Market Clearing Model for Microgrids with Probabilistic Security Criteria: Formulation and Implementation

Modelo de Despacho para Microrredes con Criterios de Seguridad Probabilísticos: Formulación e Implementación

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ABSTRACT

This paper proposes an energy-reserve market clearing model for microgrids considering probabilistic security criteria. The probabilistic security criteria include pre-selected scenarios associated to unreliability of generators and uncertainties caused by the stochastic behavior of loads and renewable units. In contrast to traditional deterministic reserve-constrained market clearing models, this paper determines the optimal amount of reserve as the point at which the sum of its operating costs and the expected cost of load shed reach a minimum. The proposed model is formulated as a two-stage stochastic programming problem, where the first stage represents the hour-ahead energy-reserve market, and the second stage the balancing market.

An energy management procedure is developed in order to implement the stochastic programming problem on the real microgrid ATENEA located at the installations of the National Renewable Energy Centre of Spain. The generation and reserve schedules obtained with the stochastic approach are assessed and compared with those of a purely deterministic security-constrained case.

Keywords: Market clearing, microgrids, mixed integer nonlinear programming, probabilistic security, reserve, stochastic programming.

RESUMEN

Este artículo propone un modelo de despacho de energía-reserva para microrredes considerando criterios de seguridad probabilísticos. Los criterios de seguridad probabilísticos incluyen escenarios preseleccionados asociados a la falla de generadores y a las incertidumbres causadas por el comportamiento estocástico de cargas y unidades renovables. A diferencia de los modelos de despacho tradicionales con restricciones de reserva determinísticas, este artículo determina la cantidad óptima de reserva como el punto en el que la suma de sus costos de operación y el costo esperado del deslastre de carga alcanza un mínimo. El modelo propuesto es formulado como un problema de programación estocástica de dos etapas, donde la primera etapa representa el despacho de energía-reserva de la hora siguiente, y la segunda etapa el mercado de balances.

Un procedimiento de gestión de la energía es desarrollado con el fin de implementar el problema de programación estocástica en la microrred ATENEA ubicada en las instalaciones del Centro Nacional de Energías Renovables de España. Los programas de generación y reserva obtenidos con el enfoque estocástico se evaluaron y compararon con aquellos obtenidos de un caso con restricciones de seguridad puramente determinísticas.

Palabras clave: Despacho, microrredes, programación no lineal entera mixta, seguridad probabilística, reserva, programación estocástica.

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Nomenclature

Indices.

i	Index of dispatchable generators, from 1 to *I*.
j	Index of nondispatchable generators, from 1 to *J*.
m	Index of buses, from 1 to *M*.
t	Index of time periods, from 1 to *T*.

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x Index of net load scenarios, from 1 to *X*.

y Index of unit outage scenarios, from 1 to *Y*.

z Index of aggregated scenarios, from 1 to *Z*.

Variables.

$f_t(m,s)$ Power flow through line *(m,s)* in period *t*.

g_{it} Power output of dispatchable generator *i* in period *t*.

g_{jt} Power output forecast of nondispatchable generator *j* in period *t*.

$l_{mt}^{sh}(z)$ Involuntarily shed load at bus *m* in period *t* and aggregated scenario *z*.

r_{it}^{up} Up reserve capacity of dispatchable generator *i* in period *t*.

r_{it}^{dw} Down reserve capacity of dispatchable generator *i* in period *t*.

r_{it}^{su} Start-up reserve capacity of dispatchable generator *i* in period *t*.

r_{mt}^{up} Up reserve capacity of flexible demand at bus *m* in period *t*.

r_{mt}^{dw} Down reserve capacity of flexible demand at bus *m* in period *t*.

u_{it} Binary variable (1 if dispatchable generator *i* is online in period *t*; 0 otherwise).

$y_{it}^{up}(z)$ Up reserve deployed by dispatchable generator *i* in period *t* and aggregated scenario *z*.

$y_{it}^{dw}(z)$ Down reserve deployed by dispatchable generator *i* in period *t* and aggregated scenario *z*.

$y_{it}^{su}(z)$ Start-up reserve deployed by dispatchable generator *i* in period *t* and aggregated scenario *z*.

$y_{mt}^{up}(z)$ Up reserve deployed by flexible demand at bus *m* in period *t* and aggregated scenario *z*.

$y_{mt}^{dw}(z)$ Down reserve deployed by flexible demand at bus *m* in period *t* and aggregated scenario *z*.

Parameters.

C_{it} Offer cost of dispatchable generator *i* in period *t*.

C_{it}^{NL} No-load offer cost of dispatchable generator *i* in period *t*.

C_{it}^{SU} Start-up offer cost of dispatchable generator *i* in period *t*.

C_{jt} Offer cost of nondispatchable generator *j* in period *t*.

C_{mt} Offer benefit of flexible demand at bus *m* in period *t*.

C_{it}^{R} Offer cost of up/down reserve capacity of dispatchable generator *i* in period *t*.

C_{mt}^{R} Offer cost of up/down reserve capacity of flexible demand at bus *m* in period *t*.

C_{it}^{O} Cost due to outage of dispatchable generator *i* in period *t*.

C_{jt}^{O} Cost due to outage of nondispatchable generator *j* in period *t*.

d_{mt} Load forecast at bus *m* in period *t*.

D_{mt}^{max} Maximum power that can be consumed by flexible demand at bus *m* in period *t*.

D_{mt}^{min} Minimum power required by flexible demand at bus *m* in period *t*.

E_{m}^{hour} Minimum hourly energy consumption for flexible demand at bus *m*.

$F^{max}(m,s)$ Maximum capacity of line *(m,s)*.

G_i^{max} Capacity (maximum power output) of unit *i*.

G_i^{min} Minimum power output of unit *i*.

$p(z)$ Probability of aggregated scenario z.

$v_{it}(z)$ Binary parameter (0 if dispatchable generator *i* fails in period *t* and aggregated scenario *z*; 1 otherwise).

$v_{jt}(z)$ Binary parameter (0 if nondispatchable generator *i* fails in period *t* and aggregated scenario *z*; 1 otherwise).

V_{mt}^{LOL} Value of lost load at bus *m* in period *t*.

$\Delta l_{mt}(z)$ Net load forecast error at bus *m* in period *t* and aggregated scenario z.

φ_t Duration of time period *t*.

Sets.

Λ Set of transmission lines.

M_I Mapping of the sets of dispatchable units into the set of buses.

M_J Mapping of the sets of nondispatchable units into the set of buses.

Remark: When augmented with the argument *(z)*, the above variables and parameters represent their value given that stochastic scenario z has occurred in the microgrid.

Introduction

The integration of renewable sources into microgrids represents one of the biggest challenges to their operators and planners (IEEE, 2011), (Luna et al, 2011). In order to accommodate the unpredictable nature of renewable power, the generation and demand scheduled in an electricity market need to be modified during the real-time operation of the microgrid (Katiraei et al, 2008). The spinning reserve (SR) is the service traded in the market to materialize physically the required adjustments necessary to maintain a secure network operation (Gooi et al, 1999).

Increasing the SR requirement can reduce the probability and severity of involuntary load shedding. However, providing SR has a cost because additional units may be committed and other units may operate below their optimal output. Thus, determining the optimal amount of SR to be provided as a function of the system conditions represents a relevant issue to be solved. Traditional market clearing processes adopt a deterministic approach to estimate the reserve capacity needs. These processes ignore the stochastic nature of the events that call for balancing energy, and consequently, reserve requirements are estimated independent of both the probability of stochastic scenarios affecting the power system and their impact on system operation costs.

In (Kirschen, 2002) it is suggested that power system security analysis methods should evaluate the “credibility” of scenarios and their “expected” consequences by means of probabilistic methods. Various probabilistic approaches have been developed for optimizing the SR required in a power system under stochastic scenarios. Reference (Ortega & Kirschen, 2010) assumes that the reserve market is independent of the energy market, which ignores the strong coupling between the supply of energy and the provision of reserve capacity. In microgrids, the reserve cost may become very significant due to their highly stochastic operation, therefore the use of a simultaneous energy and reserve market clearing procedure allows avoiding uneconomical out-of-merit operation, the start-up of extra units, as well as unnecessary load shedding. In (Wang & Gooi, 2011) and (Liu & Tomsovic, 2012) it is proposed an energy-reserve day-ahead scheduling model that considers probabilistic methods for estimating the SR requirement under equipment failure and uncertainties caused by load and nondispatchable units. These approaches do not clear the balancing market in advance of the realization of the scenarios involved, which is necessary to evaluate the real-time reserve deployment actions. References (Bouffard et al, 2005a), (Bouffard et al, 2005b), (Bouffard et al, 2008), (Morales et al, 2009), (Ruiz et al, 2009) and (Papavasiliou et al, 2011) formulate a day-ahead and balancing market clearing model with stochastic security. These approaches clear the electricity markets in advance of the realization of the scenarios represented generally by unreliability of units or by aggregated demand and wind uncertainty.

All these models do not consider the simultaneous occurrence of the main stochastic scenarios involved in a power system; they do not include the flexible actions of microgrids that permit to improve the security, reliability, quality and efficiency of the system; and these market clearing formulations are not implemented and analyzed on real power systems.

This paper proposes a multi-period energy-reserve market clearing procedure with unit commitment for microgrids considering probabilistic security criteria. The procedure is formulated as a two-stage stochastic programming problem (Birge and Louveaux, 1997). The contributions of this paper are:

1. Introducing the flexibility actions of microgrids associated to battery management and demand response programs into the market clearing formulation.
2. Including a reserve valuation method into the stochastic programming problem that determines the economically optimal level of reserve capacity and reserve deployment within a microgrid. This method permits to optimally manage the failure of units and the uncertainty associated to loads and renewable units.
3. Implementing and testing the market clearing problem on a real network, microgrid ATENEA (Cener, 2015).

The rest of this paper is organized as follows. Section II formulates the market clearing model as a mixed integer nonlinear programming problem. Section III describes in detail the microgrid ATENEA. Section IV presents the energy management procedure and provides results of its implementation on the real microgrid. Section V summarizes the paper with conclusions and discussion.

Market Clearing Model

Description.

A market clearing model for microgrids, that adopts a probabilistic security approach to estimate the reserve capacity needs, is formulated. This model defines the optimal amount of SR to be provided as the point at which the sum of its operating costs and the expected cost of load shed reach a minimum.

The market clearing model is a two-stage stochastic programing problem. The first stage involves the hour-ahead market, which takes place several minutes in advance and settles contracts to energy delivery for the next hour in m-min intervals. The second stage considers the balancing market that serves to competitively settle the energy adjustments required to ensure the constant balance between electricity supply and demand. The balancing market takes place a few seconds before energy delivery and constitutes the last market mechanism to balance production and consumption. This market is particularly relevant for microgrids because of scenarios associated to unreliability of units (Billinton & Allan, 1996) and uncertainties caused by the stochastic behavior of loads and renewable units (e.g., wind and solar power producers).

The coexistence of both markets is well-justified. On the one hand, the hour-ahead market is useful for those power plants that need advance planning in order to efficiently and reliably adjust their production levels. This market considers decisions associated to commitment states of units, and the scheduled energy and reserve capacity throughout the scheduling horizon. On the other hand, the balancing market constitutes a competitive mechanism to efficiently cope with the energy imbalances by allowing flexible firms to adjust their hour-ahead positions. This market considers decisions associated with the deployment of reserve, and the involuntary load shedding in each scenario.

Reserves are either of the up/down or start-up type. Generation-side up/down reserve is provided by committed generators only, while start-up reserve involves changes in the scheduling status of generators. For instance, a generator that is scheduled off can provide start-up reserve if it can be turned on to produce energy within the scenario occurrence. For a consumer, providing up-going reserve implies being ready to voluntarily decrease its level of consumption within the scenario occurrence (Parvania & Fotuhi-Firuzabad, 2010). In the case of down-going reserve, consumers providing this service would be asked to increase their consumption level.

A reasonable way to compute reserve needs using a probabilistic approach is through the expected load not served (ELNS). The ELNS is a stochastic security metric that represents the average amount of energy not supplied as a result of load shedding actions. It is presented as a weighted average energy value that accounts for the probability of uncertain factors and the damage that these factors cause to the system in the form of involuntary curtailed load. The load shedding actions are involuntary as opposed to voluntary demand reduction offered as up-reserve. Moreover, the ELNS can be expressed linearly, and hence, easily included and penalized inside the objective function.

$$ELNS_{mt} = \sum_{z \in Z} p(z) \cdot l_{mt}^{sh}(z) \qquad (1)$$

The SR requirements are determined based on the cost of its provision and the benefit derived from its availability, i.e., ELNS. This way, the amount of reserve that is scheduled matches the value it provides to system users.

Problem formulation.

The objective function aims at minimizing the expected cost, which includes both the cost related to the hour-ahead electricity dispatch and the expected cost of the anticipated balancing actions to be taken during the real-time operation of the microgrid. The optimization problem is solved using mixed integer nonlinear programming methods, and the objective function is stated in equation (2). The objective function to be minimized groups separately those terms representing the costs pertaining to the energy-reserve dispatch [from line 1 to line 4], and those representing the expected costs needed to keep the microgrid balanced under the full set of scenarios considered [from line 5 to line 8].

$$\begin{aligned}
&\sum_{t=1}^{T}\varphi_t\Bigg[\sum_{i=1}^{I}\left(C_{it}\cdot g_{it}+C_{it}^{NL}\right)+\sum_{j=1}^{J}C_{jt}\cdot g_{jt}\\
&\quad+\sum_{i=1}^{I}C_{it}^{R}\cdot\left(r_{it}^{up}+r_{it}^{dw}+r_{it}^{su}\right)\\
&\quad+\sum_{m=1}^{M}C_{mt}^{R}\cdot\left(r_{mt}^{up}+r_{mt}^{dw}\right)\Bigg]\\
&+\sum_{t=1}^{T}\sum_{i=1}^{I}C_{it}^{SU}\\
&+\sum_{z\in Z}p(z)\Bigg\{\sum_{t=1}^{T}\varphi_t\Bigg[\sum_{i=1}^{I}C_{it}\cdot\left(y_{it}^{up}(z)-y_{it}^{dw}(z)+y_{it}^{su}(z)\right)\\
&\quad+\sum_{m=1}^{M}C_{mt}\cdot\left(y_{mt}^{up}(z)-y_{mt}^{dw}(z)\right)\\
&\quad-\sum_{i=1}^{I}C_{it}^{O}(z)-\sum_{j=1}^{J}C_{jt}^{O}(z)\\
&\quad+\sum_{m=1}^{M}V_{mt}^{LOL}\cdot l_{mt}^{sh}(z)\Bigg]\Bigg\}
\end{aligned}\tag{2}$$

It is assumed that renewable producers are not competitive agents, and consequently, this generation is considered as a negative demand, which is equivalent to state that $C_{jt}=0$.

The objective function is subject to constraints pertaining to both hour-ahead and balancing market (Morales et al, 2014), that describe the operational rules of dispatchable units and flexible demands.

First-Stage Constraints Pertaining to the Hour-Ahead Market Operation (Not Depending on Scenario z).

Power Balance:

$$\begin{aligned}
d_{mt}=&\sum_{i:(i,m)\in M_I}g_{it}+\sum_{j:(j,m)\in M_J}g_{jt}\\
&-\sum_{s:(m,s)\in\Lambda}f_t(m,s),\ \forall m,\forall t.
\end{aligned}\tag{3}$$

Due to the technical and operational conditions of distribution networks, the power flow relation $f_t(m,s)$ uses the nonlinear ac load flow model.

Capacity limits:

On the one hand, the power production and reserve capacity of a dispatchable generator is ultimately conditioned by its capacity (maximum power output) and minimum power output, that is:

Up/Down Reserve:

$$g_{it}+r_{it}^{up}\le G_i^{max}\cdot u_{it},\ \forall i,\forall t.\tag{4}$$

$$g_{it}-r_{it}^{dw}\ge G_i^{min}\cdot u_{it},\ \forall i,\forall t.\tag{5}$$

Start-Up Reserve:

$$0\le r_{it}^{su}\le G_i^{max}\cdot(1-u_{it}),\ \forall i,\forall t.\tag{6}$$

On the other hand, the change in the scheduled load of flexible demand at bus *m* in period *t* is bounded above and below by its maximum and minimum load levels, which is formulated mathematically by the next constraints:

$$d_{mt}-r_{mt}^{up}\ge D_{mt}^{min},\ \forall m,\forall t.\tag{7}$$

$$d_{mt}+r_{mt}^{dw}\le D_{mt}^{max},\ \forall m,\forall t.\tag{8}$$

Second-Stage Constraints Pertaining to the Balancing Market Operation (Depending on Scenario z).

Power Balance:

The second-stage power balance constraint, described in equation (9), groups separately those terms representing the real-time power variations because of scenarios associated to unit outages and uncertainties caused by the stochastic behavior of net load forecast error (difference between the load forecast error and the power output forecast error of renewable units) [from line 1 to line 2], and those representing the power balancing actions required to counteract the mentioned variations [from line 3 to line 5].

$$\begin{aligned}
&\sum_{i:(i,m)\in M_I}g_{it}\cdot(1-v_{it}(z))\\
&+\sum_{j:(j,m)\in M_J}g_{jt}\cdot(1-v_{jt}(z))+\Delta l_{mt}(z)=\\
&\sum_{i:(i,m)\in M_I}(y_{it}^{up}(z)-y_{it}^{dw}(z)+y_{it}^{su}(z))\\
&+l_{mt}^{sh}(z)+y_{mt}^{up}(z)-y_{mt}^{dw}(z)\\
&+\sum_{s:(m,s)\in\Lambda}\left(f_t(m,s)-f_t(m,s)(z)\right),\ \forall m,\forall t,\forall z.
\end{aligned}\tag{9}$$

Transmission Capacity:

$$\begin{aligned}
&-F^{max}(m,s)\le f_t(m,s)(z)\le F^{max}(m,s),\\
&\forall(m,s)\in\Lambda,\forall t,\forall z.
\end{aligned}\tag{10}$$

Consumption Limits:

$$\sum_{t=1}^{T}d_{mt}(z)\cdot\varphi_t\ge E_m^{hour},\ \forall m,\forall z.\tag{11}$$

Shedding Limits:

$$l_{mt}^{sh}(z)\le d_{mt}(z),\ \forall m,\forall t,\forall z.\tag{12}$$

This part of the formulation, which involves the actual operation of the system (second-stage constraints), also include minimum up/down time of dispatchable generators and ramping constraints of both generating units and flexible demands. For the sake of conciseness, the mathematical formulation of these constraints is omitted.

First- and Second-Stage Constraints Pertaining to the Hour-Ahead and Balancing Market Operation.

Power Decomposition:

The actual power output of dispatchable generator *i* during period *t* and under scenario *z* is defined as:

$$g_{it}(z) = g_{it} + y_{it}^{up}(z) - y_{it}^{dw}(z) + y_{it}^{su}(z),\ \forall i, \forall t, \forall z. \quad (13)$$

Moreover, the actual load for flexible demand at bus *m* in period *t* and scenario *z* is expressed as:

$$d_{mt}(z) = d_{mt} - y_{mt}^{up}(z) + y_{mt}^{dw}(z),\ \forall m, \forall t, \forall z. \quad (14)$$

Reserve Deployment Limits:

On the one hand, the reserve deployment of a dispatchable generator is conditioned by its reserve capacity. This can be written as:

Up/Down Reserve:

$$0 \le y_{it}^{up}(z) \le r_{it}^{up} \cdot v_{it}(z),\ \forall i, \forall t, \forall z \quad (15)$$

$$0 \le y_{it}^{dw}(z) \le r_{it}^{dw} \cdot v_{it}(z),\ \forall i, \forall t, \forall z. \quad (16)$$

Start-Up Reserve:

$$G_i^{min} \cdot u_{it}(z) \le y_{it}^{su}(z) \le r_{it}^{su},\ \forall i, \forall t, \forall z. \quad (17)$$

On the other hand, the maximum up/down reserve deployment of flexible demand at bus *m* in period *t* is described in the next constraints:

$$0 \le y_{mt}^{up}(z) \le r_{mt}^{up},\ \forall m, \forall t, \forall z \quad (18)$$

$$0 \le y_{mt}^{dw}(z) \le r_{mt}^{dw},\ \forall m, \forall t, \forall z. \quad (19)$$

The stochastic programming problem was solved using DICOPT, a mixed integer nonlinear programming solver under GAMS (Rosenthal, 2015).

Case Study

The market clearing model was analyzed on the three-phase microgrid ATENEA located at the installations of the National Renewable Energy Centre of Spain (CENER) in Sangüesa, Navarre, Spain. This microgrid is a low-voltage (400/230 V) installation that can operate interconnected or isolated from the distribution network. The main elements are (Aguado et al, 2012):

- Renewable generators: A photovoltaic generator (PV) of 25.2 kWp.
- Batteries: A vanadium flow battery (VFB) capable of delivering 50 kW during 4 hours, and a lead acid battery (LAB) capable of delivering 50 kW during 2 hours.
- Conventional generators: A diesel turbine (DT) of 55 kW and a gas microturbine (GT) of 30 kW.
- Loads: A three-phase bank of programmable resistive loads of 87.63 kW that allows emulating any load profile.

The microgrid ATENEA is shown in Figure 1, where the distribution system represents the generator 1, the GT the 2, the DT the 3, the LAB the 4, the VFB the 5, and the PV is the generator 6. The five distribution lines have identical impedance values. The resistance and reactance are all 0.0547 p.u. and 0.0283 p.u. respectively, on a base of 1 MW and 0.4 kV.

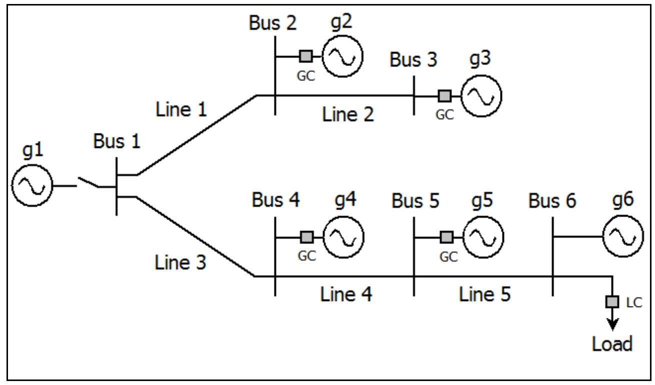

Figure 1. Microgrid ATENEA.
Source: The authors

The stochastic programming formulation analyzes the scheduling of this 6-buses microgrid over a horizon of four periods of 15 min, i.e., one hour.

The demand for the next scheduling horizon in 15-min periods is emulated using the three-phase bank of programmable resistive loads. The standard deviation of the load forecast error is assumed to be 5% of the 15-min load forecast. In addition, the loads are located at bus 6 and offer up to 10% of the demand at each period as reserve services (both up- and down-going) at the rate of 16 dollar cents per kilowatthour. It is also assumed that these loads value involuntary loss-of-load at the rate of 500 dollar cents per kilowatthour during all four periods.

The hourly irradiance forecasts are evaluated using mesoscale numerical weather prediction models operated and combined with statistical post-processing based on learning machines at CENER (Perez et al, 2013).

The stochastic behavior of net load forecast error throughout the next scheduling horizon is represented accurately by 625 possible scenarios. The size of this scenario set is too large, resulting in an optimization model that is intractable. Hence, to achieve tractability, statistical techniques (Heitsch & Römisch, 2003) are applied in order to reduce the number of scenarios while retaining the essential features of the original scenario set. The reduced scenario set obtained through this process includes 40 scenarios. Likewise, the stochastic behavior of the unit outages over the next scheduling horizon is modeled by 15625 possible scenarios. Because the size of this scenario set is too large, the number of scenarios is reduced by considering only single failures that represent the 99.99% of the unit outages probability distribution. The reduced scenario set includes 25 scenarios.

The generating unit data are found in Table 1. The fuel-consuming generators incur fixed start-up cost C_{it}^{SU} in dollar cents. Each generator offers a single block of energy ranging between its technical minimum G_i^{min} and maximum G_i^{max} at the bid composed by rate cost C_{it} in dollar cents per kilowatthour (fuel cost for fuel-consuming units and energy purchase cost for storage units) and fixed no load cost C_{it}^{NL} in dollar cents per hour (hourly payback amount for the investment). The generation-side reserve capacity services C_{it}^{R} for up-going reserve, for down-going reserve, and for start-up reserve are offered at rates in dollar cents per kilowatthour.

Table 1. Generating unit data

	Generator *i*			
	2	3	4	5
G_i^{max} (kW)	30	48	50	50
G_i^{min} (kW)	2	2	0	0
C_{it} (¢/kWh)	19.23	25	8.53	11.44
C_{it}^{NL} (¢/h)	120.17	33.78	138.27	492.68
C_{it}^{SU} (¢)	1.60	15.28	0	0
C_{it}^{R} (¢/kWh)	0.4	0.4	0.4	0.4
λ_i (faults/years)	6	6	6	6

Source: The authors

The failure rate λ_i of both the network and the PV is 6 faults/year. The hourly price of the energy supplied from the network to the microgrid C_{it}, for February of 2015, is defined in Table 2 in dollar cents per kilowatthour.

Table 2. Energy prices from IBERDROLA on February, 2015

Hour	C_{it} (¢/kWh)	Hour	C_{it} (¢/kWh)	Hour	C_{it} (¢/kWh)
0-7	6.37	10-12	11.07	18-20	11.07
8-7	9.39	13-17	9.39	21-23	9.39

Source: The authors

The distribution network and the batteries are considered special sources, because they can sell energy to or buy energy from the microgrid. The bid offer of the network C_{it} to buy energy from the microgrid is zero, because of the actual regulatory conditions of the microgrid ATENEA do not permit to remunerate the energy supplied to the network. Likewise, the bid offer of the batteries C_{it} to buy energy from the microgrid equals the bid offer of the network to sell energy to the microgrid, assuming that the batteries are only charged with energy supplied from the network.

Energy Management Procedure

Description.

In order to implement the market clearing model on the microgrid ATENEA, an iterative energy management methodology was developed using JAVA. The methodology is described below as a four-step procedure, where the first step is executed once a day, the second every 1 hour, the third every 15 minutes, and the fourth step every 10 milliseconds.

First-step: Daily at 06:00 am, the microgrid control client receives from the weather station server the hourly irradiance forecasts of Sangüesa, Navarre, Spain for the next 24 hours. These forecasts are stored in the file called "forecast".

At 06:00 am of each day, the demand of the microgrid is forecasted for the next 24 hours with a 15-min resolution. These forecasts are stored in the "forecast" file.

The irradiance forecasts have an hourly resolution, therefore the same forecast for the four 15-min periods of the next scheduling horizon is considered. The forecasts for the next scheduling horizon are stored in a file called "input" containing the input parameters of the market clearing model developed in GAMS.

Second-step: 5 minutes before starting the next scheduling horizon, the state of charge of batteries (LAB and VFB), the power generated by fuel-consuming units (GT and DT), and the demand consumed by loads are read from the SCADA. These parameters are sent to the client control and stored in the "input" file. Moreover, the hourly bid price of the energy supplied by the distribution network for the next scheduling horizon is identified, and stored in the "input" file.

The net load scenarios that can occur during the next scheduling horizon along with their associated probability of occurrence are identified from the PV availability, the irradiance forecast and the demand forecast for the next scheduling horizon. The unit outage scenarios that can occur during the next scheduling horizon along with their probability of occurrence are identified from the failure rate of the units and the generators availability. These scenarios and probabilities are stored in the "input" file.

After completing the "input" file, the stochastic programming problem developed in GAMS for the next scheduling horizon is executed. This program generates the "output" file containing the first-state variables, evaluated before the revelation of scenarios, and the second-state variables, obtained after the revelation of the scenarios considered throughout the next scheduling horizon.

Third-step: At the beginning of the first period (at minute 0) of the scheduling horizon, the power generated by PV, the demand consumed by loads, and the units status (fault/safe) are read from the SCADA. These parameters describe the actual operation of the microgrid.

The scenario z that represents the actual condition of the microgrid is identified, from the pre-selected scenarios of net load and units status. Then, the optimal operations of both dispatchable units $(g_{it}(z))$ and loads $(d_{mt}(z))$ for the scenario previously identified are selected from the "output" file. The optimal operations of elements are stored in the file "setpoint", and sent as setpoints to the SCADA for their immediate execution by elements of the microgrid.

The same procedure developed for the first period (at minute 0), is performed for the second (at minute 15), the third (at minute 30) and for the fourth period (at minute 45) of the scheduling horizon.

The operation described in the third-step represents the secondary regulation of the microgrid. The response time of this regulation is up to 15 min after the occurrence of the stochastic event.

Fourth-step: Every 10 milliseconds the SCADA monitors and controls the power supplied by each of the units and the power demanded by loads, in order to ensure the continuous balance between production and consumption in the microgrid. The actions that ensure the power balance every 10 ms are performed by a unit of the microgrid called "master". The LAB is the "master" in the isolated condition of the microgrid, and the distribution network in the connected condition.

The operation explained in the fourth-step represents the primary regulation of the microgrid.

Furthermore, the SCADA monitors every 10 ms the operational configuration of the microgrid (interconnected/islanded), in order to reassign the ``master" if there is a change in the configuration.

SICEL VIII Simposio Internacional sobre Calidad de la Energía Eléctrica 2015
Noviembre 18, 19 y 20 Valparaíso Chile

Results and Analysis.

The energy management methodology was evaluated throughout seven consecutive scheduling horizons, i.e., seven hours. The operational configuration of the microgrid ATENEA considers this grid interconnected to the distribution network limiting the capacity of the network to 15 kW.

The load forecasts d_{mt} and the irradiance forecasts h_t over the seven scheduling horizons in 15-min periods are given in Table 3.

Table 3. Load forecast (kW) and irradiance forecast (W/m²)

Hour	d_{m1}	d_{m2}	d_{m3}	d_{m4}	h_1	h_2	h_3	h_4
10	35.0	43.5	47.5	45.0	292.2	292.2	292.2	292.2
11	50.0	54.0	52.5	44.0	455.7	455.7	455.7	455.7
12	25.0	29.0	19.0	17.0	570.7	570.7	570.7	570.7
13	5.0	3.5	6.5	6.0	628.2	628.2	628.2	628.2
14	7.5	5.0	11.0	15.0	624.8	624.8	624.8	624.8
15	35.0	40.0	43.0	37.5	561.0	561.0	561.0	561.0
16	30.0	34.0	32.5	26.0	440.9	440.9	440.9	440.9

Source: The authors

Table 4 provides a breakdown of the expected cost of the microgrid, in dollar cents, into the cost pertaining to the energy supply, the cost of hiring reserve capacity, the expected cost of the balancing actions to be taken during the real-time operation, and the expected cost of the load shedding. This table shows that the market clearing solutions during the fourth and fifth scheduling horizons (hours 13 and 14) exhibit economic benefits for the microgrid, since the PV energy output is higher that the demand throughout these time periods, and therefore, the LAB is charged.

Table 4. Breakdown of expected cost (¢)

Hour	Energy	Reserve capacity	Reserve Deployment	ELNS	TOTAL
10	606.63	6.03	13.85	5.24	631.75
11	671.22	6.95	8.65	5.35	692.17
12	122.04	5.57	-0.45	1.45	128.62
13	-99.34	12.84	8.86	0.12	-77.52
14	-57.46	10.01	2.46	0.52	-44.48
15	401.59	6.19	21.40	5.18	434.36
16	303.20	5.88	18.59	2.15	329.82
TOTAL	1947.88	53.47	73.36	20.01	2094.72

Source: The authors

The reserve capacity cost is comparatively significant mainly due to the uncertainty in the PV power forecast. In this sense, it should be taken into account that, on the one hand, PV constitutes an important source of cheap renewable energy but, on the other hand, reserves are required in order to accommodate its unpredictable variability and, thus, to maintain the security and reliability of the system.

The results presented below describe and analyze the energy management in the microgrid for the second scheduling horizon (hour 11). The remaining horizons have the same treatment.

Table 5 summarizes the key features of the optimal schedule obtained for the second horizon. This table outlines the optimal generation and reserve schedules of the dispatchable units as well as the demand reserve contributions. Generator 1, being the cheapest, supplies its maximum power capacity during all the four periods and therefore does not provide any reserve. Generators 4 and 2, being the next cheapest units, pick up the residual demand and provide up and down reserves during the periods 1 to 3 and 4, respectively. In addition, generators 3 and 5 are never turned on. The PV provides a negative demand during the four periods, depending on the irradiance forecasts. The load at bus 6 provides up and down voluntary reserves, and furthermore, as seen in the last row of Table 5, the optimum market clearing schedule calls for some involuntary load shedding during all the four periods. This table also shows that due to the high value of lost load (500¢/kWh), the ELNS at bus 6 over the scheduling horizon is relatively low.

What makes this last result particularly interesting is that in spite of its high cost, the market clearing solution still calls for some amount of load shedding. This result is unique to the stochastic market clearing approach, reflecting the fact that some scenarios have both a low probability and a low impact in light of the relative expected costs of reserve deployment and load shedding. This brings out the essence of the probabilistic security, which considers simultaneously the credibility and severity of the scenarios making up the security criteria.

Table 5. Power (kW), reserve capacity (kW), and ELNS (kWh)

	Hour 11			
	1	2	3	4
g_{1t}	15	15	15	15
r_{1t}^{up}	0	0	0	0
r_{1t}^{dw}	0	0	0	0
r_{1t}^{su}	0	0	0	0
g_{2t}	0	0	0	17.52
r_{2t}^{up}	0	0	0	9.97
r_{2t}^{dw}	0	0	0	5.57
r_{2t}^{su}	0	0	0	0
g_{3t}	0	0	0	0
r_{3t}^{up}	0	0	0	0
r_{3t}^{dw}	0	0	0	0
r_{3t}^{su}	0	0	0	0
g_{4t}	23.52	27.52	26.02	0
r_{4t}^{up}	4.99	4.58	5.09	0
r_{4t}^{dw}	1.29	1.37	1.34	0
r_{4t}^{su}	0	0	0	0
g_{5t}	0	0	0	0
r_{5t}^{up}	0	0	0	0
r_{5t}^{dw}	0	0	0	0
r_{5t}^{su}	0	0	0	0
g_{1t}^{PV}	11.48	11.48	11.48	11.48
d_{1t}	50.00	54.00	52.50	44.00
r_{1t}^{up}	4.61	5.40	5.25	4.40
r_{1t}^{dw}	5.00	5.40	5.25	0
$ELNS_{1t}$	1.24×10^{-3}	2.69×10^{-3}	3.80×10^{-3}	2.96×10^{-3}

Source: The authors

At the beginning of the each period for the second scheduling horizon, the power generated by PV, the demand consumed by loads, and the units status were read from the SCADA. Next, it is analyzed in detail how reserve is deployed and how load is shed during each time period of the scheduling horizon, because of the actual condition of the microgrid.

On the one hand, the SCADA reported that all the generators included in the market clearing are in safe condition for each of the four periods, therefore, the actual units status is represented by the pre-selected unit outage scenario *y=1*. On the other hand, the SCADA reports let to analyze that the net load forecast errors for the first, second, third and fourth periods are -0.99 kW, 4.31 kW, -1.14 kW and -0.63 kW, respectively. Thus, the actual operation is represented by the pre-selected net load scenario *x=4*. The power balancing actions required to counteract the scenarios *y=1* and *x=4* for each of the periods are presented in the Table 6.

Table 6. Reserve deployed (kW), and load shed (kW)

	Hour 11			
	1	2	3	4
y_{1t}^{up}	0	0	0	0
y_{1t}^{dw}	0	0	0	0
y_{1t}^{su}	0	0	0	0
y_{2t}^{up}	0	0	0	0
y_{2t}^{dw}	0	0	0	5.03
y_{2t}^{su}	0	0	0	0
y_{3t}^{up}	0	0	0	0
y_{3t}^{dw}	0	0	0	0
y_{3t}^{su}	0	0	0	0
y_{4t}^{up}	4.01	4.58	4.11	0
y_{4t}^{dw}	0	0	0	0
y_{4t}^{su}	0	0	0	0
y_{5t}^{up}	0	0	0	0
y_{5t}^{dw}	0	0	0	0
y_{5t}^{su}	0	0	0	0
l_{1t}^{sh}	0	0	0	0
y_{1t}^{up}	0	0	0	4.40
y_{1t}^{dw}	5.00	0.27	5.25	0

Source: The authors

The optimal operations of units and loads in period *t* and aggregated scenario *z* for the second scheduling horizon are sent as setpoints to the SCADA for their immediate execution by elements of the microgrid.

Stochastic Versus Deterministic Market Clearing Models.

The objective function of the deterministic security-constrained market clearing problem only includes those terms in equation (2) representing the costs pertaining to the energy-reserve dispatch [from line 1 to line 4]. Furthermore, this function is subject to the first-stage constraints pertaining to the hour-ahead market, and a fixed amount of reserve capacity is scheduled by including reserve constraints in the optimization procedure (Luna et al, 2015).

The deterministic market clearing model specifies the upward reserve capacity as the PV power forecast, and the downward reserve is represented as half this power for each period of the scheduling horizon. This is, because the reserve capacity optimized by the stochastic programming problem on the microgrid ATENEA mainly varies with the PV power output, however, this solution does not necessarily hold in other systems.

It is of interest to compare the results obtained with the stochastic approach to those of a purely deterministic security-constrained schedule. The deterministic and stochastic total costs cannot be readily compared because they are obtained through completely different objective functions. Nonetheless, Table 7 lets to make a comparison of energy and reserve capacity costs between the two models throughout the seven scheduling horizons.

Table 7. Breakdown of cost (¢)–Stochastic versus Deterministic

Hour	Stochastic		Deterministic	
	Energy	Reserve capacity	Energy	Reserve capacity
10	606.63	6.03	606.63	4.42
11	671.22	6.95	671.22	6.89
12	122.04	5.57	138.93	8.63
13	-99.34	12.84	-99.34	9.50
14	-57.46	10.01	-57.46	9.45
15	401.59	6.19	401.59	8.48
16	303.20	5.88	303.20	6.67
TOTAL	1947.88	53.47	1964.77	54.03

Source: The authors

This comparison permits to demonstrate that the energy and the reserve capacity costs of the stochastic schedule are lower than those associated with the deterministic schedule. The efficiency gain of the stochastic programming solution versus that of the deterministic solution equals 16.89¢ + 0.56¢ = 17.45¢. This result illustrates that when one considers the probability of stochastic scenarios affecting the microgrid and their impact on system operation costs, it is possible to pre-position the microgrid more economically, while still achieving a high level of security on the average.

Figure 2 compares the reserve capacity obtained from the stochastic and the deterministic market clearing model throughout the seven scheduling horizons.

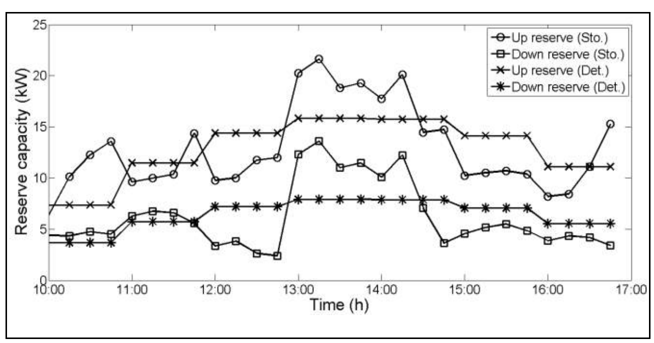

Figure 2. Comparison of reserve capacity–Deterministic versus Stochastic.
Source: The authors

This figure shows that the up and down reserves scheduled by the deterministic model are insufficient during some periods with respect to the reserves optimized by the stochastic problem. Whereas, during others, they exceed what is economically justifiable.

Conclusions

This paper proposes a market clearing model for microgrids adopting a probabilistic approach to estimate the reserve capacity needs. This model is a flexible and novel formulation that co-optimizes the hour-ahead and the balancing markets, in order to manage optimally the operation of grids with high levels of uncertainty.

An energy management methodology was developed for implementing the stochastic programming problem on the real microgrid ATENEA, located at the installations of CENER. The expected costs, the energy-reserve scheduling and the balancing actions to maintain the microgrid security were optimized and evaluated for seven consecutive scheduling horizons. These results have underlined that the stochastic methods should be considered in the operation planning of microgrids, since they offer many advantages and there are no major technical impediments in their implementation.

The scheduling results of the proposed stochastic formulation were compared with those obtained with a purely deterministic formulation. The preventive security control solution was found to be sub-optimal in the deterministic market clearing model, because this case does not consider neither the stochastic nature of a microgrid operation nor its economics. These studies have highlighted the potential economic benefits of a stochastic market clearing model.

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