Qualification and Quantification of Reserves in Power Systems Under High Wind Generation Penetration Considering Demand Response

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***Abstract*—The presence of high levels of renewable energy resources (RES) and especially wind power production poses technical and economic challenges to system operators, which under this fact have to procure more ancillary services (AS) through various balancing mechanisms, in order to maintain the generation-consumption balance and to guarantee the security of the grid. Traditionally, these critical services had been procured only from the generation side, yet the current perception has begun to recognize the demand side as an important asset that can improve the reliability of a power system, offering notable advantages. In this study, a two-stage stochastic programming model, representing the day-ahead market clearing procedure on an hourly basis and the actual minute-to-minute operation of the power system, is developed comprising different services that specifically address various disturbance sources of the normal operation of a power system, namely intra-hour load variation, intra-hour wind variation, as well as generating unit and transmission line outages.**

***Index Terms*—Ancillary services, contingency reserves, demand response, load-following reserves, stochastic programming.**

NOMENCLATURE

A. Indices and Sets

$f(F)$	Steps of the marginal cost function of unit i.
$i(I)$	Generating units.
$j_1(J_1)$	Load-serving entity 1 (LSE1).
$j_2(J_2)$	Load-serving entity 2 (LSE2).
$r(R)$	Inelastic loads.
$s(S)$	Scenarios.
$t_1(T_1)$	Time intervals of the first stage.
$t_2(T_2, T_2^{\mathrm{in}})$	Time intervals of the second stage.
$w(W)$	Wind farms.

Remark I: To state that an equation holds "for every" element of a set instead of, e.g., $\forall i \in I$, for the sake of brevity, $\forall i$ is used.

Remark II: The notation $t_2 \in T_2^{\mathrm{in}}$ means that t_2 belongs to the hour t_1 that appears in the same equation.

B. Variables

b_{i,f,t_1}	Power output scheduled from the fth block by unit i in period t_1 (MW).
$\mathrm{CA}_{i,t_2,s}$	Additional cost in period t_2, in scenario s, incurred due to change in commitment status of unit i (€).
$f_{l,t_2,s}$	Power flow through line l, in period t_2, in scenario s (MW).
$L_{r,t_2,s}^{\mathrm{shed}}$	Load shed in from inelastic load r, in period t_2, in scenario s (MW).
$\mathrm{LSE1}_{j_1,t_2,s}^{d}$	Total down reserve deployed from LSE1 j_1, in period t_2, in scenario s (MW).
$\mathrm{LSE1}_{j_1,t_2,s}^{d,x}$	Load-following down reserve ($x = \{\mathrm{load}, \mathrm{wind}\}$) deployed from LSE1 j_1, in period t_2 in scenario s (MW).
$\mathrm{LSE1}_{j_1,t_1}^{\mathrm{DN}}$	Total down reserve scheduled from LSE1 j_1, in period t_1 (MW).
$\mathrm{LSE1}_{j_1,t_1}^{\mathrm{DN},x}$	Load-following spinning down reserve ($x = \{\mathrm{load}, \mathrm{wind}\}$) scheduled from LSE1 j_1, in period t_1 (MW).
$\mathrm{LSE1}_{j_1,t_2,s}^{\mathrm{real}}$	Actual consumption of LSE1 j_1, in period t_2, in scenario s (MW).
$\mathrm{LSE1}_{j_1,t_1}^{\mathrm{sch}}$	Scheduled demand from LSE1 j_1, in period t_1 (MW), constrained by $\mathrm{LSE1}_{j_1,t_1}^{\min}$ and $\mathrm{LSE1}_{j_1,t_1}^{\max}$.
$\mathrm{LSE1}_{j_1,t_2,s}^{u}$	Total up reserve deployed from LSE1 j_1, in period t_2, in scenario s (MW).
$\mathrm{LSE1}_{j_1,t_2,s}^{u,x}$	Load-following up reserve ($x = \{\mathrm{load}, \mathrm{wind}\}$) deployed from LSE1 j_1, in period t_2, in scenario s (MW).
$\mathrm{LSE1}_{j_1,t_1}^{\mathrm{UP}}$	Total up reserve scheduled from LSE1 j_1, in period t_1 (MW).
$\mathrm{LSE1}_{j_1,t_1}^{\mathrm{UP},x}$	Load-following spinning up reserve ($x = \{\mathrm{load}, \mathrm{wind}\}$) scheduled from LSE1 j_1, in period t_1 (MW).

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$\text{LSE2}^{d,\text{con}}_{j_2,t_2,s}$ Contingency spinning down reserve deployed from LSE2 j_2, in period t_2, in scenario s (MW).

$\text{LSE2}^{\text{DN,con}}_{j_2,t_1}$ Contingency spinning down reserve scheduled from LSE2 j_2, in period t_1 (MW).

$\text{LSE2}^{\text{real}}_{j_2,t_2,s}$ Actual consumption of LSE1 j_2, in period t_2, in scenario s (MW).

$\text{LSE2}^{\text{sch}}_{j_2,t_1}$ Scheduled demand from LSE2 j_2, in period t_1 (MW), constrained by $\text{LSE2}^{\min}_{j_2,t_1}$ and $\text{LSE2}^{\max}_{j_2,t_1}$.

$\text{LSE2}^{u,\text{con}}_{j_2,t_2,s}$ Contingency spinning up reserve deployed from LSE2 j_2, in period t_2, in scenario s (MW).

$\text{LSE2}^{\text{UP,con}}_{j_2,t_1}$ Contingency spinning up reserve scheduled from LSE2 j_2, in period t_1 (MW).

$P^G_{i,t_2,s}$ Actual power output of unit i, in period t_2, in scenario s (MW).

P^{sch}_{i,t_1} Power output scheduled for unit i in period t_1 (MW).

R^X_{i,t_1} Total reserve scheduled from unit i in period t_1 (MW).
$X = \{$UP-up spinning, DN-down spinning, NS-non-spinning$\}$.

$R^{X,y}_{i,t_1}$ Reserve scheduled from unit i in period t_1 (MW).
$X = \{$UP-up spinning, DN-down spinning, NS-non-spinning$\}$.
$y = \{$con-contingency, load-for load deviations, wind-for wind deviations$\}$.

$r^x_{i,t_2,s}$ Total reserve deployed by unit i, during period t_2 in scenario s (MW).
$x = \{$up-up spinning, dn-down spinning, ns-non-spinning$\}$.

$r^{x,y}_{i,t_2,s}$ Reserve deployed from unit i, during period t_2 in scenario s (MW).
$x = \{$up-up spinning, dn-down spinning, ns-non-spinning$\}$.
$y = \{$con-contingency, load-for load deviations, wind-for wind deviations$\}$.

$rG_{i,t_2,s,f}$ Reserve deployed from the fth block of unit i, in period t_2, in scenario s (MW).

$S_{w,t_2,s}$ Wind spilled from wind farm w, in period t_2, in scenario s (MW).

SDC^1_{i,t_1} Shut-down cost of unit i in period t_1 (€).

SUC^1_{i,t_1} Start-up cost of unit i in period t_1(€).

$\text{SDC}^2_{i,t_2,s}$ Shut-down cost of unit i in period t_2 in scenario s (€).

$\text{SUC}^2_{i,t_2,s}$ Start-up cost of unit i in period t_2 in scenario s (€).

u^1_{i,t_1} Binary variable-1 if unit i is committed during period t_1, else 0.

$u^2_{i,t_2,s}$ Binary variable-1 if unit i is committed during period t_2 in scenario s, else 0.

W^{sch}_{w,t_1} Scheduled wind power in period t_1, by wind farm w (MW).

y^1_{i,t_1} Binary variable-1 if unit i is starting up in period t_1, else 0.

$y^2_{i,t_2,s}$ Binary variable-1 if unit i is starting up during period t_2 in scenario s, else 0.

z^1_{i,t_1} Binary variable-1 if unit i is shutting down in period t_1, else 0.

$z^2_{i,t_2,s}$ Binary variable-1 if unit i is shutting down during period t_2 in scenario s, else 0.

$\upsilon^{\text{dn}}_{j_2,t_2,s}$ Binary variable-1 if LSE2 j_2 is providing down contingency reserve during period t_2 in scenario s, else 0.

$\upsilon^{\text{LSE2}}_{j_2,t_2,s}$ Binary variable-1 if LSE2 j_2 is providing contingency reserve during period t_2 in scenario s, else 0.

$\upsilon^{u}_{j_2,t_2,s}$ Binary variable-1 if LSE2 j_2 is providing up contingency reserve during period t_2 in scenario s, else 0.

$\delta_{n,t_2,s}$ Voltage angle at node n, in period t_2, in scenario s (rad).

$\psi^{\text{LSE2}}_{j_2,t_2,s}$ Binary variable-1 if LSE2 j_2 is called to provide contingency reserve during period t_2 in scenario s, else 0.

$\zeta^{\text{LSE2}}_{j_2,t_2,s}$ Binary variable-1 if LSE2 j_2 stops providing contingency reserve during period t_2 in scenario s, else 0.

C. Parameters

$A_{n,x}$ Node to resource incidence matrix of resource x (inelastic load, LSE1, LSE2, unit or wind farm). Element is 1 if resource x is located at node n.

B_{i,f,t_1} Size of step f of unit i marginal cost function in period t_1 (MW).

$B_{l,n}$ Absolute value of the imaginary part of the admittance of line l (p.u.).

C_{i,f,t_1} Marginal cost of step f of unit i marginal cost function in period t_1 (€/MWh).

D^{sch}_{r,t_1} Scheduled load (first stage) (MW).

D^2_{r,t_2} Real-time load (second stage) (MW).

DT^1_i Minimum down-time of unit i (first stage) (h).

DT^2_i Minimum down-time of unit i (second stage) (min).

$E^{\text{req}}_{j_1}$ Energy requirement of LSE1 j_1 (MWh).

$f^{\max}_l$ Maximum capacity of line l (MW).

LC_{l,t_2} Line contingency parameter-0 if line l is down during period t_2, else 1.

$\text{N}^{\text{call}}_{j_2}$ Maximum number of calls of LSE2 j_2.

$P^{\max}_i$ Maximum power output of unit i (MW).

$P^{\min}_i$ Minimum power output of unit i (MW).

$\text{prob}(s)$ Probability of wind power scenario s.

$\text{RC}^{\text{DN}}_{i,t_1}$ Offer cost of spinning down reserve by unit i, in period t_1 (€/MWh).

$\text{RC}^{\text{DN,LSE1}}_{j_1,t_1}$ Offer cost of spinning down reserve by LSE1 j_1, in period t_1 (€/MWh).

$\text{RC}^{\text{DN,LSE2}}_{j_2,t_1}$ Offer cost of spinning down reserve by LSE2 j_2, in period t_1 (€/MWh).

$\text{RC}^{\text{NS}}_{i,t_1}$ Offer cost of nonspinning reserve by unit i, in period t_1 (€/MWh).

$\text{RC}^{\text{UP}}_{i,t_1}$ Offer cost of spinning up reserve by unit i, in period t_1 (€/MWh).

$\mathrm{RC}_{j_1,t_1}^{\mathrm{UP,LSE1}}$	Offer cost of spinning up reserve by LSE1 j_1, in period t_1 (€/MWh).
$\mathrm{RC}_{j_2,t_1}^{\mathrm{UP,LSE2}}$	Offer cost of spinning up reserve by LSE2 j_2, in period t_1 (€/MWh).
RD_i	Ramp-down rate of unit i (MW/min).
RU_i	Ramp-up rate of unit i (MW/min).
SDC_i	Shut-down cost of unit i (€).
SUC_i	Start-up cost of unit i (€).
UC_{i,t_2}	Unit contingency parameter-0 if unit i is down during period t_2, else 1.
UT_i^1	Minimum up-time of unit i (first stage) (h).
UT_i^2	Minimum up-time of unit i (second stage) (min).
V_{r,t_2}^{LL}	Cost of involuntary load shedding of inelastic load r, in period t_2 (€/MWh).
$V_{w,t_2}^{\mathrm{spill}}$	Cost of wind energy spillage from wind farm w, in period t_2 (€/MWh).
W_w^{cap}	Wind farm w capacity (MW).
$\mathrm{WP}_{w,t2,s}$	Random variable-power output of wind farm w, in period t_2, in scenario s (MW).
$\lambda_{j_1,t_1}^{\mathrm{LSE1}}$	Utility of LSE1 j_1, in period t_1 (€/MWh).
$\lambda_{j_2,t_2}^{\mathrm{LSE2}}$	Cost at which the system operator can call LSE2 j_2 to provide contingency reserves in period t_2 (€).
ΔT	Duration of time interval of the second stage (min).

I. Introduction

A. Motivation and Background

Ambitious plans for the future of the electricity production, such as the European Union (EU) Climate and Energy Package [1], together with the increased need for energy, render evident the increasing trend toward a low-carbon, efficient and sustainable operation of power systems. The increase in wind generation penetration in recent years [2], [3] has its roots in policy makers' directives that promote this technology in order to exploit its environmental benefits [4]. Yet, its highly volatile and unpredictable nature [5] needs to be balanced by maintaining an adequate level of reserves to confront with possible wind ramping events.

Typically, electricity markets are cleared well before the actual production and delivery of energy [6]; thus, the information available at the time of decision-making is imperfect. Apart from the wind, other uncertain events such as real-time load deviations and contingency events, such as transmission line outages and unit failures should be considered in order to secure the consistency of the grid. Therefore, large-scale integration of wind power generation poses further technical and economic challenges to power systems operation. To accommodate the unpredictable events, power systems are operated through several market structures in different time-scales. Balancing authorities should procure the required ancillary services (ASs) through various mechanisms, in order to ensure that power quality, reliability, and security of the system operation are met under normal and emergency conditions [7]. AS definitions and technical specifications vary from country to country, even from region to region (e.g., in United States), according to the specific conditions and needs of the power system, policy structure and maturity, and thus a definite classification is difficult.

Generally, it can be stated that AS refer to reactive (e.g., voltage regulation), active (e.g., frequency regulation, contingency reserves, etc.), and other critical services (e.g., system restoration after a black-out). Traditionally, these services are procured from the generation side, but various studies including [8] state that the demand could also play an important role in the provision of these critical services, especially by introducing the advantages of immediate, statistically reliable response, and also distributed nature.

Thus, relative to the design of AS provision mechanism, resources both on the generation and the demand side should be evaluated in terms of suitability of providing specific services. The operation of the majority of production units is constrained by ramping time, minimum on, and minimum off time limits. On the other hand, most of the loads can respond instantly (e.g., air-conditioning), curtailing their consumption faster than the generation side would increase the power production. Furthermore, it is reported that the reliability related to the response to a signal of a system operator is greater in the case of aggregation of small responsive loads, rather than in the case of fewer number of large generators [8]. Especially, when considering the reliability and balancing mechanisms of a power system under high renewable generation penetration (e.g., wind power production), demand response (DR) has already been proven to be a flexible tool for operators to use [9]. Despite these pros, the implementation of such demand side schemes is not widely spread. Historically, U.S. markets play a pioneering role in this field, by establishing DR programs that allow the provision of critical AS from the demand side [10]. Europe has taken little steps [11], although the provision of these services by DR programs has been recognized as mandatory in order to support greater future integration of renewable energy sources (RES), mainly due to regulatory barriers.

B. Literature Overview

The topic of qualification and quantification of the appropriate AS to handle the challenging aspects of RES penetration, as well as contingencies, has drawn the attention of various researchers and system operators around the world.

A detailed treatment of the AS that exist in different power systems, in seven different countries, can be seen in [12] and [13]. A tangible demonstration of the capability of loads to provide AS as well as a typology of different AS can be found in [14] and [15]. In [16] and [17], a stochastic security-constrained market-clearing problem is formulated, where line and generator outages are considered through a preselected set of random contingencies, determining the reserves by penalizing the expected load not served. In [18], a two-stage stochastic programming model is developed to evaluate the economic impact of reserve provision under high wind power generation penetration. In [19], a two-stage stochastic model is presented, including dispatchable DR providers, used to meet the security constraints of the system. In [20], a day-ahead market structure is presented, where demand side participates in contingency reserve provision by bidding an offer curve that represents the cost of making the loads available for curtailment.

A comprehensive evaluation of DR activities for AS can be seen in [21]. Apart from the commonly met AS types, a new type was recently proposed by Midwest ISO [22] and California ISO [23] as flexible ramping products to increase the robustness of the load following reserves under uncertainty, such as high solar and wind power ramping events.

Providing AS in a market operation first requires solving a unit commitment (UC) problem. Based on a literature survey on the topic of solving UC problems, a great number of techniques can be found applied in different studies. Among them, meta-heuristic approaches including evolutionary algorithms, particle swarm optimization, tabu search, and simulated annealing as well as their hybrids, have been extensively used for the solution of the UC problem [24]–[30]. Artificial intelligence methods such as fuzzy and expert systems and neural networks have also been used [31]–[32]. Priority list methods [33] were among the first methods applied for the solution of the UC problem.

A last branch of techniques utilized for dealing with the UC problem can be given as mathematical programming methods. Among them, Lagrangian relaxation is proposed in [34] for a transient stability-constrained network structure. The mentioned Lagrangian relaxation method and its improved versions are also employed in [35]–[37]. The combination of Lagrangian relaxation with mixed-integer nonlinear programming (MINLP) is also applied in the literature in [38]. Dynamic programming has also been extensively applied for UC solution in the past [39]. Nowadays, mixed-integer linear programming (MILP) is considered as the state of the art for the UC problem solution. It is almost exclusively employed in modern centralized market clearing engines and has the leading portion in the recent related literature [40]–[42]. A detailed discussion on UC problem solution approaches can be found in [43].

C. Overview of the Study and Contribution

In this paper, a two-stage stochastic programming-based joint energy and reserve market-clearing model within MILP framework is proposed in order to evaluate the required level of reserves in order to tackle with the uncertainty introduced by the increased penetration of wind power generation, intra-hour load variations, line failures, and unit outages that are considered known through a parameter.

The first stage of the model represents the day-ahead market and is cleared on an hourly basis. The second stage is cleared on minute basis (e.g., 10 min) and simulates possible instances of the actual operation of the power system. In order to ensure the system's reliability, several reserve services are employed. First, load-following reserves procured from conventional units and load serving entities (LSE) under an appropriate framework deal with the minute-to-minute load and wind deviations. The power unbalance caused by contingencies related to transmission lines and generators is handled through spinning and nonspinning reserves from online and offline generating units as well as from LSE that are committed to alter their consumption in order to provide emergency reserves. The explicit novel contribution of this paper is the consideration of all the aforementioned resources and operating conditions of a power system in a single joint energy and reserve day-ahead clearing model.

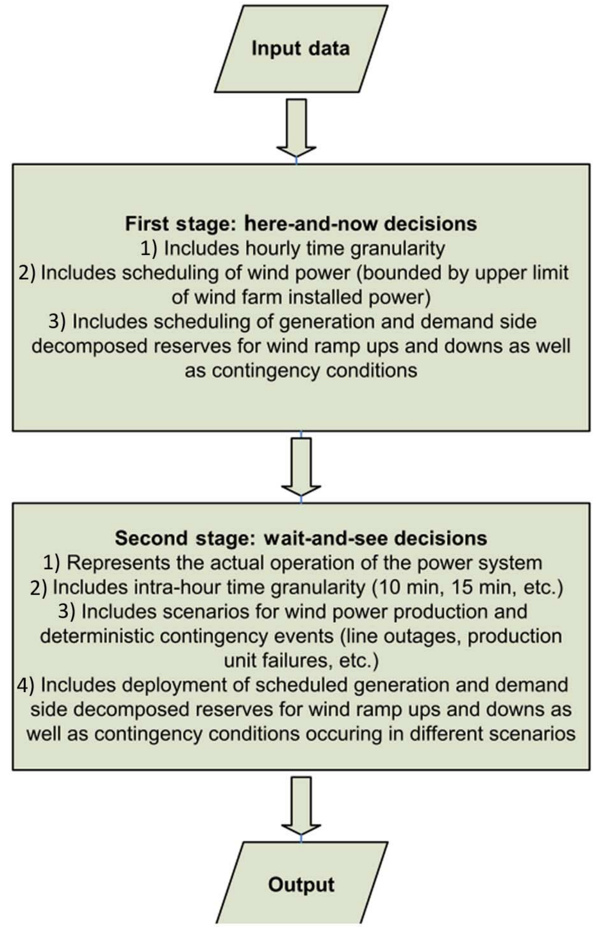

Fig. 1. Flowchart for the proposed methodology.

D. Paper Organization

The remainder of this paper is organized as follows. In Section II, the proposed methodology is presented. In Section III, the obtained results are described and discussed. Finally, conclusions derived from the present study are summarized in Section IV.

II. Methodology

The model consists of two stages as can be seen in Fig. 1, where the first stage represents the day-ahead market and involves variables and constraints that are independent from any specific scenario (here-and-now decisions), while the second stage represents the actual operation of the power system and involves variables and constraints dependent on each scenario (wait-and-see decisions) according to their probabilities of occurrence.

A. Time Granularity

The first stage of the problem is cleared on an hourly basis, while the second stage is cleared on minute basis.

It is common in the literature for the second stage to have the same time granularity as the first one (e.g., [18]). The evaluation of the second stage in such an intra-hour basis provides a more realistic insight into the problem. The time granularity of the second stage can be changed to any preferred time interval.

B. Reserve Types

In the proposed methodology, the following types of reserves are modeled.

1) *Load-following reserves*. This type of reserve is employed by both generators and LSE that are committed to provide this service. It consists of synchronized up and down and also nonspinning reserves that are provided by units to balance the intra-hour load and wind deviations. LSE can also provide up and down reserves of this type to the system on a continuous basis. The consumption of these flexible entities can be scheduled in the day-ahead market operation. In the second stage, it can be rescheduled in order to provide load-following reserves. They contribute to the operating cost through their utility value and a cost to schedule the provision of this service.
2) *Contingency reserves.* In case of a unit or transmission line outage, the deficit of energy is covered by synchronized or nonsynchronized units, or LSE that are committed to provide this service. The LSE that provide this service are considered to be compensated at a cost related with the time they are called to provide this service and are also compensated to be on stand-by.

C. Operation of the Different Types of Loads

In the proposed model, three different types of loads can be identified.

1) *Inelastic load*. The consumption of this type of load cannot be altered. Though under a very high penalty, the system operator may use involuntary shedding of this type of load in order to satisfy the power balance, as a last resort.
2) *LSE* that provide *load-following reserves*. The consumption of this type of load can alter its scheduled consumption within limits in order to respond to wind power fluctuations and intra-hour load deviations.
3) *LSE* that provide *contingency reserves*. The scheduled consumption of this load type can be modified in real time in order to respond to contingencies. Its participation in reserve provision is subject to several constraints. In this paper, it is considered that there are limited times of calls during the horizon and that every call has a specific maximum duration. More detailed behavior (e.g., minimum time between two calls) and contract types can be easily integrated within the proposed methodology.

D. Contingency Incorporation

In this study, it is considered that the transmission line and unit contingencies are perfectly known through a parameter, respectively. When a contingency of a unit occurs, it is assumed that its power output is instantly set to zero. Because of the short length of the horizon under examination, it is assumed that once a unit trips, it stays in failure condition until the end of the study horizon.

When a line failure occurs at some time interval, its power transfer capability is set to zero. It is consider that a line may be repaired within the study horizon.

E. Mathematical Formulation

1) Objective Function:

Eq. (1) shown at the bottom of the page.

$$C'_{i,f,t_2} = \frac{C_{i,f,t_1}}{60} \cdot \Delta T \quad \forall i,\ t_2 \in T_2^{\text{in}}, t_1, f \tag{2}$$

$$\lambda_{j_1,t_2}^{\text{LSE1}'} = \frac{\lambda_{j_1,t_1}^{\text{LSE1}}}{60} \cdot \Delta T \quad \forall j_1, t_2 \in T_2^{\text{in}}, t_1. \tag{3}$$

The objective is to minimize the total expected cost of the system's operation. In (1), the first line describes the start-up and shut-down costs of the units and the cost of energy production. The second line expresses the cost of scheduling reserves from the generation side. The third line considers the utility of the LSE1 load. The next two lines stand for the cost of scheduling reserves from the LSE. The second stage of the formula stands right below and is clearly dependent on the occurrence probability of each scenario. The seventh line considers the additional cost from a start-up/shut-down that was not

$$\begin{aligned}
&\text{Expected cost}\\
&= \sum_{t_1} \Bigg[\sum_i \left(\text{SUC}_{i,t_1}^1 + \text{SDC}_{i,t_1}^1\right) + \sum_i \sum_f \left(C_{i,f,t_1} \cdot b_{i,f,t_1}\right) + \sum_i \left(\text{RC}_{i,t_1}^{\text{UP}} \cdot R_{i,t_1}^{\text{UP}} + \text{RC}_{i,t_1}^{\text{DN}} \cdot R_{i,t_1}^{\text{DN}} + \text{RC}_{i,t_1}^{\text{NS}} \cdot R_{i,t_1}^{\text{NS}}\right)\\
&\qquad - \sum_{j_1} \left(\lambda_{j_1,t_1}^{\text{LSE1}} \cdot \text{LSE1}_{j_1,t_1}^{\text{sch}}\right) + \sum_{j_1} \left(\text{RC}_{j_1,t_1}^{\text{UP,LSE1}} \cdot \text{LSE1}_{j_1,t_1}^{\text{UP}} + \text{RC}_{j_1,t_1}^{\text{DN,LSE1}} \cdot \text{LSE1}_{j_1,t_1}^{\text{DN}}\right)\\
&\qquad + \sum_{j_2} \left(\text{RC}_{j_2,t_1}^{\text{UP,LSE2}} \cdot \text{LSE2}_{j_2,t_1}^{\text{UP,con}} + \text{RC}_{j_2,t_1}^{\text{DN,LSE2}} \cdot \text{LSE2}_{j_2,t_1}^{\text{DN,con}}\right) \Bigg] + \sum_{s}^{j_2} \text{prob}(s)\\
&\quad \cdot \Bigg\{ \sum_{t_2} \Bigg[\sum_i (\text{CA}_{i,t_2,s}) + \sum_i \sum_f \left(C'_{i,f,t_2} \cdot rG_{i,t2,s,f}\right) + \sum_{j_1} \left(\lambda_{j_1,t_2}^{\text{LSE1}'} \cdot \left(\text{LSE1}_{j_1,t_2,s}^u - \text{LSE1}_{j_1,t_2,s}^d\right)\right)\\
&\qquad + \sum_{j_2} \left(\lambda_{j_2,t_2}^{\text{LSE2}'} \cdot \psi_{j_2,t_2,s}^{\text{LSE2}}\right) + \sum_w \left(\frac{V_{w,t_2}^{\text{spill}}}{60} \cdot \Delta\text{T} \cdot S_{w,t_2,s}\right) + \sum_r \left(\frac{V_{r,t_2}^{\text{LL}}}{60} \cdot \Delta\text{T} \cdot L_{r,t_2,s}^{\text{shed}}\right) \Bigg] \Bigg\}
\end{aligned} \tag{1}$$

scheduled and the cost of reserves implemented as energy. The eighth and ninth lines describe the cost of procuring reserve services from LSE. The last line considers the wind spillage and involuntary load shedding during the actual operation of the system.

Equations (2) and (3) adjust the cost of deploying reserves from units and LSE1, respectively. They are needed as the marginal costs; the LSE1 utilities are given in €/MWh, while the actual energy refers to ΔT min intervals.

2) First Stage Constraints:

a) Generation limits:

$$P^{\text{sch}}_{i,t_1} = \sum_f b_{i,f,t_1} \quad \forall i, t_1 \tag{4}$$

$$0 \le b_{i,f,t_1} \le B_{i,f,t_1} \quad \forall i, f, t_1 \tag{5}$$

$$P^{\text{sch}}_{i,t_1} - R^{\text{DN}}_{i,t_1} \ge P^{\min}_i \cdot u^1_{i,t_1} \quad \forall i, t_1 \tag{6}$$

$$P^{\text{sch}}_{i,t_1} + R^{\text{UP}}_{i,t_1} \le P^{\max}_i \cdot u^1_{i,t_1} \quad \forall i, t_1. \tag{7}$$

The generator cost function is considered convex and it is approximated by a step-wise linear function as in [44]. This is enforced by (4) and (5). Constraints (6) and (7) limit the output of a generating unit considering also the scheduled down and up reserves, respectively.

b) Generator minimum up and down time constraints:

$$\sum_{\tau=t_1-\text{UT}^1_i+1}^{t_1} y^1_{i,t_1} \le u^1_{i,t_1} \quad \forall i, t_1 \tag{8}$$

$$\sum_{\tau=t_1-\text{DT}^1_i+1}^{t_1} z^1_{i,t_1} \le 1 - u^1_{i,t_1} \quad \forall i, t_1. \tag{9}$$

Constraint (8) forces a unit to remain committed for at least UT_i periods once it starts up, while (9) forces a unit to remain offline for at least DT_i periods once it is shut-down.

c) UC logic constraints:

$$y^1_{i,t_1} + z^1_{i,t_1} \le 1 \quad \forall i, t_1 \tag{10}$$

$$y^1_{i,t_1} - z^1_{i,t_1} = u^1_{i,t_1} - u^1_{i,(t_1-1)} \quad \forall i, t_1. \tag{11}$$

Equation (10) states that a unit cannot start-up and shut-down during the same period, while (11) enforces the start-up and shut-down status change logic.

d) Start-up/shut-down costs:

$$\text{SUC}^1_{i,t_1} \ge \text{SUC}_i \cdot y^1_{i,t_1} \quad \forall i, t_1 \tag{12}$$

$$\text{SDC}^1_{i,t_1} \ge \text{SDC}_i \cdot z^1_{i,t_1} \quad \forall i, t_1. \tag{13}$$

With (12) and (13), the start-up and shut-down costs of the generators are taken into account.

e) Ramp-up and -down limits:

$$P^{\text{sch}}_{i,t_1} - P^{\text{sch}}_{i,(t_1-1)} \le 60 \cdot \text{RU}_i \quad \forall i, t_1 \tag{14}$$

$$P^{\text{sch}}_{i,(t_1-1)} - P^{\text{sch}}_{i,t_1} \le 60 \cdot \text{RD}_i \quad \forall i, t_1. \tag{15}$$

Constraints (14) and (15) consider the effect of the ramp rates that limit the changes in the unit's output.

f) Generator side reserve limits:

$$0 \le R^{\text{UP}}_{i,t_1} \le 60 \cdot \text{RU}_i \cdot u^1_{i,t_1} \quad \forall i, t_1 \tag{16}$$

$$0 \le R^{\text{DN}}_{i,t_1} \le 60 \cdot \text{RD}_i \cdot u^1_{i,t_1} \quad \forall i, t_1 \tag{17}$$

$$0 \le R^{\text{NS}}_{i,t_1} \le 60 \cdot \text{RU}_i \cdot (1 - u^1_{i,t_1}) \quad \forall i, t_1. \tag{18}$$

Constraints (16)–(18) impose a limit in the scheduling of spinning up and down reserves as well as nonspinning reserve from the generating units.

g) Wind generation limits:

$$0 \le W^{\text{sch}}_{w,t_1} \le W^{\text{cap}}_w \quad \forall w, t_1. \tag{19}$$

Equation (19) imposes a limit on the power accepted by each wind farm.

Unlike the selection made in [18] to consider the upper limit as infinite, here the upper limit is enforced to be equal to the installed capacity of every wind farm.

h) Market equilibrium:

$$\sum_i P^{\text{sch}}_{i,t_1} + \sum_w W^{\text{sch}}_{w,t_1} = \sum_r D^{\text{sch}}_{r,t_1} + \sum_{j_1} \text{LSE1}^{\text{sch}}_{j_1,t_1} + \sum_{j_2} \text{LSE2}^{\text{sch}}_{j_2,t_1} \quad \forall t_1. \tag{20}$$

In the first stage of the model, the network constraints are not enforced. Thus, the power balance is described by the market equilibrium in (20). Undoubtedly, any market representation can be adopted in the first stage.

i) Generator side reserves decomposition in services:

$$R^{\text{UP}}_{i,t_1} = R^{\text{UP,load}}_{i,t_1} + R^{\text{UP,wind}}_{i,t_1} + R^{\text{UP,con}}_{i,t_1} \quad \forall i, t_1 \tag{21}$$

$$R^{\text{DN}}_{i,t_1} = R^{\text{DN,load}}_{i,t_1} + R^{\text{DN,wind}}_{i,t_1} + R^{\text{DN,con}}_{i,t_1} \quad \forall i, t_1 \tag{22}$$

$$R^{\text{NS}}_{i,t_1} = R^{\text{NS,load}}_{i,t_1} + R^{\text{NS,wind}}_{i,t_1} + R^{\text{NS,con}}_{i,t_1} \quad \forall i, t_1. \tag{23}$$

Up-spinning reserves, down-spinning reserves, and nonspinning reserves are scheduled in order to maintain the system balance during the actual operation of the power system that is disturbed due to positive or negative load (elastic or inelastic) deviations, wind ramp-ups and -downs, and contingency events. Up-spinning reserves imply the increase in a synchronized unit's power output, while down-spinning reserves stand for the opposite. Nonspinning reserves are provided by nonsynchronized units as stated by (18). Equations (21)–(23) decompose the unit's total scheduled up, down, or nonspinning reserves to different services that respond to different factors that can trigger the need of such reserves.

j) LSE1 consumption, reserves limits, and decomposition in services:

$$\text{LSE1}^{\min}_{j_1,t_1} \le \text{LSE1}^{\text{sch}}_{j_1,t_1} \le \text{LSE1}^{\max}_{j_1,t_1} \quad \forall j_1, t_1 \tag{24}$$

$$\text{LSE1}^{\text{UP}}_{j_1,t_1} = \text{LSE1}^{\text{UP,load}}_{j_1,t_1} + \text{LSE1}^{\text{UP,wind}}_{j_1,t_1} \quad \forall j_1, t_1 \tag{25}$$

$$0 \le \text{LSE1}^{\text{UP}}_{j_1,t_1} \le \text{LSE1}^{\text{sch}}_{j_1,t_1} - \text{LSE1}^{\min}_{j_1,t_1} \quad \forall j_1, t_1 \tag{26}$$

$$\text{LSE1}^{\text{DN}}_{j_1,t_1} = \text{LSE1}^{\text{DN,load}}_{j_1,t_1} + \text{LSE1}^{\text{DN,wind}}_{j_1,t_1} \quad \forall j_1, t_1 \tag{27}$$

$$0 \leq \text{LSE1}^{\text{DN}}_{j_1,t_1} \leq \text{LSE1}^{\max}_{j_1,t_1} - \text{LSE1}^{\text{sch}}_{j_1,t_1} \quad \forall j_1, t_1 \tag{28}$$

$$\sum_{t_1} \text{LSE1}^{\text{sch}}_{j_1,t_1} = E^{\text{req}}_{j_1} \quad \forall j_1. \tag{29}$$

As stated before, demand side can also contribute in reserves. In this study, we consider two types of LSE that are able to provide reserves. LSE of type 1 can provide up and down load-following reserves as stated by (26) and (28), respectively. This type of reserves is further decomposed into reserves that balance the wind deviations and reserves that balance the intra-hour load deviations, a fact that is enforced by (25) and (27), respectively. Constraint (24) enforces that the scheduled LSE1 demand for each period has to respect the limits of its maximum capability of being altered from a nominal value. To ensure that the LSE1 energy needs are fulfilled during the horizon, despite the fact that it may be scheduled for partial curtailment through the horizon, the energy requirements are enforced by (29).

k) LSE2 consumption and reserve limits:

$$\text{LSE2}^{\min}_{j_2,t_1} \leq \text{LSE2}^{\text{sch}}_{j_2,t_1} \leq \text{LSE2}^{\max}_{j_2,t_1} \quad \forall j_2, t_1 \tag{30}$$

$$0 \leq \text{LSE2}^{\text{UP,con}}_{j_2,t_1} \leq \text{LSE2}^{\text{sch}}_{j_2,t_1} - \text{LSE2}^{\min}_{j_2,t_1} \quad \forall j_2, t_1 \tag{31}$$

$$0 \leq \text{LSE2}^{\text{DN,con}}_{j_2,t_1} \leq \text{LSE2}^{\max}_{j_2,t_1} - \text{LSE2}^{\text{sch}}_{j_2,t_1} \quad \forall j_2, t_1. \tag{32}$$

LSE of type 2 can provide up and down contingency reserves, as stated by (31) and (32), respectively.

Up reserve from the perspective of load has the meaning of consumption reduction, while down reserves stand for a consumption increase. This type of load is not subject to an energy requirement constraint due to the fact that it is paid to be curtailed for prespecified number of periods.

3) Second Stage Constraints:

a) Network constraints:

$$\begin{aligned} A^{\text{wf}}_{n,w} \cdot \sum_{w} (\text{WP}_{w,t_2,s} - S_{w,t_2,s}) + A^{\text{unit}}_{n,i} \cdot \sum_{i} P^{G}_{i,t_2,s} \\ - \sum_{l \in L: n \equiv nn} f_{l,t_2,s} + \sum_{l \in L: n \equiv n} f_{l,t_2,s} \\ = A^{\text{inel}}_{n,r} \cdot \sum_{r} (D^2_{r,t_2} - L^{\text{shed}}_{r,t_2,s}) + A^{\text{LSE1}}_{n,j_1} \cdot \sum_{j_1} \text{LSE1}^{\text{real}}_{j_1,t_2,s} \\ + A^{\text{LSE2}}_{n,j_2} \cdot \sum_{j_2} \text{LSE2}^{\text{real}}_{j_2,t_2,s} \quad \forall n, t_2, s \end{aligned} \tag{33}$$

$$f_{l,t_2,s} = B_{l,n} \cdot (\delta_{n,t_2,s} - \delta_{nn,t_2,s}) \cdot \text{LC}_{l,t_2} \quad \forall (n, nn) \equiv l, n, t_2, s \tag{34}$$

$$-f^{\max}_{l} \cdot \text{LC}_{l,t_2} \leq f_{l,t_2,s} \leq f^{\max}_{l} \cdot \text{LC}_{l,t_2} \quad \forall l, n, t_2, s. \tag{35}$$

In the second stage of the problem, the network constraints are enforced by (33)–(35). If a line outage occurs, the flow through this line is set to zero.

b) Generation limits:

$$P^{G}_{i,t_2,s} \geq P^{\min}_{i} \cdot u^2_{i,t_2,s} \quad \forall i, t_2, s \tag{36}$$

$$P^{G}_{i,t_2,s} \leq P^{\max}_{i} \cdot u^2_{i,t_2,s} \quad \forall i, t_2, s. \tag{37}$$

Through (36) and (37), the minimum and maximum generation limits are also enforced in the second stage of the problem.

c) Ramp-up and -down limits:

$$P^{G}_{i,t_2,s} - P^{G}_{i,(t_2-1),s} \leq \Delta\text{T} \cdot \text{RU}_i \quad \forall i, t_2, s \tag{38}$$

$$P^{G}_{i,(t_2-1),s} - P^{G}_{i,t_2,s} \leq \Delta\text{T} \cdot \text{RD}_i + N_1 \cdot (1 - \text{UC}_{i,t_2}) \quad \forall i, t_2, s. \tag{39}$$

As stated before, a ΔT-minute time interval is adopted in the second stage of the model. As the ramp-up and -down rates of the units are given in MW/min, from interval to interval during the actual operation, the power output of a unit can change by this rate multiplied by ΔT. Constraint (39) is relaxed when the unit i fails.

d) Generator minimum up and down time constraints:

$$\sum_{\tau = t_2 - \frac{\text{UT}^2_i}{\Delta\text{T}} + 1}^{t_2} y^2_{i,t_2,s} \leq u^2_{i,t_2,s} \quad \forall i, t_2, s \tag{40}$$

$$\sum_{\tau = t_2 - \frac{\text{DT}^2_i}{\Delta\text{T}} + 1}^{t_2} z^2_{i,t_2,s} \leq 1 - u^2_{i,t_2,s} \quad \forall i, t_2, s. \tag{41}$$

As the minimum up and down times of a unit are given in minutes for the second stage, they should be divided by the interval length ΔT as indicated by (40) and (41).

e) UC logic constraints:

$$y^2_{i,t_2,s} + z^2_{i,t_2,s} \leq 1 \quad \forall i, t_2, s \tag{42}$$

$$y^2_{i,t_2,s} - z^2_{i,t_2,s} = u^2_{i,t_2,s} - u^2_{i,(t_2-1),s} \quad \forall i, t_2, s. \tag{43}$$

Similar to (10) and (11), constraints (42) and (43) ensure that the logic of UC is preserved.

f) Start-up/shut-down costs:

$$\text{SUC}^2_{i,t_2,s} \geq \text{SUC}_i \cdot y^2_{i,t_2,s} \quad \forall i, t_2, s \tag{44}$$

$$\text{SDC}^2_{i,t_2,s} \geq \text{SDC}_i \cdot z^2_{i,t_2 s} \quad \forall i, t_2, s. \tag{45}$$

In the second stage of the problem, (44) and (45) stand for the start-up and shut-down costs of the generators.

g) Wind spillage and load shedding limits:

$$0 \leq S_{w,t_2,s} \leq \text{WP}_{w,t_2,s} \quad \forall i, t_2, s \tag{46}$$

$$0 \leq L^{\text{shed}}_{r,t_2,s} \leq D^2_{r,t_2} \quad \forall i, t_2, s. \tag{47}$$

Equations (46) and (47) enforce that the system operator, at a high cost, can spill available wind production or shed partially inelastic cost, as a last resort to satisfy the power balance under constrained operation of the power system.

4) Linking Constraints: To simplify the mathematical formulation presented below, we should remark at this point the following: the equations that refer to reserve deployment by generating units hold only for units that are not under contingency. Also, as long as there are no contingencies or wind/load deviations, the reserves provided by the demand side are also zero and the relevant equations do not hold.

a) Additional cost due to the change of commitment status of units:

$$\mathrm{CA}_{i,t_2,s} = \sum_{t_2} \mathrm{SUC}^2_{i,t_2,s} - \mathrm{SUC}^1_{i,t_1} + \sum_{t_2} \mathrm{SDC}^2_{i,t_2,s} - \mathrm{SDC}^1_{i,t_1} \quad \forall i, t_2 \in T_2^{\text{in}}, t_1, s. \tag{48}$$

In case of a difference occurring in the commitment status, a commitment scheduling change cost is charged through (48).

b) Decomposition and deployment of generation side reserves:

$$P^G_{i,t_2,s} = P^{\text{sch}}_{i,t_1} + r^{\text{up}}_{i,t_2,s} + r^{\text{ns}}_{i,t_2,s} - r^{\text{dn}}_{i,t_2,s} \quad \forall i, t_2 \in T_2^{\text{in}}, t_1, s \tag{49}$$

$$r^{\text{up}}_{i,t_2,s} = r^{\text{up,load}}_{i,t_2,s} + r^{\text{up,wind}}_{i,t_2,s} + r^{\text{up,con}}_{i,t_2,s} \quad \forall i, t_2, s \tag{50}$$

$$r^{\text{dn}}_{i,t_2,s} = r^{\text{dn,load}}_{i,t_2,s} + r^{\text{dn,wind}}_{i,t_2,s} + r^{\text{dn,con}}_{i,t_2,s} \quad \forall i, t_2, s \tag{51}$$

$$r^{\text{ns}}_{i,t_2,s} = r^{\text{ns,load}}_{i,t_2,s} + r^{\text{ns,wind}}_{i,t_2,s} + r^{\text{ns,con}}_{i,t_2,s} \quad \forall i, t_2, s \tag{52}$$

$$0 \le r^{\text{up}}_{i,t_2,s} \le R^{\text{UP}}_{i,t_1} \quad \forall i, t_2 \in T_2^{\text{in}}, t_1, s \tag{53}$$

$$0 \le r^{\text{dn}}_{i,t_2,s} \le R^{\text{DN}}_{i,t_1} \quad \forall i, t_2 \in T_2^{\text{in}}, t_1, s \tag{54}$$

$$0 \le r^{\text{ns}}_{i,t_2,s} \le R^{\text{NS}}_{i,t_1} \quad \forall i, t_2 \in T_2^{\text{in}}, t_1, s. \tag{55}$$

Similar to the general (49)–(55) restrictions, the decomposed deployed reserves should be constrained by the corresponding scheduled amount.

c) Decomposition of generation side reserves into blocks:

$$r^{\text{up}}_{i,t_2,s} + r^{\text{ns}}_{i,t_2,s} - r^{\text{dn}}_{i,t_2,s} = \sum_f rG_{i,t2,s,f} \quad \forall i, t_2 \in T_2^{\text{in}}, t_1, s \tag{56}$$

$$rG_{i,t2,s,f} \le B_{i,f} - b_{i,f,t1} \quad \forall i, t_2 \in T_2^{\text{in}}, t_1, s, f \tag{57}$$

$$rG_{i,t2,s,f} \ge -b_{i,f,t1} \quad \forall i, t_2 \in T_2^{\text{in}}, t_1, s, f. \tag{58}$$

With (56)–(58), the reserves are decomposed into the generator power blocks and are materialized as energy.

d) LSE1 reserves deployment and decomposition:

$$\mathrm{LSE1}^{\text{real}}_{j_1,t_2,s} = \mathrm{LSE1}^{\text{sch}}_{j1,t1} - \mathrm{LSE1}^{u}_{j_1,t_2,s} + \mathrm{LSE1}^{d}_{j_1,t_2,s} \quad \forall j_1, t_2 \in T_2^{\text{in}}, t_1, s \tag{59}$$

$$\mathrm{LSE1}^{u}_{j_1,t_2,s} = \mathrm{LSE1}^{u,\text{load}}_{j_1,t_2,s} + \mathrm{LSE1}^{u,\text{wind}}_{j_1,t_2,s} \quad \forall j_1, t_2, s \tag{60}$$

$$\mathrm{LSE1}^{d}_{j_1,t_2,s} = \mathrm{LSE1}^{d,\text{load}}_{j_1,t_2,s} + \mathrm{LSE1}^{d,\text{wind}}_{j_1,t_2,s} \quad \forall j_1, t_2, s \tag{61}$$

$$0 \le \mathrm{LSE1}^{u}_{j_1,t_2,s} \le \mathrm{LSE1}^{\text{UP}}_{j1,t1} \quad \forall j_1, t_2 \in T_2^{\text{in}}, t_1, s \tag{62}$$

$$0 \le \mathrm{LSE1}^{d}_{j_1,t_2,s} \le \mathrm{LSE1}^{\text{DN}}_{j1,t1} \quad \forall j_1, t_2 \in T_2^{\text{in}}, t_1, s \tag{63}$$

$$\sum_{t_2} \frac{\mathrm{LSE1}^{\text{real}}_{j_1,t_2,s}}{\Delta \mathrm{T}} = E^{\text{req}}_{j_1} \quad \forall j_1, s. \tag{64}$$

With (59), the actual consumption of the LSE1 is adjusted, while (60) and (61) decompose the deployed reserves by the LSE1. Similar to (62) and (63) that limit the deployed reserves by their scheduled value, up and down decomposed deployed reserves should also be constrained by their scheduled value. Equality (64) stands for the energy requirement constraint.

e) LSE2 reserves deployment and decomposition:

$$\mathrm{LSE2}^{\text{real}}_{j_2,t_2,s} = \mathrm{LSE2}^{\text{sch}}_{j_2,t_1} - \mathrm{LSE2}^{u,\text{con}}_{j_2,t_2,s} + \mathrm{LSE2}^{d,\text{con}}_{j_2,t_2,s} \quad \forall j_2, t_2 \in T_2^{\text{in}}, t_1, s \tag{65}$$

$$0 \le \mathrm{LSE2}^{u,\text{con}}_{j_2,t_2,s} \le \mathrm{LSE2}^{\text{UP,con}}_{j2,t_1} \quad \forall j_2, t_2 \in T_2^{\text{in}}, t_1, s \tag{66}$$

$$0 \le \mathrm{LSE2}^{d,\text{con}}_{j_2,t_2,s} \le \mathrm{LSE2}^{\text{DN,con}}_{j2,t_1} \quad \forall j_2, t_2 \in T_2^{\text{in}}, t_1, s. \tag{67}$$

Constraints (65)–(67) link the scheduled and the deployed contingency reserves procured by the LSE2. As stated before, no energy requirement constraints are enforced for this type of responsive load.

f) LSE2 reserves provision constraints:

$$\mathrm{LSE2}^{u,\text{con}}_{j_2,t_2,s} \le N_2 \cdot \upsilon^{u}_{j_2,t_2,s} \quad \forall j_2, t_2, s \tag{68}$$

$$\mathrm{LSE2}^{d,\text{con}}_{j_2,t_2,s} \le N_2 \cdot \upsilon^{\text{dn}}_{j_2,t_2,s} \quad \forall j_2, t_2, s \tag{69}$$

$$\upsilon^{\text{LSE2}}_{j_2,t_2,s} = \upsilon^{u}_{j_2,t_2,s} + \upsilon^{\text{dn}}_{j_2,t_2,s} \quad \forall j_2, t_2, s \tag{70}$$

$$\upsilon^{u}_{j_2,t_2,s} + \upsilon^{\text{dn}}_{j_2,t_2,s} \le 1 \quad \forall j_2, t_2, s \tag{71}$$

$$\psi^{\text{LSE2}}_{j_2,t_2,s} - \zeta^{\text{LSE2}}_{j_2,t_2,s} = \upsilon^{\text{LSE2}}_{j_2,t_2,s} - \upsilon^{\text{LSE2}}_{j_2,(t_2-1),s} \quad \forall j_2, t_2, s \tag{72}$$

$$\upsilon^{\text{LSE2}}_{j_2,t_2,s} \ge \psi^{\text{LSE2}}_{j_2,t_2,s} \quad \forall j_2, t_2, s \tag{73}$$

$$\upsilon^{\text{LSE2}}_{j_2,t_2,s} \ge \zeta^{\text{LSE2}}_{j_2,(t_2+1),s} \quad \forall j_2, t_2, s \tag{74}$$

$$\sum_{t_2} \psi^{\text{LSE2}}_{j_2,t_2,s} \le \mathrm{N}^{\text{call}}_{j_2} \quad \forall j_2, t_2, s \tag{75}$$

$$\sum_{\tau = t_2 - \frac{\mathrm{T}^{dur}_{j2}}{\Delta \mathrm{T}} + 1}^{t_2} \psi^{\text{LSE2}}_{j_2,\tau,s} \ge \upsilon^{\text{LSE2}}_{j_2,t_2,s} \quad \forall j_2, t_2, s. \tag{76}$$

Constraints (68)–(76) enforce several constraints related to the LSE2 deployment for reserve provision. Constraints (68)–(71) declare that, once called, a demand LSE2 type can provide only up or down contingency reserve, while (72)–(74) enforce the deployment logic of this type of resource. Equation (75) enforces the maximum number of times each LSE2 can be used to provide contingency reserves, while (76) constraints the maximum duration of each call to be at most $\mathrm{T}^{\text{dur}}_{j_2}$ periods.

The parameters that appear in these constraints are considered known and subject to a specific contract in which the demand responsible entity has agreed with the system operator. To consider more specific constraints, the technical and economic characteristics of the demand side should be known, although the way of implementing them is considered straightforward.

g) Load-following reserves determination:

$$\sum_r \left(\mathrm{WP}_{w,t2,s} - S_{w,t2,s} - W^{\mathrm{sch}}_{w,t_1}\right) = \sum_i \left(r^{\mathrm{dn,wind}}_{i,t_2,s} - r^{\mathrm{up,wind}}_{i,t_2,s} - r^{\mathrm{ns,wind}}_{i,t_2,s}\right) + \sum_{j_1} \left(\mathrm{LSE1}^{d,\mathrm{wind}}_{j_1,t_2,s} - \mathrm{LSE1}^{u,\mathrm{wind}}_{j_1,t_2,s}\right) \quad \forall i, j_1, t_2 \in T^{\mathrm{in}}_2, t_1, s \tag{77}$$

$$\sum_r \left(D^2_{r,t_2} - L^{\mathrm{shed}}_{r,t_2,s} - D^{\mathrm{sch}}_{r,t_1}\right) = \sum_i \left(r^{\mathrm{up,load}}_{i,t_2,s} + r^{\mathrm{ns,load}}_{i,t_2,s} - r^{\mathrm{dn,load}}_{i,t_2,s}\right) + \sum_{j_1} \left(\mathrm{LSE1}^{u,\mathrm{load}}_{j_1,t_2,s} - \mathrm{LSE1}^{d,\mathrm{load}}_{j_1,t_2,s}\right) \quad \forall i, j_1, t_2 \in T^{\mathrm{in}}_2, t_1, s. \tag{78}$$

Constraints (77) and (78) enforce the correct deployment of load-following reserves. Specifically, (77) enforces that if the net accepted wind during the actual operation of the power system is greater than the scheduled during the day-ahead clearing procedure, down reserves should be deployed: decrease in power output of the generating units or/and increase in the LSE of type 1 consumption. The contrary holds when the wind deviation is negative. According to (78), when the load deviation is positive, the units should increase their production or the LSE of type 1 should decrease consumption. The contrary holds if there is a negative load deviation.

III. Tests and Results

A. Illustrative Example

To demonstrate the proposed methodology, the sample system with four generators shown in Fig. 2 is analyzed over a 6-h horizon. It should be noted that all data are conceptual, based on typical values that can be found in the literature [44], in order to serve the illustrative purposes of this section. The technical and economic data for the generators are presented in Tables I and II, respectively. The network topology and the line data were derived from [45]. Without loss of generality, it is assumed that the economic data are constant through the scheduling horizon. Furthermore, all three generators are able to provide up- and down-spinning reserves, but only Units 3 and 4 can provide nonspinning reserve. At the beginning of the scheduling horizon, Units 1 and 2 are already synchronized for 5 h (300 min), providing 300 and 450 MW, respectively. Units 3 and 4 are down for 5 h (300 min). Besides, Unit 1 is considered a must-run unit. The initial conditions are treated within the context of the extension of the scheduling horizon as described in [44], applied here in both time-scales.

Economic and other data concerning the demand side, as well as the wind farm that has installed capacity of 100 MW, are given in Table III. Wind uncertainty is considered through three scenarios (high, moderate, and low), as shown in Table IV. The probabilities of occurrence for each scenario are 0.6 for high (S1), 0.2 for moderate (S2), and 0.2 for low (S3).

The inelastic load in the second stage is presented in Table IV, while the inelastic load considered in the first stage is presented in Table V. It is to be noted that the inelastic load in the second stage can differ up to 10% from the load of the first stage. The inelastic load is considered known in both stages and the relevant data are presented in Tables IV and V. The scheduled LSE1 load can vary up to 20% from the values in parentheses of Table V and can also provide up and down load following reserves within the same limits, while LSE2 follows

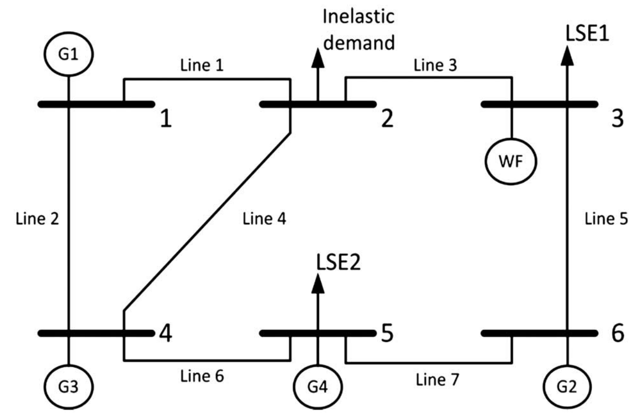

Fig. 2. Network model.

TABLE I
TECHNICAL DATA OF GENERATING UNITS

Unit	P_{max} (MW)	P_{min} (MW)	UT (h)	DT (h)	UT (min)	DT (min)	RU (MW/min)	RD (MW/min)
Unit 1	500	150	3	3	180	180	5	5
Unit 2	450	120	12	12	720	720	15	15
Unit 3	400	40	0	0	20	10	40	40
Unit 4	150	20	0	0	10	10	40	40

TABLE II
ECONOMIC DATA OF GENERATING UNITS

Unit	Marginal costs (€/MWh)	Up reserve offer cost (€/MWh)	Down reserve offer cost (€/MWh)	Non-spinning reserve offer cost (€/MWh)	SUC (€)	SDC (€)
Unit 1	5–7	2	2	–	30 000	5000
Unit 2	9–12	3	3	–	25 000	2000
Unit 3	20–23	6	6	0.5	2000	1000
Unit 4	22–28	7	7	0.5	1000	500

TABLE III
ECONOMIC AND OTHER DATA OF DEMAND SIDE RESOURCES AND FOR OTHERS

	Utility (€/MWh)	Up (€/MWh)	Down (€/MWh)	Paid at call (€)	Number of calls	Duration of call (min)
LSE1	50	5	5	–	–	Continuous
LSE2	–	10	10	40	2	30
V^{LOL}	1000	–	–	–	–	–
V^{S}	1000	–	–	–	–	–

TABLE IV
WIND SCENARIOS AND REAL-TIME INELASTIC LOAD

Time	Wind			Inelastic	Time	Wind			Inelastic
	S1	S2	S3			S1	S2	S3	
1:00	85	58	22	819	4:00	66	63	34	800
1:10	82	49	32	897	4:10	78	65	20	750
1:20	79	53	23	884	4:20	60	61	21	770
1:30	85	56	29	932	4:30	65	63	23	754
1:40	65	44	24	890	4:40	78	63	33	728
1:50	76	57	22	873	4:50	62	57	31	765
2:00	62	62	30	814	5:00	64	62	29	629
2:10	70	59	31	721	5:10	82	45	35	616
2:20	70	65	30	742	5:20	62	35	31	589
2:30	76	61	24	773	5:30	80	48	21	643
2:40	76	46	34	838	5:40	85	54	24	595
2:50	82	49	33	842	5:50	69	48	29	579
3:00	84	63	20	521	6:00	84	42	23	414
3:10	66	50	24	602	6:10	63	52	24	409
3:20	66	36	33	517	6:20	62	44	27	472
3:30	63	30	23	535	6:30	76	39	23	425
3:40	81	61	33	509	6:40	70	35	27	462
3:50	63	35	32	529	6:50	81	36	34	478

TABLE V
SCHEDULED PRODUCTION AND CONSUMPTION (MW)

Time	U1	U2	U3	U4	Wind	LSE 1	LSE 2	Inelastic
1	413	450	201	0	22	96 (80)	90	900
2	469	400	102	0	24	97(90)	120	800
3	460	272	0	0	20	92(100)	110	550
4	500	384	0	0	20	64(80)	80	760
5	463	256	0	0	21	70(70)	70	600
6	327	211	0	0	23	61(60)	50	450

the pattern of the same table, unless it is called to provide contingency reserves, altering its consumption by up to 50% up and down.

It should be noted that the requirement of fixed energy consumption within the scheduling horizon (load pickup) is enforced for the LSE1.

In this study, we consider that the must-run Unit 1 (which is also the unit with the largest capacity) fails at 14:10. Owing to the small size of the test system, transmission line failures would cause major disturbance to power flows and are not studied.

The results for the scheduled production, consumption, and reserves are presented in Tables V and VI. It is clear that the total energy required (expressed by the values in parentheses in Table V) by LSE1 is supplied during the scheduling horizon. Also, it can be seen from Table VI that the contingency is supported by the fast (and expensive) Units 3 and 4 (through nonspinning reserves), as well as from the demand side. The LSE2 responds 50 min after the contingency occurs and the contingency reserves from the LSE2 are used for 60 min (two calls). The response is not immediate because in period 5, the wind scenarios are higher than in period 4, and thus, reserves should also be procured to balance wind production. Thus, LSE2 response is used to relieve the system stress.

TABLE VI
SCHEDULED RESERVES

	Time	1	2	3	4	5	6
Unit 1	U	0	0	0	0	0	0
	U_L	0	0	0	0	0	0
	U_W	0	0	0	0	0	0
	U_C	0	0	0	0	0	0
	D	73	27	74	0	0	0
	D_L	63	21	41	0	0	0
	D_W	10	6	33	0	0	0
	D_C	0	0	0	0	0	0
Unit 2	U	0	0	0	0	0	0
	U_L	0	0	0	0	0	0
	U_W	0	0	0	0	0	0
	U_C	0	0	0	0	0	0
	D	11	49	26	58	71	91
	D_L	11	31	6	32	21	41
	D_W	0	18	20	26	50	50
	D_C	0	0	0	0	0	0
Unit 3	U	0	0	0	0	0	0
	U_L	0	0	0	0	0	0
	U_W	0	0	0	0	0	0
	U_C	0	0	0	0	0	0
	D	70	50	0	0	0	0
	D_L	16	25	0	0	0	0
	D_W	54	25	0	0	0	0
	D_C	0	0	0	0	0	0
	N	0	0	0	440	371	325
	N_L	0	0	0	40	16	28
	N_W	0	0	0	19	0	10
	N_C	0	0	0	381	355	287
Unit 4	U	0	0	0	0	0	0
	U_L	0	0	0	0	0	0
	U_W	0	0	0	0	0	0
	U_C	0	0	0	0	0	0
	D	0	0	0	0	0	0
	D_L	0	0	0	0	0	0
	D_W	0	0	0	0	0	0
	D_C	0	0	0	0	0	0
	N	0	44	80	129	111	40
	N_L	0	44	67	0	27	0
	N_W	0	0	13	10	11	0
	N_C	0	0	0	119	73	40
LSE 1	U_L	32	14	0	0	0	0
	U_W	0	0	0	0	0	0
	D_L	0	2	15	0	0	0
	D_W		9	13	32	14	11
LSE 2	U_C	0	0	0	0	35	0
	D_C	0	0	0	0	0	0
Total upward		32	44	80	569	517	365
Total downward		154	137	128	90	85	102

U, up; D, down; N, nonspinning; L, load; W, wind; C, contingency. Values are in MW.

The results for different wind-scenario outcomes are given in Table VII. To clarify the model operation, we concentrate on the analysis of period 4, during which Unit 1 outage occurs. The scheduled production is 500 MW from Unit 1 and 384 MW from Unit 2. The production scheduled from the wind farm is 20 MW. The LSE1 is scheduled to be provided with 64 MW (with nominal consumption 80 MW) for this hour. LSE2 consumes 80 MW and the inelastic load is 760 MW. During this period, the inelastic load has a maximum increase at 4:00 (by 40 MW) and the maximum decrease

TABLE VII
REAL-TIME GENERATION AND CONSUMPTION (MW)

Time	S1						S2						S3					
	U1	U2	U3	U4	LSE1	LSE2	U1	U2	U3	U4	LSE1	LSE2	U1	U2	U3	U4	LSE1	LSE2
1	350	439	131	0	96	90	350	448	149	0	96	90	350	448	185	0	96	90
1:10	400	450	151	0	96	90	400	450	184	0	96	90	400	450	201	0	96	90
1:20	410	450	131	0	96	90	413	450	154	0	96	90	413	450	184	0	96	90
1:30	404	450	147	0	64	90	413	450	167	0	64	90	413	450	194	0	64	90
1:40	413	450	148	0	96	90	413	450	169	0	96	90	413	450	189	0	96	90
1:50	413	439	131	0	96	90	413	439	150	0	96	90	413	439	185	0	96	90
2	463	415	77	0	83	120	463	415	77	0	83	120	463	422	102	0	83	120
2:10	448	379	52	0	108	120	448	390	52	0	108	120	448	391	77	0	106	120
2:20	469	379	52	0	108	120	469	384	52	0	108	120	469	391	77	0	105	120
2:30	469	404	52	0	108	120	469	419	52	0	108	120	469	422	77	0	99	120
2:40	469	404	77	40	108	120	469	422	89	40	108	120	469	422	101	40	108	120
2:50	463	404	77	44	108	120	469	419	89	44	108	120	469	422	102	44	108	120
3	413	254	0	0	120	110	419	269	0	0	120	110	419	272	0	40	120	110
3:10	445	254	0	67	120	110	460	255	0	67	120	110	460	272	0	76	120	110
3:20	395	246	0	40	120	110	421	250	0	40	120	110	448	266	0	0	120	110
3:30	445	257	0	0	120	110	460	272	0	0	117	110	460	272	0	0	110	110
3:40	412	246	0	0	120	110	432	246	0	0	120	110	440	266	0	0	120	110
3:50	450	246	0	0	120	110	460	264	0	0	120	110	460	266	0	0	119	110
4	500	370	40	0	96	80	500	373	40	0	96	80	500	384	58	0	96	80
4:10	–	348	381	119	96	80	–	361	381	119	96	80	–	374	381	119	64	80
4:20	–	376	391	119	96	80	–	375	391	119	96	80	–	384	400	124	79	80
4:30	–	365	381	119	96	80	–	367	381	119	96	80	–	378	400	129	96	80
4:40	–	326	381	119	96	80	–	341	381	119	96	80	–	352	400	119	96	80
4:50	–	374	386	119	96	80	–	379	386	119	96	80	–	384	400	123	93	80
5	–	227	357	100	84	35	–	229	357	100	84	35	–	256	371	92	84	35
5:10	–	209	371	73	84	35	–	246	371	73	84	35	–	256	371	73	84	35
5:20	–	218	355	73	84	35	–	245	355	73	84	35	–	245	355	77	84	35
5:30	–	211	371	100	84	35	–	243	371	100	84	35	–	256	371	100	70	35
5:40	–	201	355	73	84	35	–	232	355	73	84	35	–	251	355	84	84	35
5:50	–	201	355	73	84	35	–	222	355	73	84	35	–	235	355	79	84	35
6	–	125	287	40	72	50	–	167	287	40	72	50	–	175	287	40	61	50
6:10	–	141	287	40	72	50	–	152	287	40	72	50	–	170	297	40	72	50
6:20	–	183	309	40	72	50	–	201	309	40	72	50	–	211	316	40	72	50
6:30	–	144	287	40	72	50	–	181	287	40	72	50	–	186	287	40	61	50
6:40	–	175	299	40	72	50	–	210	299	40	72	50	–	211	306	40	72	50
6:50	–	164	315	40	72	50	–	209	315	40	72	50	–	211	315	40	72	50

occurs at 4:40 (by 32 MW). To balance this intra-hour load variation, load-following reserves are procured. Specifically, the load decrease is fully covered by Unit 2 (32 MW down-spinning load-following reserve). The intra-hour load increase is covered by Unit 3 that offers nonspinning reserves.

The maximum wind increase that is possible during this period occurs at 14:10 and 14:40, corresponding to 58 MW. To cover this fluctuation, 26 MW of up-spinning reserve are procured by Unit 2. Furthermore, LSE1 increases its consumption by 32 MW, offering down reserve. It is to be noted that in order to cover the wind fluctuations in other scenarios and intra-hour intervals during periods 4, 19, and 10 MW of nonspinning reserve are scheduled by Units 3 and 4, respectively. On the other hand, since the scheduled wind production from the wind farm is 20 MW (i.e., equal to the lowest value during this period) no reserves are needed to cover this deviation. It should be noted that no-wind production is spilled in any scenario.

As stated before, the contingency occurs at 14:10. Unit 1 is scheduled to provide 500 MW (technical maximum) during that hour. When the contingency occurs, this amount of energy has to be replaced by the other system resources. Fast Units 3 and 4 respond with 381 and 119 MW scheduled nonspinning reserve.

TABLE VIII
ENERGY AND RESERVES COSTS PROCURING RESERVES FROM DEMAND SIDE OR ONLY FROM GENERATION SIDE

	Energy cost (€)	Reserves cost (€)
Reserves procured also from demand-side (case 1).	39 559.029	2756.007
Reserves procured only from generation-side (case 2).	41 199.282	3384.714

As a further test case (case 2), we consider that the total load of the system is inelastic; thus, the needed reserves have to be procured only from the generation side.

In Table VIII, the costs of procuring reserves from the generation side as well as the cost of energy are presented, comparing the previously presented case (with responsive demand—case 1) with the case in which reserve services can be procured only by generation side.

A decrease in the cost of producing energy and committing reserves from the generation-side is evident in case 1. The reduction in energy costs is caused because of the different UC schedule, and especially due to the expensive Unit 4 that in case 2 is scheduled to provide a large amount of energy (126 MW) in period 14. In case 1, this unit is not scheduled to provide energy. The reduction in the reserve commitment cost is related

TABLE IX
ENERGY AND RESERVES COSTS FOR DIFFERENT LSE1 FLEXIBILITIES

Flexibility LSE1 (%)	Energy cost (€)	Reserves cost (€)	Demand-side reserve cost (€)	Total cost of scheduled energy and reserves (€)
0	41 199.282	3384.714	–	44 583.996
10	39 502.141	2959.567	402	42 863.708
20	39 559.029	2773.507	760	43 092.536
30	39 565	2611.115	1090	43 266.115
40	39 425.500	2295.576	1380	43 101.076
50	39 311	2157	1460	40 773.157

TABLE X
ENERGY AND RESERVES COSTS FOR DIFFERENT LSE2 FLEXIBILITIES

Flexibility LSE2 (%)	Energy cost (€)	Reserves cost (€)	Demand-side reserve cost (€)	Total cost of scheduled energy and reserves (€)
0	41 199.282	3384.714	–	44 583.996
10	41 048.853	3382.714	80	44 511.567
20	40 912.853	3382.714	160	44 455.567
30	40 776.853	3382.714	240	44 399.567
40	40 646.425	3382.714	320	44 349.139
50	40 518.425	3371.711	400	44 290.136

mainly to the load-following reserve, which in case 1 is handled by the LSE1. From Tables III and VI, it can be concluded that the total cost to be paid for demand-side reserves is 1060 €. Thus, the net economic impact of the responsive demand is a cost reduction in 1208.96 €.

Finally, the impact of having different responsive demand capacities is examined. First, it is considered that LSE2 does not provide contingency reserves, and LSE1 up and down consumption alteration limits are spanning from 0% to 50%, in order to assess the performance of load-following reserves procurement from the demand side.

The results are presented in Table IX. It can be seen that procuring reserves from responsive demand is economically beneficial for the system in any case. Although the LSE1 consumption contributes increase in the social benefit (through the LSE1 utility), the system operator schedules as much down reserve from the LSE1 as possible. That is the reason why the total cost increases or decreases when the flexibility of the LSE1 increases.

The impact of providing contingency reserves from demand-side resources is then investigated, considering that LSE1 is not available to provide load-following reserves. LSE2 capability of altering its consumption is increased from 0% to 50%.

The relevant results are presented in Table X. In contrast with the previous tests, it is clear that contingency reserves procurement from the demand side reduces both energy and generation-side reserves cost, since it is not linked with any utility because it is paid when it is called to provide contingency reserves.

B. 24-Node System

To investigate the scalability and generalize the conclusions drawn from the proposed methodology, it is also applied to a larger-scale test system and several studies are performed to evaluate the impact of introducing demand-side reserves.

The 24-node system that is analyzed here is based on the single area version of the IEEE Reliability Test System-1996 [46] and all the data are derived from [6]. It should be noted that the ramp rates of the generators were doubled, because the original Test System is designed for hourly intervals and thus it is difficult to achieve feasible solutions for the intra-hour time steps. Given the size of the problem, the intra-hour time step is 15 min.

All the tests that are presented in this section were performed for a horizon of 12 h. In order to reduce the size of the problem, generators have been grouped by type and bus, so that only one set of binary variables is used to determine the commitment status of one group of units. Grouping generating units by type and node is a technique that is commonly used in the relevant literature (e.g., [6] and [18]). Its aim is to reduce the number of binary variables related to UC. The idea behind this simplification is that units of the same technology (e.g., hydro, nuclear, etc.) that are connected at the same node are controlled using the same binary variables. The maximum power output is the sum of each single unit's maximum power output and the minimum power output is the sum of each single unit's minimum power output. The reduction in the computational burden depends on the number of units and their location and not on the number of nodes.

Hydro and nuclear units are considered must-run units. Also, only units at nodes 7, 13, 15, and 16 are considered technically capable of providing nonspinning reserves. Nonspinning reserves are assumed to be scheduled at a cost equal to 20% of the generator's highest bid. Besides, all the units offer up- and down-spinning reserves at a cost equal to 25% of their highest bid.

Furthermore, the wind farm is assumed to be located at node 10 with an installed capacity of 200 MW. In order to force the system operator to integrate as much available energy, a very high value for the wind spillage cost is adopted, equal to 3000 €/MWh.

To adequately describe wind uncertainty, a sufficient number of scenarios have to be generated. Publicly available data [47] have been used in order to generate 10 hourly scenarios with a scenario generation technique based on the roulette wheel mechanism (RWM) [48].

The intra-hour deviations for the wind production have a mean average value equal to the hourly value of the wind power production scenarios and can deviate up to 3% for the intra-hour intervals. The scenarios normalized with respect to the capacity of the wind farm are presented in Fig. 3 and are equiprobable.

To enforce the security of the power system, the system operator does not allow involuntary load shedding.

For the sake of simplicity, no intra-hour load variations are considered. The LSE1 that are committed to provide load-following reserves offers this service at a value of 5 €/MWh. Furthermore, the utility of the LSE of type 1 is considered to be constant and omitted from the objective, so that the actual total expected cost is evaluated. The data for the LSE2 are the same such as in the six-node system case, with the only difference that the cost of scheduling contingency reserves from

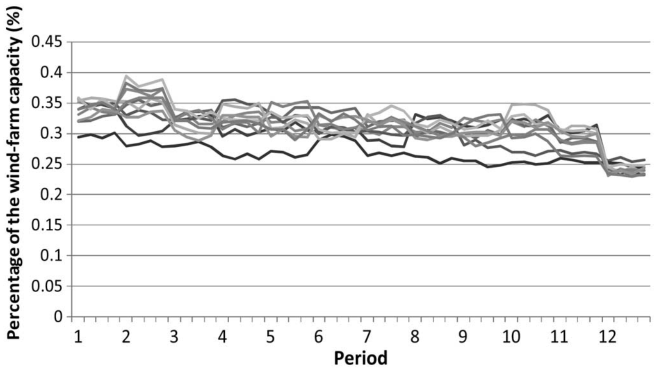

Fig. 3. Wind-power scenarios.

TABLE XI
EVALUATION OF THE DEMAND-SIDE LOAD-FOLLOWING RESERVES

	Flexibility (%)	Energy cost (€)	Generation-side reserve cost (€)	Demand-side reserve cost (€)	Expected spilled wind energy (MWh)
Base case	0	167 090	0	–	107.170
LSE of type 1 at bus#20	10	167 203	0	543	17.900
	20	166 789	183	942	2.700
	30	166 295	183	979.500	1.250
LSE of type 1 at bus#18	10	166 520	183	979.500	1.250
	20	165 280	183	1017.500	0.520
	30	164 349	183	973	1.440
LSE of type 1 at buses #20 and #18	10	165 956	183	979.500	1.250
	20	164 671	183	1018.500	0.515
	30	162 869	183	1036	0.260

LSE2 is 0.25 €/MWh. The relatively low prices assumed for the reserves procured by LSE1 are based on the fact that in case of LSE1, the energy is not lost when it provides load-following reserves, but is recovered in other periods. Also, the LSE2 provides very low cost contingency reserves due to the fact that it is separately paid when it is called and such calls are infrequent.

In the first set of tests (Set 1), it is considered that no contingency occurs. The impact of load-following reserves procurement from the demand side is evaluated considering that the demand located at bus 20 (4.5% of the system load) can provide load-following reserves with flexibility that is spanning from 10% to 50%. Then the same tests are performed for the demand located at bus 18 (11.7% of the system load). Finally, it is assumes that loads located at buses 20 and 18 have both the ability to provide load-following reserves. The relevant results are presented in Table XI.

The expected spilled wind energy is calculated as the sum of the spilled available wind power production over the horizon, divided by the number of the intra-hour intervals and multiplied by the probability of the occurrence of the scenarios (since they are equiprobable).

It is clear from the results of Table XI that the incorporation of load-following demand-side reserves facilitates the integration of wind energy into the power system.

It can be noticed that as the ability of the elastic loads to deviate from their nominal power increases, the cost of the energy

TABLE XII
EVALUATION OF THE DEMAND-SIDE CONTINGENCY RESERVES

	Energy cost (€)	Generation-side reserve cost (€)	Demand-side reserve cost (€)
Base case	167 090	10 590	0
LSE of type 2 at bus #3	167 090	10 238	20
LSE of type 3 at bus #18	167 090	10 181.5	66
LSE of type 2 at buses #3 and #18	167 090	9429.2	101.5

that is produced by the generators decreases and it is at the minimum when the loads at buses 18 and 20 are providing load following reserves with 30% flexibility.

The wind power that is spilled (and that is also penalized) follows the same trend, in general. It is to be stated that in most of the simulations of this test set, nonspinning reserve was scheduled from units located at bus 15 (30 MW) during period 11. In the same period, the greatest increase in the consumption of the LSE of type 1 loads is noticed.

In the second set of tests (Set 2), it is considered that the outage of the must-run nuclear unit located at bus 18 (400 MW) occurs at period 7:30. Then, during period 9:30, the transmission line 33 with capacity 1000 MW fails. These two contingencies have a serious impact on system operation. First, it is assumed that no contingency-reserves can be procured by the demand side.

The performance of the demand-side contingency reserves is evaluated by consecutively considering loads at buses 3 (6.3% of the system load) and 18 (11.7% of the system load) being able to alter their consumption by 50%. Finally, both loads of these buses are considered LSE of type 2 with the same flexibility.

The results are presented in Table XII. The scheduled energy cost is not affected after the integration of the LSE of type 2, since this type of responsive demand is scheduled to consume its nominal power, unlike the LSE of type 1 that generally contributes in the energy cost reduction through its energy provision need reallocation.

The demand that is located at bus 3 is called two consecutive times and offers 80 MW up contingency reserve during period 10 that corresponds to the highest system loading condition. This leads to less reserve scheduled during that hour that would be provided by units that operate at a high marginal cost power block. Next, the demand that is located at bus 18 is called one time as soon as the contingency occurs to provide 115 MW of contingency reserve. Also, it is called during period 11 that corresponds also to a high total system load in order to reduce the generation-side reserve cost. Furthermore, when both loads at buses 3 and 18 are available for contingency reserve procurement, the demand at bus 18 offers 115 MW in period 7 and 149 MW of up reserve in period 11.

Similarly, the demand at bus 3 offers 62 MW during period 7 and 80 MW during period 11. This leads to a reduced need of generation-side reserves as soon as the contingency occurs and when the system load is at its peak. It is clear from the results

TABLE XIII
EVALUATION OF THE COMBINED EFFECT OF LSE OF TYPE 1 AND 2

	Energy cost (€)	Generation-side reserve cost (€)	Demand-side reserve cost (€)	Expected spilled wind energy (MWh)
LSE of type 2 at buses #3 and #18	167 090	9429.2	101.5	107.17
Additional LSE of type 1 at bus #20	166 295	9612.2	1081	1.25

TABLE XIV
COMPUTATIONAL STATISTICS

	Equations	Variables	Discrete variables	Time (s)	Duality gap (%)
6-Node system					
	32 488	268 853	2731	237	0
24-Node system					
Base case without CON	572 248	2 236 139	32 688	93	0
Base case with CON	560 448	2 233 279	32 028	151	0
Set 1	658 731	2 240 623	33 648	153	0
Demand at bus #18 and #20 are LSE of type 1					
Set 2	554 908	2 233 279	32 028	635	10^{-4}
Demand at bus #18 is an LSE of type 2					
Set 3	550 416	2 238 035	34 428	342	0

that as the demand-side contingency reserve capacity increases, the generation-side contingency reserve cost is reduced.

As a final study (Set 3), it is considered that loads at buses 18 and 3 are available for contingency reserve procurement and the load of bus 20 can provide load-following reserves with 30% flexibility. This case is compared with the case in which the load of bus 20 is inflexible, already presented.

The relevant results are presented in Table XIII. The energy cost reduction in the first case is a result of the increased wind power integration and of the reallocation of the energy provision of the LSE of type 1 located at bus 20. The scheduled reserve costs are higher because 979.5 € are spent on load-following reserve, while nonspinning reserves are scheduled from Unit 5 in period 11. Besides, this increase in the reserve costs allows a greater portion of the wind power generation to be integrated into the system.

C. Computational Statistics

The proposed model is solved using MILP techniques in GAMS 24.0.2 software package [49] by CPLEX 12 solver. The computer used for the simulations is a workstation with two 3.47 GHz six-core processors and 96 GB of RAM, running 64 bit windows operating system. The relevant results are presented in Table XIV. It should be noted that for each test set, the statistics for the computationally worst case have been presented. Also, the relative duality gap is set to 0% for all test cases, except for the case presented for Set 2 for which it set to 10^{-4}. It is obvious that the size of the problem by means of the number of equations and variables is not necessarily a determinant factor for the computational burden linked to a MILP problem. For instance, the six-node system requires more computational effort than several tests performed on the 24-node system, mainly because the network constraints are binding in the first case.

IV. CONCLUSION

In this study, a two-stage stochastic programming model has been developed in order to specify the optimal response of a system facing different sources of uncertainty, namely intra-hour load and wind generation deviations, transmission line, and generating units outages. As seen from the illustrative test case, although using different time-scales may increase the modeling complexity, the computational burden, and the amount of output data, it provides a better insight into the actual operation of a power system. It should be stated that through the proposed methodology, it becomes clear that the integration in large-scale of volatile power resources, such as wind, directly affects the reliability of a power system. System operators should consider developing new AS that would be more specific, targeted to balance the negative effects of the uncertainty and variability introduced by different factors. Extensive simulations presented in this paper allowed concluding that by exploiting the advantages that the demand side can offer, the system gains a flexible asset to cope with normal operations as well as with emergency events in an economic way.

The applicability of the presented methodology depends on the computational time required to solve the optimization problem. Measures that can be applied to reduce the computational burden include the following.

1) Proceed in the solution of the problem with a relative duality gap greater than 0%. This will affect the quality of the solution, and thus, this measure should be carefully applied, after an acceptable trade-off between solution time and quality has been determined.
2) Utilize modern computing techniques such as grid and cloud computing. Since there are already companies that provide computational power at affordable prices, this proposal promises tractability even for large-scale mathematical programming problems. Also, commercially available software has evolved to support such techniques, recently.
3) The technological advances are of unquestionable importance, though special attention should be given in the efficient modeling of a problem. Decomposition techniques, such as Bender's decomposition, allow exploiting efficiently the developments in the informatics field.

The proposed approach can be extended to consider load deviations and contingencies through scenarios. The concept of utilizing different time-scales for every stage of the model allows the development of multistage stochastic programming models. Such models could be useful in examining the interaction between different market structures in several time-scales as well as assessing the value of the incomplete information about random variables (e.g., wind forecasts and load forecasts) available at every decision making point. The above topics will be considered in future studies of the authors.

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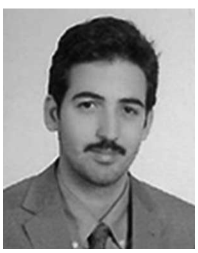

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