} - m^+_{tb} + (1-\gamma)p^L_t \geq \sum_{a\in\mathcal{A}_b} p^{proc}_{ta} \qquad t\in\mathcal{T}, b=2 \tag{2}$$

$$p^{proc}_{ta} + p^{DG}_{ta} + n^-_{ta} + P^{W_D}_{ta} + P^{PV_D}_{ta} + p^{DR}_{ta} = P^D_{ta} + n^+_{ta} \qquad t\in\mathcal{T}, a\in\mathcal{A} \tag{3}$$

Eqs. (1) and (2) show the power balance constraints of Case II, where the demand covered by the transmission system is equal to the total load in the distribution systems less the generation from DERs, i.e. p^{proc}_{ta}. In Case I, all load in the distribution systems is covered by the transmission system buses. This means that p^{proc}_{ta} is replaced by P^D_{ta} in Eqs. (1) and (2).

Also, the power balance in each distribution system, Eq. 3, defines the level of the demand that needs to be covered by the transmission system. Since the DERs are not included as generation capacity in Case I, the power balance equations of the distribution systems are not included.

As Eqs. (1) and (2) show, the power balance constraints of the transmission are separated by each bus. That is, because the constraints are defined specifically for the case study for simplicity. Furthermore, at the second transmission system bus (b = 2) the restrictions on power balance is defined as a greater than or equal to constraint because surplus generation is possible but considered a spillage of the production without an associated cost.

C. Objective function

The objective of the top-down approach in Case I is to minimize the total costs of the transmission system in Eq. (4), and it includes fixed, variable, start-up and shutdown costs of centralized generation units p^G_{gtb} as well as the costs of centralized storage discharge m^-_{tb}. Furthermore, the objective of the coordinated model in Case II is defined as the sum of Eqs. (4) and (5) as the aim is to minimize the total costs of the power system, meaning that it is holds the costs of the transmission and distribution systems. The costs of the DERs in the distribution systems are divided into costs of decentralized storage discharge, n^-_{ta}, DR, p^{DR}_{ta}, and decentralized generation units, p^{DG}_{ta}.

This is the accepted version of an article published in 2019 16th International Conference on the European Energy Market - EEM 2019
http://dx.doi.org/10.1109/EEM.2019.8916377

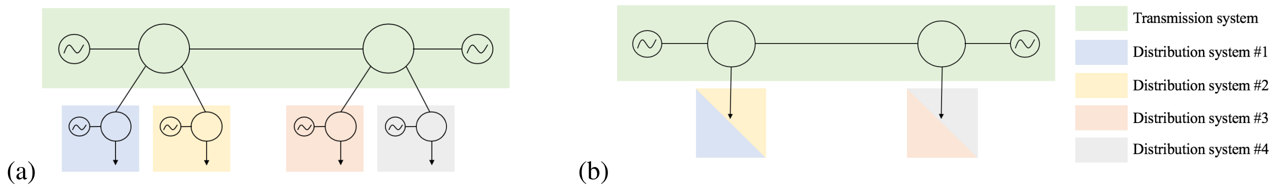

Fig. 1: Power system considered.

$$\sum_{g\in\mathcal{G}}\sum_{t\in\mathcal{T}}\sum_{b\in\mathcal{B}}\Big(F^{G}_{gb}P^{G_{max}}_{gb}x_{gtb}+C^{G}_{gb}p^{G}_{gtb}+C^{SU}_{gb}y_{gtb}$$
$$+C^{SD}_{gb}z_{gtb}\Big)+\sum_{t\in\mathcal{T}}\sum_{b\in\mathcal{B}}C^{M}_{b}m^{-}_{tb} \tag{4}$$

$$\sum_{t\in\mathcal{T}}\sum_{a\in\mathcal{A}}\Big(C^{N}_{a}n^{-}_{ta}+C^{DR}_{a}p^{DR}_{ta}+C^{DG}_{a}p^{DG}_{ta}\Big) \tag{5}$$

The objective of Case III is defined in Eq. (6). In the existing power system, the DSO typically buys power from the transmission grid. This is not fully reflected in the coordinated model, since there are no costs associated with power procurement from the grid. This is because the TSO and DSO are assumed fully cooperative, jointly optimizing the power system operation. The results may be different if the price of procuring power from the grid is added to the model formulation. Consequently, Case III represents this situation, where Case I has been used to calculate the electricity prices of the overall system. The prices are calculated either by dividing the objective value at each time step by the energy production at the same time step or obtaining shadow prices. These prices, multiplied with the power procurement for each distribution system from the transmission system, p^{proc}_{ta}, are added to the objective in Case II. Furthermore, the objectives of the transmission and distribution systems are weighted according to the WSM (features of a multi-objective model) to account for the different interests of the TSO and DSOs, see Eq. 6.

$$w\Big(\text{Eq. (4)}\Big)+\Big(1-w\Big)\Big(\text{Eq. (5)}+\sum_{t\in\mathcal{T}}\sum_{a\in\mathcal{A}}C^{proc}_{t}p^{proc}_{ta}\Big) \tag{6}$$

Additionally, the model includes ramping, up- and down-time constraints for the centralized generation units as well as generation and line capacity restrictions, storage constraints for both centralized and decentralized and limitations on DR. All these constraints follow general conventions, see for example [6], [7] and [9].

III. Case study

The transmission system contains two buses, each connected to two distribution systems represented by buses. The system is illustrated in Figure 1(a). Somewhat different approaches to this system are solved in the three cases:

- Case I: Top-down approach (TSO only).
- Case II: Coordinated TSO-DSO problem.
- Case III: Coordinated TSO-DSO with multi-objective optimization.

In Case I, the power system shown in Figure 1(b) is what the TSO considers. The demands of the distribution systems connected to each transmission system bus are aggregated into one load seen from the transmission system bus. The only power generation capacity considered is found in the transmission system. This is an attempt to represent the current top-down approach typically modelled in the power system literature. The generation capacity connected to the transmission system buses includes centralized power generation such as coal, gas, hydropower power plants, renewables, i.e. wind and solar power, and centralized storage units.

The power system structure in Case II and III differs from Case I as seen in Figure 1 (a) and (b). The four distribution systems are now represented by one bus each. Furthermore, the distribution systems now hold both production capacity and demand, which includes decentralized generation units, like combined heat and power (CHP) and biomass, renewables and storage units as well as demand with related DR. Distribution systems 1-4 are characterized as residential, commercial, industrial and rural areas, respectively. The amount of capacity and demand in each distribution system is set according to this characterization. For example, the rural area is associated with low demand and has enough open land to contain a wind park. The demand patterns for all of the distribution systems are shown in Figure 2. Furthermore, the capacity for generation in the transmission system is as in Case I. This represents the coordinated problem in Figure 1(a), where both the TS- and DS-level are taken into consideration in detail. The difference between Case II and III is the inclusion of prices of power procurement paid by the DSO to the TSO to cover demand.

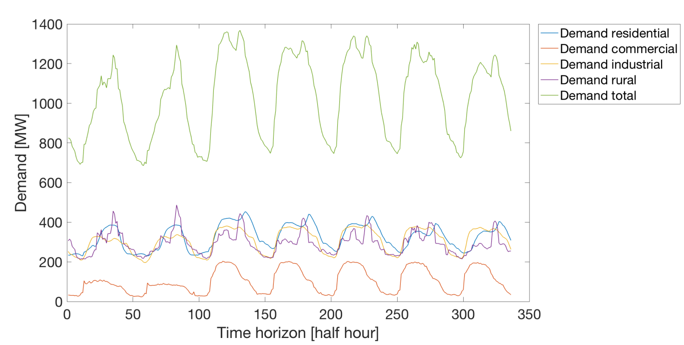

Fig. 2: Demand patterns in the distribution systems.

This is the accepted version of an article published in 2019 16th International Conference on the European Energy Market - EEM 2019
http://dx.doi.org/10.1109/EEM.2019.8916377

All cases are run separately for each day throughout one week in summer (July) and winter (February) of 2015 and 2016, respectively. From that, it is possible to retrieve demonstrative results to draw key insights and conclusions. All cases are run with time steps of half an hour.The models are solved using the toolbox for modelling and optimization YALMIP [10] in MATLAB_R2017b and the MILP-solver GUROBI 8.0.1. MATLAB_R2017b is run in a regular laptop.

IV. Results

A. Costs and distributed energy resources

It is assumed that both the TSO and DSOs are price takers and, consequently, there are no costs associated with buying power from the transmission system for the distribution systems, i.e. there are no costs between the levels (TS and DS) in the power system. Hence, the total costs of operation in Case I and II may be compared without adjustments. In both cases, the system cost in €/MWh is lower in summer, as seen in Table I. That is because the demand is lower in summer and RES output in total is higher with no associated cost. The Table also shows that the system cost in €/MWh for each season is overall lower for Case II. Approximately half of the cost reduction stems from the decrease in start-ups and shutdowns, which is 6 900 € and 10 900 € in summer and winter, respectively.

The share of generation from DERs is below 1% in Case II, see Table II. Despite of the share of DERs being low compared to the share of centralized power generation, the cost reductions from Case I to Case II are significant. By the numbers in Table II, it can be calculated that the savings in operational costs for one week are more than 14 000 €and approximately 20 000 €in summer and winter, respectively. This illustrates the potential of incorporating the distribution systems and consequently the DERs into the power system operations, since the potential cost reductions are high even though the share of DERs is very small.

B. Power generation mix

Figure 3 illustrates the power generation portfolio for the first three days in winter of Case I and II. Note that the plots do not include storage supply (charge) to storage, which is why supply exceeds demand in some time steps.

The nuclear and gas power plants are base load with low variable costs, additionally, it is slow to start up and shut down these units. Consequently, these power plants are close to always active as in Figure 3(a) and (b). Furthermore, biomass is used as a peak load unit in Case I in Figure 3(a). However, the contribution from the biomass power plant is not needed in Case II since the supply from DERs and load shifting in storage is able to cover demand at a lower cost.

With a high power generation from renewables, less supply is needed from the conventional power sources, i.e. coal is shut down occasionally, see Figure 3(a) and (b). Also, coal is preferred to hydro in most time steps. However, in the first day of Case II the hydro power plant is used rather than using coal as in Case I. It appears that since it is preferred to use gas before both coal and hydro due to lower costs, hydro is chosen to supply the remaining demand in Case II. That is, because of the contribution from DERs making it beneficial to use gas as long as possible with some supply from hydro in Case II. While in Case I, supply from coal is needed because of its larger installed capacity than hydro. The coal power plant, then, has to remain on for 8 hours (16 time steps) due to the minimum up-time constraint, which causes the shutdown of gas production.

C. Start-up and shutdown

The number of start-ups and shutdowns of the conventional generation units is lower for Case II, see Figure 3. For example, the biomass power plant has a decrease in both start-ups and shutdowns from four to one in Case II compared to Case I in the winter week. This means that the cost of start-up and shutdown decreases throughout one week from Case I to Case II. That is, because the cost is proportional to the number of start-ups and shutdowns. With fewer start-ups and shutdowns, also the CO_2 emissions in the system may potentially be reduced due to less starting up and shutting down operations.

The power balance constraint in the second bus of the transmission system is an inequality constraint, meaning that there is a possibility of excess supply in the system. The inclusion of DERs in Case II could cover demand so that conventional generators would not have to be started up and, hence, generate more than is in fact needed in the system because of their power generation limits. However, there is no considerable improvement in the efficiency of the operations in Case II due to less surplus power in the system. There is a marginal surplus in Case I during winter, which is suppressed in the coordinated model, but it accounts for only about 0.06% of the total power generation in the system.

D. One step further: Case III

Case II showed the potential of coordinating the transmission and distribution system. The total power system costs decreased by approximately 1%. Case III introduces a cost for the DSO to buy electricity from the TSO. Previous cases were solving a (cost minimization) total system welfare. Case III implements the shadow prices of Case I (TSO only) into Case II. It introduces an hourly pricing for the DSO based on the outcome of the centralized market (TSO).

Case III multi-objective features is run nine times with different weights to examine the sensitivity of the solutions on the weighing coefficients. The weighing coefficient of the TSO objective, w, is 0.1 in the first run, then 0.2, 0.3 and so on up to 0.9. Consequently, the weighing coefficient on the DSOs objective, $(1-w)$, is 0.9 in the first run, 0.8 in the second, and 0.1 in the last. Figure 4 presents all these results. The points are all part of the subset of non-dominated solutions, and, therefore, represent the subset of the Pareto front. Because it is not possible to say which solution is better or worse than

This is the accepted version of an article published in 2019 16th International Conference on the European Energy Market - EEM 2019
http://dx.doi.org/10.1109/EEM.2019.8916377

TABLE I. Costs for Case I and II (one week)

	Case I summer	Case I winter	Case II summer	Case II winter
Objective value [10^6€]	1.6586	1.9797	1.6445	1.9589
Cost [€/MWh]	4.6589	5.0123	4.6210	4.9800

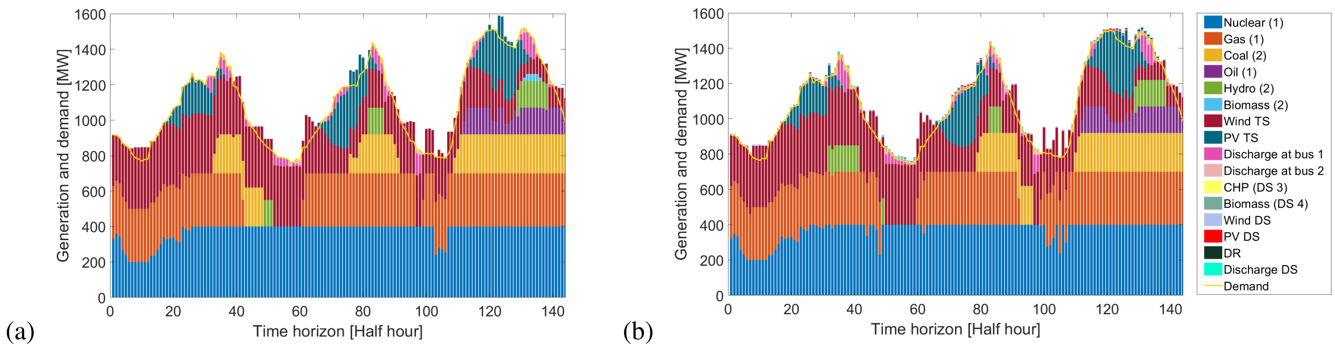

Fig. 3: Overview of power generation and demand in (a) Case I and (b) Case II

TABLE II. Power output and share of total power output for centralized and distributed generation in Case II (one week)

	Power output [MWh]	Share [%]
Summer		
Centralized generation	353 020	99.20
Distributed energy resources	2 859	0.80
Total	355 879	100
Winter		
Centralized generation	390 829	99.36
Distributed energy resources	2 524	0.64
Total	393 353	100

the other, the preferences of the decision maker determines which solution is chosen.

The total costs in the coordinated weighted problem is higher than the original Case II, since the costs of power procurement are included and account for approximately 50% of the total costs. Consequently, to be able to compare the total costs obtained from Case III with those from Case I and II, the costs associated with power procurement from the grid need to be subtracted from the total costs (not weighted) as this cost category does not appear in Case I and II. The resulting total cost of Case III varies from 0.229 million € (when w = 0.2) to 0.246 million € (when w = 0.9). Comparably, the total cost of day 1 in Case I is 0.246 million €. This is approximately 500 € less than the highest obtained cost in Case III, when almost all weight is put on the objective of the TSO. In Case II, the total cost of the first day is 0.229 million €, which is slightly lower than any solution obtained in Case III.

The costs (not including power procurement costs) are generally lower when the DSOs are weighted the highest, i.e. $w \leq 0.5$. That is because the cost of power procurement is carefully considered. When the TSO is weighted the highest, i.e. $w > 0.5$, the cost of power procurement in the distribution systems is not considered extensively. However, the TSO is a more significant player in terms of power supply. Accordingly, the TSO should be weighted the highest. However, the lowest possible total costs in the system are obtained when the DSOs are weighted higher than the TSO. That is, because the objective value of the distribution systems is generally higher than it is for the TSO, including power procurement.

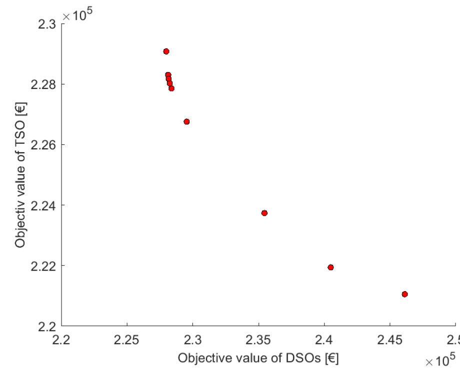

Fig. 4: A subset of the Pareto front of the WSM illustrating the sensitivity on weighting coefficients and the total costs (objective) of the TSO and DSOs.

V. Concluding remarks

Case I and II illustrated the potential of TSO-DSO coordination. By comparing the two cases, the value of coordination becomes evident. An in-depth analysis shows the validity of the coordinated model in Case II. The results show a meaningful cost decrease, though low in percentage of total cost, with the coordinated model. That is, even though the share of DERs in the power system is below 1%.

Case III assessed the impact of including costs between the two levels in the coordinated power system, where the conflicting interests of the TSO and DSOs are considered through multi-objective optimization. This 'game theoretical' case increases the total costs of the power system, where the DSOs now have the largest share. Furthermore, the cost of

This is the accepted version of an article published in 2019 16th International Conference on the European Energy Market - EEM 2019
http://dx.doi.org/10.1109/EEM.2019.8916377

power procurement is approximately 50% of the total system costs. Since the TSO is the most important player in relation to power supply, its objective should be weighted the highest. This results in higher total costs than in the case of assigning a higher weight to the objective of the DSOs.

Acknowledgments: We acknowledge the Centre for Intelligent Electricity Distribution (FME CINELDI) hosted by SINTEF. The centre is funded by the Research Council of Norway through the scheme of the Centres for Environment-friendly Energy Research (FME) and centre partners.

REFERENCES

[1] N. Damsgaard, G. Papaefthymiou, K. Grave, J. Helbrink, V. Giordano, and P. Gentili, "Study on the effective integration of Distributed Energy Resources for providing flexibility to the electricity system. Final report to The European Commission," Tech. Rep., June 2015.

[2] P. Crespo del Granado, R. H. van Nieuwkoop, E. G. Kardakos, and C. Schaffner, "Modelling the energy transition: A nexus of energy system and economic models," *Energy Strategy Reviews*, vol. 20, pp. 229–235, Apr. 2018.

[3] S. Backe, P. Crespo del Granado, A. Tomasgard, D. Pinel, M. Korpast, and K. B. Lindberg, "Towards zero emission neighbourhoods: Implications for the power system," in *2018 15th International Conference on the European Energy Market (EEM)*, June 2018, pp. 1–6.

[4] J. Tran, R. Madlener, and A. Fuchs, "Economic optimization of electricity supply security in light of the interplay between TSO and DSO," *FCN Working Paper No. 21/2016*, pp. 1–35, Dec. 2016.

[5] Z. Yuan and M. R. Hesamzadeh, "Hierarchical coordination of tso-dso economic dispatch considering large-scale integration of distributed energy resources," *Applied Energy*, vol. 195, pp. 600–615, June 2017.

[6] W. A. Bukhsh, C. Zhang, and P. Pinson, "An integrated multiperiod opf model with demand response and renewable generation uncertainty," *IEEE Transactions on Smart Grid*, vol. 7, pp. 1495–1503, Dec. 2015.

[7] E. Mahboubi Moghaddam, M. Nayeripour, J. Aghaei, A. Khodaei, and E. Waffenschmidt, "Interactive robust model for energy service providers integrating demand response programs in wholesale markets," *IEEE Transactions on Smart Grid*, vol. 3053, pp. 2681–2690, Oct. 2016.

[8] A. Nikoobakht, J. Aghaei, M. Shafie-khah, and J. P.S. Catalo, "Interval based robust chance constrained allocation of demand response programs in wind integrated power systems," *IET Renewable Power Generation*, vol. 13, pp. 930–939, Apr. 2019.

[9] P. Crespo Del Granado, Z. Pang, and S. W. Wallace, "Synergy of smart grids and hybrid distributed generation on the value of energy storage," *Applied Energy*, vol. 170, pp. 476–488, May 2016.

[10] J. Löfberg, "YALMIP: a toolbox for modeling and optimization in MATLAB," *2004 IEEE International Conference on Robotics and Automation (IEEE Cat. No.04CH37508)*, pp. 284–289.

This is the accepted version of an article published in 2019 16th International Conference on the European Energy Market - EEM 2019
http://dx.doi.org/10.1109/EEM.2019.8916377