Influencing the Bulk Power System Reserve by Dispatching Power Distribution Networks using Local Energy Storage

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Abstract

Multiple research works and power systems operational practices have qualitatively associated the progressive connection of stochastic renewable energy resources with the increase of power systems reserve requirements. At the same time, the price and technology of MW-class Battery Energy Storage Systems (BESSs) have considerably improved, which opens up the possibility to make electric distribution networks dispatchable. In this paper, we investigate the impact on the bulk power system of dispatchable electric distribution networks that host a large share of stochastic resources. The essential questions inspiring this research are: (1) Assuming that BESSs are deployed to achieve dispatchability of distribution grids embedding stochastic resources, what is the impact on the bulk power system reserve requirement? (2) Is this large-scale integration of BESSs economically viable compared to centralized reserve procurement from traditional power plants? To address these questions, we consider the case of the Danish transmission grid and the associated fleet of conventional power plants and compare it against locally dispatched distribution grids. We perform stochastic simulations to quantify and validate the amount of reserve necessary to operate this power systems with a desired reliability level. We establish a numerical equivalence between saved conventional reserve capacity and amount of BESS storage deployed in distribution networks. Then, we quantify the economic pay-back times

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of BESSs capital expenditure (CAPEX). The results show that: 1) large scale deployment of BESSs with dispatchable distribution networks is a viable technical solution to address flexibility requirements for the bulk power system and 2) this solution is economically viable with a pay-back time in the range of 11-14 years compared to providing flexibilities from conventional power plants.

Keywords:
Reserve Capacity, Regulating Power, Energy Storage Systems, Distribution Networks, Power System Reliability

1. Introduction

Increased reserve and steeper ramping requirements for conventional generation are among the most pressing technical concerns related to increasing the proportion of electricity production from renewable energy sources in the generation mix.

The conventional approach to counteract these issues refers to the deployment/use of fast generating units, like gas-fired and hydro power plants, see for example [1]. As an alternative to the centralized procurement of regulating power, solutions based on exploiting local flexibility have been considered in the literature, such as demand-side management and distributed storage, like battery energy storage systems (BESSs) and power-to-gas. Especially, the use of grid-connected BESSs, traditionally considered for microgrids [2, 3], is gaining interest even in the context of interconnected power systems thanks to their decreasing cost, level of technical maturity, reliability [4] and fast ramping rate, an important element if considering the reduced level of spinning mass and system inertia in future grids.

Most of the applications for BESS proposed in the literature are tailored to accomplish local distribution network objectives, e.g. peak shaving [5], congestion management [6], self-consumption [7], energy arbitrage [8], and trading in the ancillary services market [9, 10, 11]. The use of storage has been also proposed to dispatch the operation of traditionally stochastic generation, e.g. wind and PV farms [12, 13, 14, 15, 16]. In general, this approach consists in compensating the deviations from a dispatch plan (i.e. computed before the operation by leveraging forecasts and a model of the uncertainties) by controlling the BESS's power injection. In [17], this idea was enlarged and demonstrated for a set of heterogeneous resources in a medium voltage (MV) network, including both demand and distributed renewable generation. In the following, we refer to this paradigm as *dispatched-by-design distribution systems*. The principle underlying this paradigm is that dispatching traditionally stochastic power flows inherently reduces the system reserve requirements needed to operate the grid reliably. Compared to designs based on explicit re-dispatch of generation, which might require intensive communication procedures, it is less complex because the coordination mechanism is implicit and given by the commitment of operators to track pre-established dispatch plans, which can be communicated at a slower pace.

The available literature mostly focus on the definition of the algorithms for controlling storage with, however, no emphasis nor quantitative analysis on how coordinated operations of distributed storage can contribute to improving performance at the system level. Motivated by the objective of understanding the advantages of large-scale integration of storage, we consider in this work *dispatched-by-design distribution systems* as the operational paradigm implemented by distributed BESSs. From this standpoint, we investigate the effect of varying the penetration level of *dispatched-by-design distribution systems* in the bulk grid on the amount of reserve required to operate the global electrical grid with a predefined level of reliability. Also, based on an existing model for the price of regulating power, we perform an economic assessment to quantify the economic pay-back times of BESSs capital expenditure (CAPEX). The essential questions inspiring this research are: assuming that BESSs are deployed to achieve dispatch-by-design operation of distribution systems, what is the impact on total power system reserve requirements? Is this integration approach economically viable compared to the centralized procurement of reserve from traditional sources?

To address these questions, we consider as a case study the Danish transmission grid and the associated fleet of conventional power plants. We perform stochastic simulations to quantify the reserve requirements necessary to operate the power systems with the desired reliability level (measured by the Expected Load Not Supplied, ELNS, and chosen according to ENTSO-E recommendations). More specifically, we study the following two cases:

- Case I the power reserve is fully provided by conventional power plants;
- Case II the capacity of conventional power plants to provide reserve power is reduced and compensated for by implementing *dispatched-by-*

design distribution systems[1].

Once the amount of regulating power and required storage capacity are obtained for each case, we first quantify the amount of regulating power that can be saved by a given installed storage capacity. Then we perform an economical comparison of power reserve versus storage. The former evaluated by using a cost model adapted from the existing literature, while the latter is quantified by referring to recent assessments of electrochemical storage costs.

The rest of the paper is organized as follows. Section 2 presents the case study and related data set. Simulation methods are described in Section 3. Afterwards, the numerical results regarding reliability assessment as well as economic evaluation of the above mentioned cases are presented in section 4. Section 5 discusses the strengths and uncertainties of the findings in the context of the existing knowledge. Finally, conclusions are presented in section 6.

2. Case Study and Data Set

2.1. West Denmark Power System

The transmission network in Denmark is divided into two separate systems, Western and Eastern respectively synchronized with the European continental grid and Nordic grid. In this work, we consider the Western Danish power system as the case study because of its large wind generation (as stochastic generation source) installed capacity and availability of public power system and power market data. The Western Danish grid includes 126 buses at 400 kV and 165 kV which are connected through 147 transmission lines and 41 high voltage (HV) transformers. It is connected to Sweden, Norway and East Denmark (DC connections with total capacity of 2480 MW) and Germany (AC connections with total capacity of 1780 MW). In general, the internal electricity consumption and production in West Denmark is balanced. In this work, the case study does not consider the above mentioned interconnections for the sake of simplicity. Therefore, hereinafter we refer to the case study as lsolated West Denmark (IWD) power system. Fig. 1 shows the high voltage transmission grid configuration in the IWD power system. In particular, we consider the following 4 kinds of buses:

[1]BESSs are deployed in the distribution grid to dispatch the operation of traditionally stochastic prosumption power flows. This analysis is carried out considering different penetration levels of *dispatched-by-design distribution systems*, which corresponds to as many different values of deployed storage capacity.

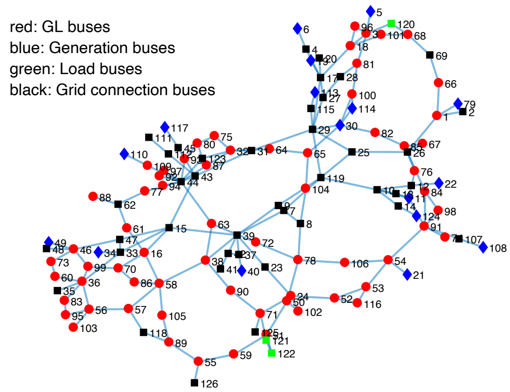


Figure 1: High voltage (HV) grid topology in West Denmark

- generation bus: only generation units are connected to the bus;
- load bus: only aggregated downstream loads (power consumers) are connected to the bus;
- generation + load (GL) bus: both the generation units and downstream loads are connected to the bus;
- grid connection bus: neither generation units nor downstream loads are connected to the bus.

The information about the grid topology, the technical parameters of the transmission lines (i.e., type, impedances, power flow capacity, length and nominal voltage of each line), and high voltage transformer data, are from [18]. Moreover, the unavailability and failure rates of the main components like transmission lines and transformers are obtained from the European Network of Transmission System Operators for Electricity (ENTSO-E) report on Nordic grid disturbance statistics in 2014 [19].

Two-hundred-twenty-seven power generation units are connected to the grid through the GL and generation buses, for an overall generation capacity of 7321.3 MW.The detailed technical data of generators including nominal apparent power, minimum and maximum active power output, and location (bus number) of each generator are available in [18] and used in this study to fully replicate the system. The unavailability and the failure rates of the generators are determined as a function of the type of each unit according to the statistical data available in [20]. The total load (electric energy consumption), during one hour, distributed among GL and load buses of the

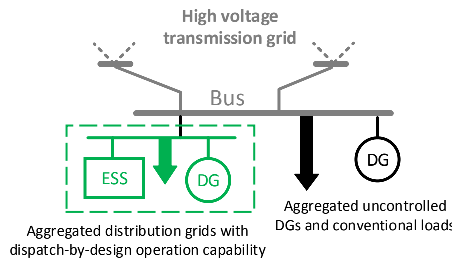


Figure 2: Composition of an HV bus: a *dispatched-by-design distribution system* (left) and a conventional distribution system (right) are connected to the bus.

system is 2071.9 MWh (in other words, total power demand of the system is 2071.9 MW).

2.2. Distribution Networks with Dispatch-by-Design Capability

Whereas conventional power plants and large-scale renewable energy facilities are connected to GL and generation buses, downstream distribution grids are interfaced to the high voltage transmission grid through GL and load buses. These buses include aggregated loads and stochastic Distributed Generations (DGs). In Case II, it is assumed that distribution grids with dispatch-by-design capability are aggregated and connected to the GL and load buses. Fig. 2 shows the configuration of an HV transmission bus where the distributed generation and loads are divided into two parts. The first part represents the behavior of aggregated dispatched-by-design distribution systems, where the imbalances between the realized power flow and dispatch plan are locally compensated by using BESSs. We assumed that this compensation task is performed in a dispatch-by-design operation scheme as described in [17]. The second part represents aggregated conventional distribution systems, where power imbalances are compensated for by importing reserve from the external HV grid.

It is worth noting that the control of distribution networks with dispatch-by-design capability is not perfect. It might be subject to dispatch-following errors due to innacuracies of the tracking control algorithms or failures of any component in the system. In this study, the dispatch-following error of distribution networks with dispatch-by-design capability is according to actual statistics from the experimental configuration described in [17]. Fig. 3 shows the empirical probability distribution function of the dispatch-following error. It is obtained by considering 16 days of operation, from February 6, 2017 to February 12, 2017 and from May 1, 2016 to May 9, 2016, at 5 minute resolution using the experimental setup illustrated in [17].

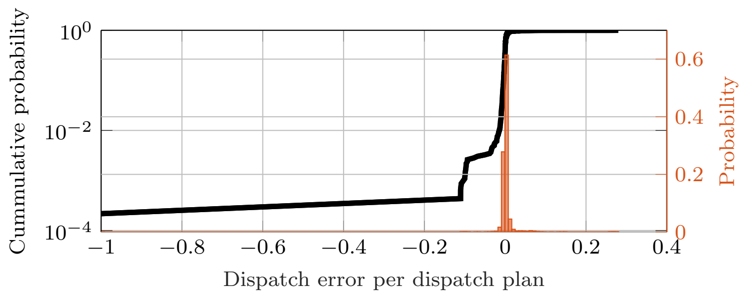


Figure 3: Dispatch error in a realistic distribution network with dispatch-by-design capability[2]

3. Methods

We throughly study the two cases below from both economic and technical perspectives.

- Case I the power reserve is fully provided by conventional power plants;
- Case II the capacity of conventional power plants to provide reserve power is reduced and compensated for by implementing *dispatched-by-design distribution systems.*

In order to analyze these two cases, we developed three main methods. First, we developed a *power system reliability assessment method* to quantify the reliability index (e.g., ELNS) as a function of uncertain parametrs (e.g., deviation of net power injection at each bus from its forecast), and reserve capacity and regulating power provison from conventional power plants.

Second, we applied *Sequential Monte Carlo Simulation* to quantify the energy capacity of ESSs required for covering power mismatches in a distribution network with *Dispatch-by-design* capability.

Third, we developed an *econometric model* to estimate the cost of regulating power from market historical data of Denmark.

3.1. Power System Reliability Assessment Method

This section describes a statistical method which aims to numerically evaluate the risks associated with the operation of power system under uncertainties. Statistical methods based on Monte Carlo Simulation are proposed in the literature to study the risk of blackout in power systems [21, 22]

[2]EPFL dispatchable feeder project, data available in: `http://nanotera-stg2.epfl.ch/`

and the impact of reserve capacity provision from conventional power plants [23]. Here in this study, our power system reliability assessment method is composed by three main parts, namely, scenario generation, system response simulation, and reliability index computation. In comparison with the above mentioned references, the method here is enriched by considering a) the uncertainties coming from uncontrollable stochastic distributed generations as continuous uncertain parameters and b) the uncertainties associated to the dispatch error in power injections from distribution networks with dispatch-by-design capability (e.g., see Fig. 3).

3.1.1. Scenario Generation

Monte Carlo Simulation (MCS) is applied to provide scenarios that represent uncertain parameters of the system. Two types of uncertain parameters, namely, binary and continuous parameters are considered in this section.

First, the availability states of generation (i.e., centralized conventional power plants) and transmission (i.e., overhead lines, cables, and transformers) components is modeled based on two-states 0 (unavailable), 1 (available) Markov chain model. Dagger sampling technique is used. For each component i with unavailability probability p_i, a single 0 state is randomly selected within each $\lfloor 1/p_i \rfloor$ trials. The unavailability probability p_i is computed as (1).

$$p_i = \frac{MTTR_i}{MTTR_i + 1/\lambda_i} \tag{1}$$

where $MTTR_i$ is the so-called Mean Time To Repair and λ_i is failure rate of component i. For scenario (trial) s, the generated power from conventional power plant g is as (2).

$$G_g^s = G_g^0.A_g^s \quad \forall g \in \mathcal{G} \tag{2}$$

where G_g^0 is the scheduled output power and A_g^s is its availability state for scenario s. $\mathcal{G}$ is set of all generators (conventional power plants).

Second, the deviation of net power injection at each load bus and GL bus ($b \in \mathcal{B}$) of the system from its forecast (scheduled) value is considered as a continuous uncertain parameter. The net power injection at bus b (i.e., N_b) is composed by three components, namely, uncontrollable loads, uncontrollable distributed generations and controllable distribution networks under

"Dispatch-by-design" scheme. For each scenario (trial) s, the net power injection at bus b is computed using set of equations (3).

$$N_b^s = DG_b^s - L_b^s + DF_b^s \quad \forall b \in \mathcal{B} \tag{3a}$$

$$DG_b^s = DG_b^0 + \Delta DG_b^s \quad \forall b \in \mathcal{B} \tag{3b}$$

$$L_b^s = L_b^0 + \Delta L_b^s \quad \forall b \in \mathcal{B} \tag{3c}$$

$$DF_b^s = DF_b^0 + \Delta DF_b^s \quad \forall b \in \mathcal{B} \tag{3d}$$

DG_b^0 and L_b^0 are the forecasted output power of the aggregated uncontrollable DGs and aggregated uncontrollable loads connected at bus b, respectively. For scenario s, ΔDG_b^s and ΔL_b^s are DG and load forecast errors and are sampled from normal distributions.

DF_b^s is the aggregated power injection schedule (dispatch plan) of *Dispatched-by-design distribution networks* connected at bus b. For scenario s, ΔDF_b^s is the aggregated dispatch plan error which is sampled from an empirical probability distribution function. This function assumed to be known and, in our simulations, is derived from experimental data as presented in section 2.2 (see Fig. 3).

3.1.2. System Response Simulation

For each scenario s, the transmission component availabilities and the system model coupled with nodal net power injections and conventional power plant outputs (i.e., N_b^s and G_i^s) allow to infer the system states and model the initial event. In the simulation procedure, after the initial event or after each step of cascading outages of transmission lines, there may be a power imbalance and, consequently, a frequency deviation in the system. It is assumed that the frequency deviation spreads uniformly in the system and all the generators ($g \in \mathcal{G}$) respond to this power imbalance according to their droop frequency characteristics with repect to their capacity limits (see Figure 4) as formulated in (4).

$$\Delta f^s = \frac{\Delta P^s}{\sum_{g\in\mathcal{G}} \frac{1}{R_g}} \tag{4}$$

where ΔP^s is the initial imbalance power ($\Delta P^s = \sum_{g\in\mathcal{G}} G_g^s - \sum_{b\in\mathcal{B}} N_b^s$) and R_g is the frequency characteristic droop of generator g.

The automatic reserve is numerically deployed in a load flow computation in which a multiple slack model for all the power plants participating to the automatic reserve, is considered. It is noteworthy that, when the frequency deviation in the system (or in each island of the system after cascading outages and system separation) exceeds or subceeds 5% of the nominal frequency (± 2.5 Hz in 50 Hz), all the generators trip and the system is assumed to collapse irrespectively of the automatic load shedding schemes (indeed, these schemes are operative for frequency deviations within ± 2.5 Hz).

Whenever the frequency deviation is in the allowed range (i.e., between 47.5 Hz and 52.5 Hz), but the available capacities of the synchronized generating units are unable to satisfy the load, a frequency load shedding scheme uniformly disconnects the amount of the load to reach a new power balance. After the generation and load balance is restored, a linearized load flow (DCLF) is applied to calculate the power flow and the transmission line loading.

The outage of one line could make the neighboring lines overloaded and cause cascaded outages. It is assumed that each transmission line has a different flow-dependent probability of incorrect trip (this characteristic is modeled as an increasing function of the line flow which is seen by the line protective relay). After each step of cascading outage, power generation and load balance would be restored mainly through the generators automatic response. These generating units reach their new operating points typically in tens of seconds. The model of TSOs response to contingencies (component outages) is considered as a linearized Optimal Power Flow (DC OPF). The aim of the DC OPF is the minimization of the lost load through redispatching the generating units and shedding some loads. This DC OPF is performed once after the third step of cascading outages. The DC OPF is accomplished using simplex algorithm of Linear Programming (LP). In each step of transmission lines outage, if the system is divided into multiple islands, the simulation would be separately performed for each island. It is assumed that each island continues its operation under this condition considering its own constraints.

Figure 4 shows the flowchart system response simulation process for a given scenario s.

3.1.3. Reliability Index Computation

After simulating each scenario, the obtained amount of lost loads is utilized to evaluate the reliability of the system. In this respect, at the end of the MCS trials, the Expected Load Not Supplied (ELNS) is estimated as

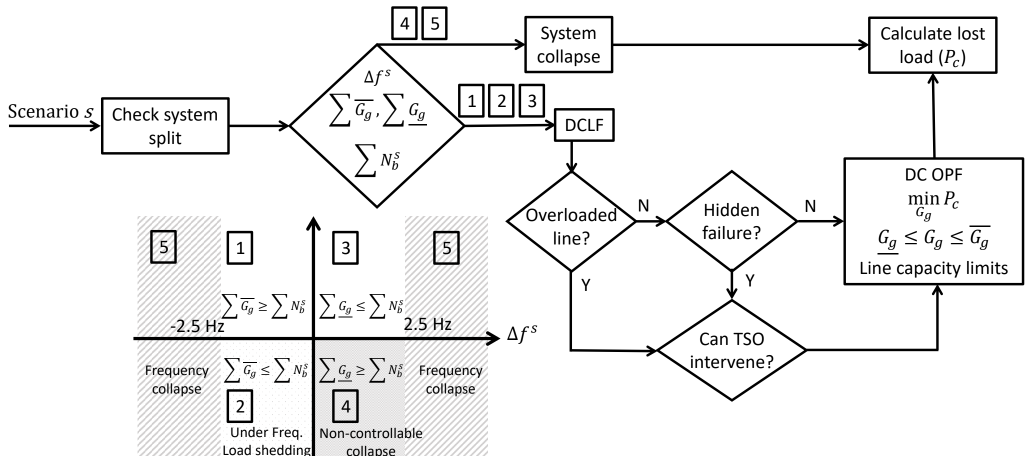


Figure 4: Flowchart and models of the system response simulation for a given scenario s.

follows:

$$\text{ELNS} = \frac{1}{s} \sum_{s} P_c^{(s)} \tag{5}$$

where $P_c^{(s)}$ is the lost load in s-th trial of the MCS. A confidence interval is derived from the sample variance of this estimator, which we take equal to $\text{Var}[\text{ELNS}] = \frac{1}{s-1} \sum_s \left(P_c^{(s)} - \text{ELNS} \right)^2$, and the coefficient of variation, defined by

$$c_v = \frac{\sqrt{\text{Var}[\text{ELNS}]}}{\text{ELNS}} \tag{6}$$

When the MCS is employed to estimate an expected or a mean value, c_v can be used as the stopping criteria to determine a sufficient value of the number of Monte Carlo replicates [21]. In this study the stopping criteria is $c_v = 0.05$, which corresponds to 10% relative accuracy with 95% confidence.

3.2. Storage Capacity Estimation

Sequential Monte Carlo Simulation is applied to find the capacity of required Energy Storage System (ESS) in a distribution network with *dispatch-by-design* capability connected at bus b of the system. In this simulation, each scenario represents annual load and DG (i.e., PV farm) profiles with 1-hour time resolution ($L^{t,s}, DG^{t,s} \quad \forall t \in \{1, 2, .., 8760\}$), as formulated in (7).

$$L_b^{t,s} = L_b^{t,0} + \Delta L_b^{t,s} \quad \forall t \in \{1, 2, .., 8760\} \tag{7a}$$

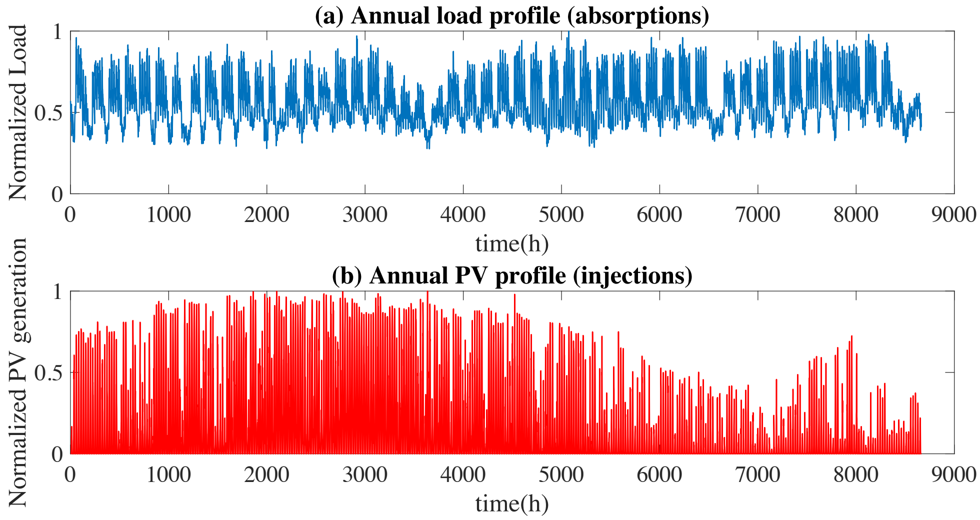


Figure 5: (a) Annual normalized load absoptions (hourly load per peak power demand); (b) Annual normalized PV profile injections (Hourly PV generation per PV power capacity)

$$DG_b^{t,s} = DG_b^{t,0} + \Delta DG_b^{t,s} \quad \forall t \in \{1, 2, .., 8760\} \tag{7b}$$

where $L_b^{t,0}$ and $DG_b^{t,0}$ are typical annual load and DG forecasted profiles as depicted in Figure 5. For each scenario s, $\Delta L_b^{t,s}$ and $\Delta DG_b^{t,s}$ are load and DG forecast errors sampled from normal distributions $\mathcal{N}(0, \sigma_{L_b})$ and $\mathcal{N}(0, \sigma_{DG_b})$, respectively.

In this study, the role of ESS is to cover the net schedule mismatch regarding the deviation of stochastic DGs' production and the consumption of the loads from their forecast. Therefore, at each time step t, the following equation must be satisfied:

$$P_{\mathrm{ESS}_b}^{t} = (DG^{t,0} - DG^{t,s}) - (L^{t,0} - L^{t,s}) \tag{8}$$

where $P_{\mathrm{ESS}_b}^{t,s}$ is the aggregated power charge/discharge of energy storage systems connected at bus b, at time t, for scenario s.

The capacity of ESS in terms of energy (E_{ESS}) is computed such that it covers the above mismatch. It is assumed that the schedule is updated each day, therefore, the time horizon for power mismatch recovering is 24 hours. Hence, the capacity of ESS should be greater than the maximum of the absolute value of the mismatch energy (integral of power mismatch) over

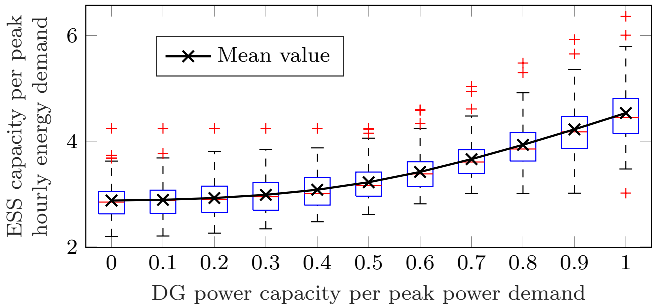


Figure 6: Required storage capacity for *dispatch-by-design* operation capability in a distribution network

24-hours periods during a year as presented in equation (9).

$$E^s_{\text{ESS}_b} = \max_{d\in\{1,\dots,365\}} \max_{t\in\{24(d-1)+1,\dots,24d\}} \left| \sum_{\tau=1}^{t} P^{\tau,s}_{\text{ESS}_b} \right| \tag{9}$$

The total energy capacity of ESSs required for implementation of *dispatched-by-design distribution networks*, in the system is (E^s_{ESS}) is computed as (10)

$$E^s_{\text{ESS}} = \sum_b E^s_{\text{ESS}_b} \tag{10}$$

Fig. 6 shows the total capacity of ESSs where the ratio between peak stochastic DG production and peak load is changing from 0 to 1, for 10,000 forecast error samples. Note that the value of σ_{L_b} is selected proportional to the peak power demand at bus b, such that the standard deviation of total load forecast error (σ_L) is 0.026. Similarly, the value of σ_{DG_b} is selected proportional to DG power capacity at bus b, such that the standard deviation of total DG forecast error (σ_{DG}) is 0.07. These total forecast errors are matched with day-ahead forecast errors observed in West Denmark, in 2015 and 2016. The simulation results show that the average required energy capacity of the ESS for covering the power mismatches is equal to 4.49 p.u., with respect to one year hourly load profile (peak power demand = 1 p.u.) and DG profile (DG power capacity = 1 p.u.).

3.3. Regulating Power Price Model

The model for the cost of regulation is adopted from the existing technical literature [24] (the so-called Skytte model). To the best of the Authors knowledge, it is the most solid attempt to infer the cost of regulating power from market historical data. The analysis was carried out by considering the regulating power market of Oslo region, in Norway, and using data from

December 1996. Back then, the electricity market was already liberalized, even if the participation to the regulating power market was limited to generation units from that specific area only. With respect to the nowadays market structure (e.g., [25]), where imbalances are shared on a much larger geographical scale (provided that enough transmission capacity is available), this factor limited the market competition, not allowing to access potentially cheaper regulating power sources outside that specific bidding area. Nevertheless, since market bidding mechanisms are unchanged, we expect the main findings of Skytte to still apply to nowadays situation. Thus, we select this model to perform an econometric analysis to evaluate if the cost of storage deployment for achieving dispatch-by-design operation of distribution network is economically justifiable compared to the conventional procurement of regulating power. Let π_t^{P} be the market spot-price, S_t the amount of electricity announced in the day-ahead market and D_t the actual delivery, Skytte model states that the price of regulating power per unit of regulating power (π_t^{RP}) is

$$\begin{aligned}\pi_t^{\mathrm{RP}}(\pi_t^{\mathrm{P}}, S_t, D_t) = \varphi \cdot \pi_t^{\mathrm{P}} + 1_{(S_t<D_t)} \cdot [\lambda\pi_t^{\mathrm{P}} + \mu(S_t - D_t) + \eta] \\ +1_{(S_t>D_t)} \cdot [\alpha\pi_t^{\mathrm{P}} + \gamma(S_t - D_t) + \beta]\end{aligned} \tag{11}$$

where 1. is an activation function (one when the argument is true), and $\varphi, \lambda, \mu, \eta, \alpha, \gamma$, and β are model coefficients to determine by fitting the model. The market data of West Denmark in 2015 and 2016, with one hour time resolution, is used to fit the model and eventually find the model coefficients. As a result of the fitting process, the values of the coefficients in the updated model are as follows: $\varphi = 0.712$ €/MWh, $\lambda = 0.212$€/MWh, $\mu = -0.0067$€/MWh, $\eta = 0.197$€, $\alpha = 0.197$ €/MWh, $\gamma = -0.008$€/MWh, and $\beta = 0.635$. The coefficient of determination (R-squared) of the updated model is 0.81 which is in line with the range of latest regulating power price fitting models proposed for different areas of Nordic power market (0.61-0.83) in the literature [26]. Finally, it is worth noting from equation (11) that the total cost of regulation is given by the product between π_t^{RP} and the amount of regulating power ($S_t - D_t$), thus the cost of provision of regulating power is in general quadratic with respect to the regulating power requirement.

4. Results

4.1. Reliability Assessment

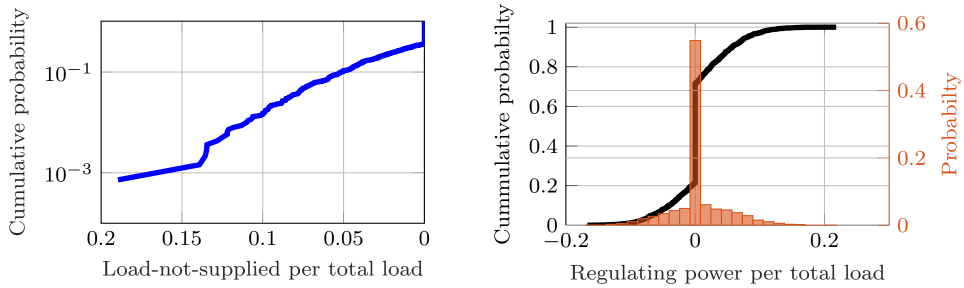
In this section, the power system reliability assessment simulator is used to assess the reliability of the Isolated West Denmark power system in a base case regarding limited reserve capacity. Then, we quantitatively discuss how Case I and Case II improves the reliability of the system.

4.1.1. Base Case

First, we investigate the base case adopted from the Danish transmission system data set [18] in which the stochastic DG penetration is set to 50% (this value corresponds to the wind penetration in terms of energy production in West Denmark in 2016) and all the power is delivered to the end consumers through conventional (i.e., non-dispatchable) distribution grids. The stochastic DGs are distributed in all the 126 buses of the system where the capacity of stochastic DG per bus is randomly obtained from a uniform distribution. Afterwards, the stochastic DG capacities are modified proportional to the power demand of each bus such that the total stochastic DG capacity in the system per total power demand of the system is equal to 50% (i.e., in terms of energy, the total scheduled stochastic DG production is 1035.95 MWh). This scenario is referred to as base case in the following. The deviation of the real-time DG production from its forecasted value at each bus is sampled from a normal distribution such that the standard deviation of the total DG production forecast error is 72.52 MWh (i.e., 7% of the total DG production forecast). This forecast error is calculated based on the day-ahead forecasts and real-time wind power production in West Denmark from 2015 to 2016.

The initial set points of the generation units and loads are obtained from Danish TSO data[18]. The total load of the system, in terms of electric energy consumption during one hour, is 2071.9 MWh. The load forecast error at each bus is sampled from normal distributions, where the standard deviation of the total load forecast error is 53.87 MWh (i.e., 2.6% of the total load of the system).

It is assumed that the total reserve capacity is equal to 10% of the total power demand of the system (i.e., 207.19 MW). The reserve capacity is distributed among the conventional power plants proportionally to their available free capacity. The reserve capacity provided by the conventional power plants is divided into two types, i.e. automatic and manual reserves according to the reserve activation mechanism of the units. Quantitatively, it is assumed that the total amount of the reserve capacity (R) is divided into automatic reserves ($R_A = 0.3R$) and manual reserves ($R_M = 0.7R$). The proportion between the automatic and manual reserve is not arbitrary and has been selected to be in line with West Denmark reserve provision data in



(a) (b)

Figure 7: Base case simulation results

2015 and 2016.

Fig. 7a shows the results of the power system reliability assessment simulator in terms of cumulative probability of Load-Not-Supplied (LNS), for 20000 scenarios. It is assumed the total reserve capacity is equal to 10% of the total power demand of the system (i.e., 207.19 MW). Each scenario represents the realization of the uncertain parameters of the system including DG and load forecast error at each bus, availability of the transmission lines and transformers, and availability of generation units. In this case, the value of ELNS is 39.69 MWh (i.e., 0.014 of the total load, one hour energy consumption, of the system). At each scenario, part of the provided reserve capacity is activated to cover the imbalances caused by DG and load forecast errors as well as generation and transmission component outages. The amount of activated reserve (in terms of energy) in both upward and downward directions, is also known as regulating power. Fig. 7b shows the statistical distribution of regulating power in the base case simulation. The values of Expected Regulating Power (ERP), for upward and downward regulation are, 79.24 MWh and 53.48 MWh, respectively.

To validate the above power system reliability results, the value of ELNS for different levels of reserve capacity are calculated independently based on real measurement at 1 hour resolution of the net surplus/deficit power imbalances data for the Isolated West Denmark power system, obtained from [27].To calculate the value of ELNS, it is assumed that, at each hour, any imbalance larger than the provided reserve leads to a load curtailment equal to the difference between the power imbalance and provided reserve. A comparison between the calculated ELNS based on measured imbalance data, for different level of reserve capacity, with the ELNS obtained from the results of our simulator is presented in Fig. 8. As it can be seen, simulated results agree

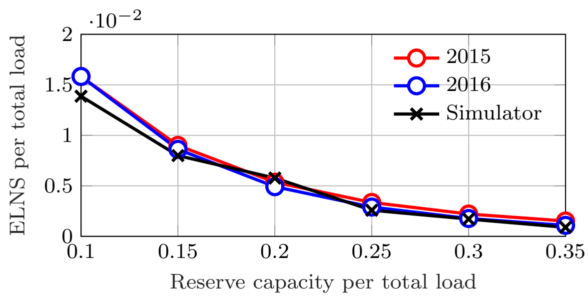


Figure 8: Validation of the results of the proposed simulator

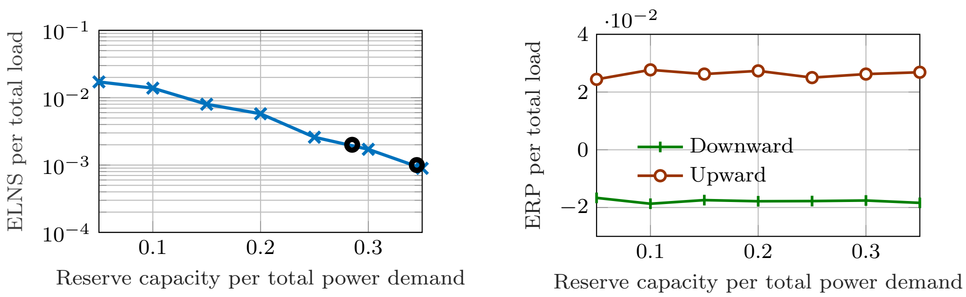
well with the ELNS computed based on empirical distributions of measured power imbalances in 2015 and 2016. This validates the accuracy of the developed simulator and supports the realism of the conclusions obtained with respect to the case of deploying *dispatched-by-design distribution networks*.

In the base case, where the reserve capacity is 10% of the total power demand of the system, the ELNS per total load is 0.014 and far above the ENTSO-E recommendation (0.001-0.002). The main reason for this large risk value is that the generation relies on a considerable proportion of stochastic production, which is uncertain and non-dispatchable. Note that in the considered base case, the interconnections between West Denmark and the neighbouring area (e.g., Germany) are not available to cover power system imbalances. Next, we investigate the proposed cases for enhancing the reliability level of the system.

4.1.2. Case I

In this section, the power system reliability assessment simulator is used to quantify the impact of reserve provision from conventional power plants. Fig. 9a shows how the ELNS reliability index decreases by increasing the amount of reserve capacity provided from conventional power plants. In particular, as denoted by the black marks in Fig. 9a, the TSO requires to provide reserve capacities up to 28.5% and 34.5% of the total power demand of the system in order to satisfy the 0.001 and 0.002 ELNS target values, respectively. These percentages correspond to 373.3 MW and 494.4 MW of extra reserve capacity compared to the base case (10% reserve capacity).

It is worth mentioning that, as showed by Fig. 9b, increasing the amount of reserve capacity provision does not lead to decrease the amount of required regulating power for covering imbalances. The amount of regulating power provides a notion of the aggregated impact of the size of power imbalances in the system. This can be explained by the fact that increasing the amount



(a) (b)

Figure 9: Case I; Simulation results

of reserve capacity does not reduce the size of injected power imbalances, instead it provides a countermeasure to cover those imbalances.

4.1.3. Case II

In Case II, the reserve provision capacity from conventional power plants is 10% of the total power demand of the system. This case is investigated under two schemes. In the first, when a distribution network is enhanced by emerging dispatch-by-design operation capability, it is assumed that all stochastic DG connected to the distribution network is under the dispatch-by-design regime, in other words imbalances are covered locally by exploiting storage flexibility. In the second scheme, only 50% of stochastic DG nominal capacity is under control. Note that the required BESS capacity in a distribution network with the dispatch-by-design capability is a function of the under-controlled stochastic DG capacity as discussed in section 3.2.

Fig. 10 shows how the ELNS reliability index decreases by increasing the penetration of distribution networks with dispatch-by-design capability. As shown in Fig. 10a (i.e., for the case of full DG control), the desired ELNS per total load levels (i.e., 0.001 and 0.002) can be achieved when 44% and 36% of the downstream distribution networks (in terms of capacity) implement dispatch-by-design operation capability for controlling downstream DG and load uncertainties.

As mentioned in section 3.2, an energy storage capacity of 4.49 times the hourly peak load (in MWh) is required to ensure the full DG control scheme.Therefore, 44% and 36% *dispatched-by-design distribution system* penetration levels correspond to the installation of 409 MWh and 3348 MWh BESSs within the distribution networks, respectively.

In the half DG control scheme (see Fig. 10c), the desired ELNS per total load levels (i.e., 0.001 and 0.002) can be achieved when 66% and 55% of

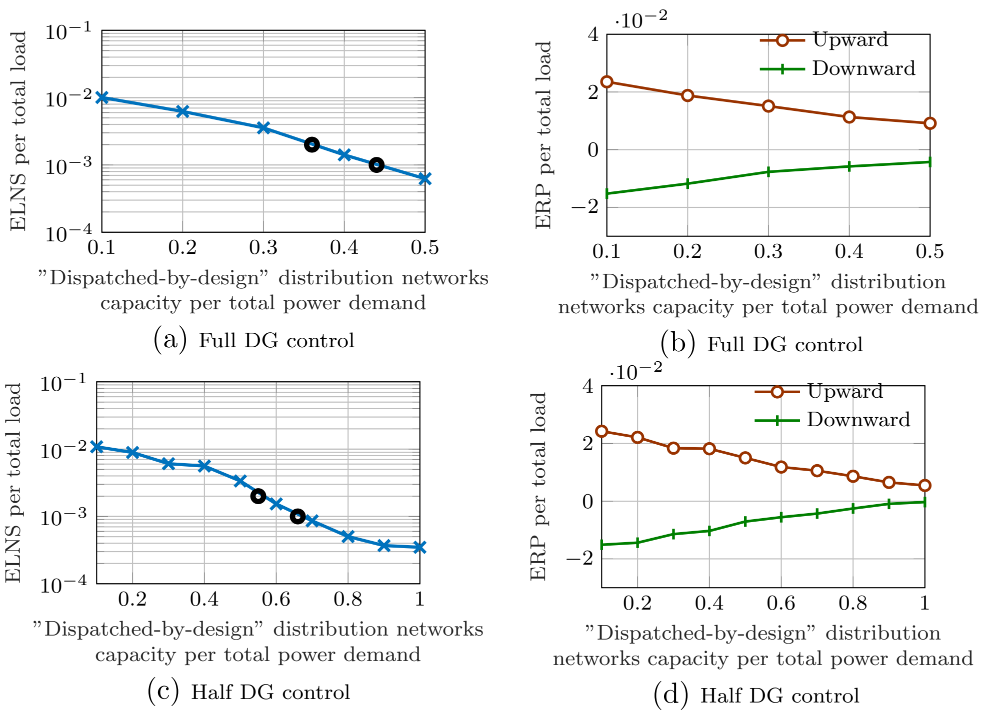


Figure 10: Case II; Simulation results

the downstream distribution networks (in terms of capacity) have dispatch-by-design capability for controlling downstream DG and load uncertainties. In this scheme, energy storage systems with a total capacity of 3.21 times the peak hourly load of the distribution network are required (see Fig. 6). Therefore, 66% and 55% *dispatched-by-design distribution system* penetration levels correspond to the deployment of 4387 MWh and 3656 MWh total BESS capacity in the system, respectively.

It is worth noting that, in Case II, the amount of reserve capacity provided by conventional power plant is constant (10% of total power demand of the system). However, the amount of activated energy from those reserve capacities decreases by increasing the penetration of distribution networks with dispatch-by-design capability. This is thanks to dispatching stochastic flows by properly operating the BESSs.

By comparing the two schemes, we can conclude that the amount of required BESS capacity necessary to achieve the desired reliability level in the system depends on the total stochastic DG capacity which is controlled in the distribution networks with dispatch-by-design capability. This can be achieved either through higher penetration of half control scheme distribution

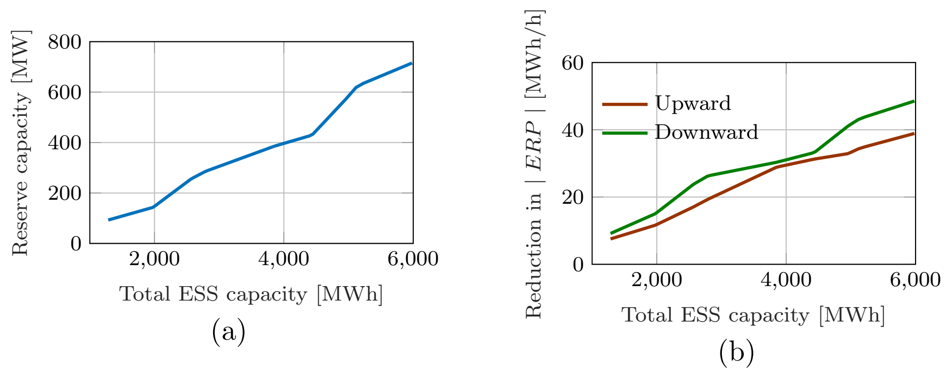


Figure 11: Impacts of energy storage systems on reserve capacity and regulating power requirements

networks or though lower penetration of full DG control scheme distribution networks. Numerical results show that the required BESS capacity in the full DG control scheme is lower than the half DG control scheme. However, this intuitive result finds, thanks to the proposed method in this paper, a quantitative reply. In particular, we can compute the amount of required BESSs capacity to achieve a desired level of ELNS as a function of the controlled stochastic DG capacity.

Finally, we quantify the impact of installed BESS capacity on system reserve requirements. For this purpose, Fig. 11a shows the equivalent reserve capacity provided by conventional power plants that could be replaced by dispatching distribution network as a function of the total capacity of energy storage systems. Moreover, Fig. 11b shows the average hourly reduction in required upward/downward regulating power by installing *dispatched-by-design distribution systems* as a function of the total capacity of energy storage systems.

4.2. Economic Evaluation

In this section, we evaluate the economic costs of implementing Case I and II. In general, the cost of each solution depends on the structure of the power system and local regulations and varies from country to country. Here, we refer to the Nordic power systems structure, where the TSO of each country is responsible for the secure operation of its own system.

In Case I, the TSO buys reserve capacity and regulating power from the market to meet the required reliability level. The total annual operational cost is given by buying reserve capacities and regulating power from the market. It is assumed that generation companies are able to offer required capacities in the market. This annual cost has two components, namely, the cost of buying reserve capacities (manual and automatic reserve capacities)

Table 1: Annual costs associated with the implementation of case I

Year	ELNS per total load	Reserve capacity cost (M€)		Regulating power cost (M€)		Total cost (M€)
		Manual	Auto	Upward	Downward	
2015	0.001	1.51	39.48	13.29	-10.20	44.09
	0.002	1.25	32.62	12.98	-9.74	37.11
2016	0.001	3.03	45.43	15.64	-11.84	52.26
	0.002	2.50	37.52	15.28	-11.31	44.00

and the cost of activating reserve capacities (upward and downward regulating power). The cost of buying reserve capacities are computed based on the average reserve capacity prices in West Denmark in 2015 and 2016.

The annual cost for Case I is shown in Table 1. Note that the amount of demand for the regulating power is obtained from the simulation of Case I depicted in Fig. 9. Afterwards, the annual cost of the upward and downward regulating power is calculated using the developed cost estimation model with respect to the West Denmark spot market hourly prices in 2015 and 2016.

Implementing Case II requires the installation of BESSs to implement the dispatched-by-design scheme for distribution systems. Here, for the sake of a fair comparison, we assume that BESS investment costs are covered by the TSO pays, who will benefit from the reduction in the required reserve and regulating power. The price per kWh of BESSs is adapted from [28]. Apart from the investment cost, the TSO has to buy required reserve capacities (i.e., 10% of total power demand) as well as regulating power from the market. Tables 2 and 3 summarize the annual cost of the TSO for Case II regarding the full and half DG control schemes, respectively.

As we can see in Tables 2 and 3, at each year, the cost of reserve capacity provision (manual and automatic reserves) is constant. However, the higher the penetration of distribution networks with dispatch-by-design capability (which correspond to lower ELNS criteria), the lower the cost of activating these reserves (upward and downward regulating power).

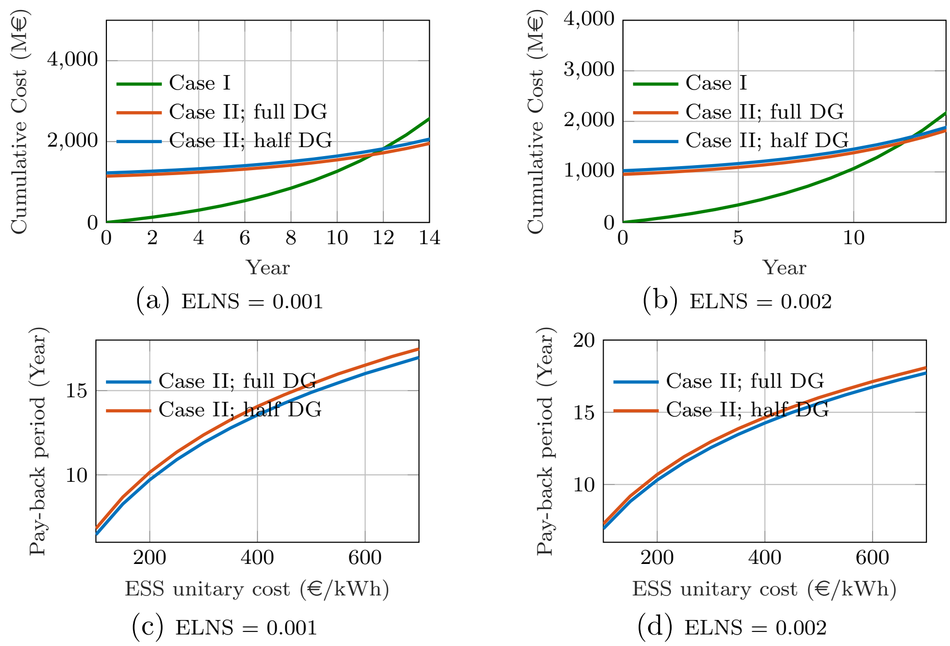
To compare case I and case II from the economic perspective, the yearly

Table 2: Annual costs associated with the implementation of case II; Full DG control

Year	ELNS per total load	Reserve capacity cost (M€)		Regulating power cost (M€)		Total cost (M€)
		Manual	Auto	Upward	Downward	
2015	0.001	0.44	11.44	5.5	-2.94	14.44
	0.002	0.44	11.44	6.72	-3.72	14.89
2016	0.001	0.88	13.17	6.41	-3.42	17.03
	0.002	0.88	13.17	7.85	-4.33	17.65

Table 3: Annual costs associated with the implementation of case II; Half DG control

Year	ELNS per total load	Reserve capacity cost (M€)		Regulating power cost (M€)		Total cost (M€)
		Manual	Auto	Upward	Downward	
2015	0.001	0.44	11.44	5.95	-2.86	14.97
	0.002	0.44	11.44	7.02	-3.57	15.33
2016	0.001	0.88	13.17	6.94	-3.34	17.65
	0.002	0.88	13.17	8.20	-4.16	18.08



(a) ELNS = 0.001 (b) ELNS = 0.002

(c) ELNS = 0.001 (d) ELNS = 0.002

Figure 12: Econmic evaluation regarding different levels of desired reliability index

cumulative cost (CC) is:

$$CC(Y) = IC + \sum_{y=0}^{Y-1} AOC(y), \tag{12}$$

where IC is the investment cost at the beginning year 0, and $AOC(y)$ is the annual operational costs in year y. In other words, the cumulative cost ($CC(y)$), is the investment cost plus sum of all the annual operational costs from the beginning until end of year y.

Figs. 12a and 12b presents the yearly cumulative costs for two desired reliability levels (i.e., ELNS per total load = 0.001 and ELNS per total load = 0.002). Here, the year 0 corresponds to 2016. The annual costs for years after 2016 are calculated based on the projection of the annual costs of 2015 and 2016. The cost of energy storage systems is 280 €/kWh if considering the log fit of market leaders cost estimates in 2015 [28]. We can see in this figure that the cumulative costs associated with Case II (both DG control schemes), is mainly dominated by the initial investment cost. Therefore, in the earlier years, the cumulative cost of Case I is much lower than the cost of Case II. However, the annual operational cost of Case II is much lower. Hence, as we can see in Figs. 12a and 12b, the total cumulative cost of Case

II becomes lower than of Case I after 11 years (when the target ELNS per total load is 0.001) and 12 years (ELNS per total load equal to 0.002). It is noteworthy that, from an economic perspective, 11 and 12 years break-even points are smaller than the lifetime of current battery technologies, which is in the range of 20 years. Finally, a sensitivity analysis is provided to quantify the pay-back time (i.e., break-even points compare to case I) of investment costs associated with Case II, as a function of the unitary cost of BESS capacity. The results, as presented in Figs. 12c and 12d, show that the pay back time of case II (both full and half DG control schemes) is lower than 20 years life time of BESSs for unitary cost of BESS up to 700 €/kWh.

5. Discussion on the Strengths and Uncertainties of the Findings

In this study we assessed the global impact of distributed energy storage on the bulk power grid. In particular, we have quantified the technical and economic benefits of using energy storage to dispatch the operation of traditionally stochastic power flows of electrical distribution systems and reduce the need for grid reserve of the bulk power system. As this research provides quantitative and actionable results on the potential of storage deployment, it is important to analyze the factors which might impact on the proposed results and conclusions.

First, short-term forecast techniques are advancing in the recent years, thanks to the progress in the methods and, especially, increasing availability of information from metering systems deployed in MV and LV systems. The impact of forecast error (for both uncontrollable loads and stochastic DGs) on numerical results must be carefully considered. On one hand, low forecast error decreases the needs for regulating power in case I. On the other hand, in case II, it also decreases energy storage capacity required for implementation of *Dispatched-by-design distribution systems*. Overall, advances in forecasting would play in favor of both approaches.

Second, economic comparison results might change as the price of energy and regulating power will change in coming years. Moreover, in this study, it is assumed that the current regulating power market structure remains during the life time of energy storage systems.

Third, the cost of installing local energy storage system is considered as the main cost of implementing *Dispatched-by-design distribution systems*. Hence, any auxiliary cost such as the cost associated with the required control and communication infrastructure is neglected.

Finally, it worths to mention that in this work, energy storage systems were devoted to dispatch the operation of local distribution systems, therefore technical and economical results should be considered in this context. Compared to traditional planning schemes (e.g. unit commitment, optimal power flow or market-based approach) where dispatch is enforced considering all the power system components in a single problem (i.e., top-down approach), dispatching distribution systems is a bottom-up coordination strategy where local flexibility is essentially devoted to compensate for local mismatches. This achieve low complexity in terms of communication and especially computation, leading to problems of tractable size. In the view of this consideration, indirect capital costs associated to implement the proposed strategy are considered marginal, explaining why they are neglected in this study. Nevertheless, economic costs to achieve standard reliability levels for power system operations (e.g., redundant infrastructures for control and communication), are not considered and might play in favor of Case I, even if, since they are capital costs, they are normally amortized over time if operation costs are lower.

6. Conclusions

In this paper, we investigated the effect of dispatched-by-design power distribution systems on the amount of reserve required to operate the bulk grid with a certain level of reliability. We considered as a case study the Danish transmission grid and the associated fleet of conventional power plants. The two following cases were considered:

- Case I the power reserve capacity is fully provided by conventional power plants;

- Case II reduced capacity of conventional power plants to provide reserve power that is compensated for by implementing *dispatched-by-design distribution networks*.

In this respect, we have first analyzed the Danish power market and power system data to model the stochastic nature of uncertain parameters such as production and consumption forecast errors and generation and transmission component availabilities.

To perform this assessment, we developed a stochastic simulator to quantify the reserve requirements necessary to operate the power systems with a designed reliability level (measured by the expected amount of load not served, ELNS, and chosen according to ENTSO-E recommendations). The accuracy of the developed simulator has been validated by comparing its results with the ELNS computed based on real imbalance measurements in West Denmark in 2015 and 2016.

A Monte Carlo Simulation model is developed and applied to quantify the capacity of required energy storage system in a distribution network with dispatch-by-design operation capability as a function of the capacity of controlled stochastic DG. Once the amount of regulating power and required storage capacity are obtained for each case, we quantified the amount of regulating power that can be saved by a given installed storage capacity. Then we performed an economical comparison of power reserve versus storage. The former evaluated by using a cost model adapted from the existing literature, while the latter is quantified by referring to recent assessments of electrochemical storage costs. The results show that 1) large scale deployment of BESSs under dispatch-by-design architecture of distribution network is a viable technical solution to address flexibility requirements of power systems and 2) this solution is economically viable with a pay-back time in the range of 11-14 years (depends on deployment schemes) compared to providing flexibilities from conventional power plants. Note that the life time of commercialized BESSs is 20 years which is much higher than the pay-back range.

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