Applied Energy 189 (2017) 403–415

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

Economic assessment of smart grid initiatives for island power systems

L. Sigrist [a,*], E. Lobato [a], L. Rouco [a], M. Gazzino [b], M. Cantu [b]

[a] Universidad Pontificia Comillas, Madrid, Spain
[b] Enel Ingegneria e Innovazione S.p.A., Pisa, Italy

HIGHLIGHTS

- RES, ESS, DSM and EV initiatives for island power systems are economically assessed.
- Five representative prototype island power systems have been considered.
- Islands of different sizes and features require different initiatives.
- Multi-action initiatives mainly reduce system operation costs.
- Single-action initiatives mainly achieve best IRR.

ARTICLE INFO

Article history:
Received 3 October 2016
Received in revised form 22 November 2016
Accepted 14 December 2016

Keywords:
Smart island
Unit commitment
Energy storage
Renewable energy sources
Demand side management
Electric vehicles

ABSTRACT

Islands are facing considerable challenges in meeting their energy needs in a sustainable, affordable and reliable way. The present paper develops an integrated approach to economically assess initiatives that can transform island power systems into smart ones. Single and multi-action initiatives fostering the deployment of renewable energy sources (RES), energy storage systems (ESS), demand-side management (DSM), and electric vehicle (EV) are considered. An hourly unit commitment on a weekly basis is proposed to assess the impact of the initiatives on the system operation costs of five prototype island power systems, which have been identified by applying clustering techniques to a set of sixty islands power systems. The different investment costs of the initiatives are accounted for determining their corresponding internal rate of return (IRR) through their lifetime. The economic assessment of single and multi-action initiatives for five prototype islands representing sixty island power systems quantifies which initiatives are most suitable for which type of island power system. The assessment shows that islands of different sizes and features require different initiatives. Larger islands tend to DSM initiatives, whereas smaller islands tend to RES initiatives. Multi-action initiatives achieve highest system operation cost reduction, whereas single action initiatives yield to highest IRR.

1. Introduction

Islands are facing considerable challenges in meeting their energy needs in a sustainable, affordable and reliable way. This is mainly due to the isolated nature and the small size of island power systems [1]. The geographic isolation also causes relatively high operation costs in comparison to large interconnected systems. Operation costs are not only higher because of expensive fuel transportation and lower efficiencies of the power generation technologies (e.g., Diesel), but also because of technical requirements on spinning reserves for guaranteeing frequency stability. Spinning reserve of island power systems usually covers the loss of the largest generating unit [2–5]. Actually, island power systems are more sensitive to frequency instability than larger interconnected systems since they exhibit a smaller inertia and each generating unit represents a significant fraction of the total generation infeed [6].

According to local resource availability, renewable energy sources (RES) offer an interesting solution to decrease the dependency on fossil fuels and increase island sustainability [7]. Since the intermittent behavior of RES can however affect the stability of island power systems, energy storage systems (ESS), electric vehicles (EV) offering a vehicle-to-grid operation, and demand-side management (DSM) have been introduced to mitigate the impact of the intermittent behavior of RES. In order to increase island sustainability, a combination of several actions needs therefore to be carried out, customized on specific islands, opportunities and constraints [8]. These actions that increase the flexibility of the system are allocated on the supply-side and the demand-side of

* Corresponding author.
E-mail address: lukas.sigrist@iit.comillas.edu (L. Sigrist).

http://dx.doi.org/10.1016/j.apenergy.2016.12.076
0306-2619/

Nomenclature

Sets

g	thermal unit
ess	energy storage system unit
h	hour
D	day
T	daily EV charging/discharging time window

Parameters

C_g^{fix}	the fixed cost of unit g [€]
C_g^{lin}	linear component of the variable cost of unit g [€/MW]
C_g^{qua}	quadratic component of the variable cost of unit g [€/MW^2]
$C_g^{start\text{-}up}$	start-up cost of generator g [€]
$C_g^{shut\text{-}down}$	shut-down cost of unit g [€]
$C^{rescurt}$	cost of RES curtailment [€/MW]
$P_g^{\min}$	minimum power generation of unit g [MW]
$P_g^{\max}$	maximum power generation of unit g [MW]
R_g^{up}	ramp-up of unit g [MW/h]
R_g^{down}	ramp-down of unit g [MW/h]
D_h	total power demand in hour h [MW]
$Pres_h$	wind and PV power production in hour h [MW]
$P_{ess,char}^{\max}$	maximum charging power of unit ess [MW]
$P_{ess,disch}^{\max}$	maximum discharging power of unit ess [MW]
$E_{ess}^{\min}$	minimum energy storage capacity of unit ess [MW h]
$E_{ess}^{\max}$	maximum energy storage capacity of unit ess [MW h]
η_{ess}^{char}	charging efficiency of unit ess
η_{ess}^{disch}	discharging efficiency of unit ess
$Ddisp^{max}$	maximum dispatchable power demand [MW]
$Ddisp^{min}$	minimum dispatchable power demand [MW]
$Ddispd_D^{\max}$	maximum dispatchable energy demand [MW h]
$Ddispd_D^{\min}$	minimum dispatchable energy demand [MW h]
$\delta Ddisp_h$	allocation of dispatchable demand $Ddisp$ in hour h
Dev^{max}	maximum charging/discharging EV power [MW]
$E_{eV}^{\min}$	minimum energy storage capacity of EVs, [MW h]
$E_{eV}^{\max}$	maximum energy storage capacity of EVs [MW h]
$Devd_D^{\max}$	maximum daily EV energy level [MW h]
$Devd_D^{\min}$	minimum daily EV energy level [MW h]
η_{eV}^{up}	charging efficiency of EV
η_{eV}^{down}	discharging efficiency of EV
δDev_h	allocation of EV charging/discharging in hour h

Binary decision variables

$\delta_{g,h}$	state of unit g in hour h
$\delta_{ess,disch,h}$	state of discharging of ess in hour h
$cx_{g,h}$	start-up decision of unit g in hour
$dx_{g,h}$	shut-down decision of unit g in hour h

Continuous decision variables

$p_{g,h}$	is the power generation of unit g in hour h [MW]
$prescurt_h$	curtailed RES generation in hour h [MW]
$resso_h^{up}$	system operator ramp-up spinning reserves required in hour h [MW]
$resso_h^{down}$	system operator ramp-down spinning reserves required in hour h [MW]
$resgen_h^{up}$	ramp-up spinning reserves provided by thermal generating units in hour h [MW]
$resgen_h^{down}$	ramp-down spinning reserves provided by thermal generating units in hour h [MW]
$resess_h^{up}$	effective ramp-up spinning reserves used from the energy storage systems in hour h [MW]
$resess_h^{down}$	effective ramp-down spinning reserves used from the energy storage systems in hour h [MW]
$pchar_{ess,h}$	charging power of unit ess in hour h [MW]
$pdisch_{ess,h}$	discharging power of unit ess in hour h [MW]
$e_{ess,h}$	is the actual energy storage capacity of unit ess in hour h [MW h]
$ddisp_h^{up}$	upward variation of the dispatchable component of the power demand in hour h
$ddisp_h^{down}$	downward variation of the dispatchable component of the power demand in hour h
dev_h^{up}	charging of EV in hour h
dev_h^{down}	discharging of EV in hour h
$resev_h^{up}$	effective ramp-up spinning reserves used from the EVs in hour h [MW]
$resev_h^{down}$	effective ramp-down spinning reserves used from the EVs in hour h [MW]
eev_h	is the actual energy storage capacity of unit ess in hour h [MW h]

the energy system [9,10]. Actions can be basically separated into three categories: (i) generation-side: use of natural gas and/or RES for power generation and use of ESS for reserve provision, (ii) grid-side: interconnection of island systems with other island systems or the continental system, and (iii) demand-side: use of ESS, implementation of DSM and promotion of EV. The use of natural gas instead of oil for power generation is however affected by the availability of local resources and/or the existence of economies of scale in both gas pipe lines and liquefied natural gas. Similarly, interconnection of an island system to the continent can be prevented by presence of deep waters and the existence of economies of scale (both in case of AC and HVDC transmission). Whereas past studies primarily focused on the optimal deployment of a single action, Ref. [11] has studied the impact of five different actions (DSM, use of natural gas, RES curtailment, ESS, and interconnectors) by combining some of them to improve RES integration and reduce system costs in the Western European system for 2050. ESS and interconnector options seem to be valuable for RES penetration above 60% of annual power generation.

The main objective of the present paper is to develop an integrated global approach to economically assess the main initiatives to be carried out over time that can transform island power systems into smart ones. This quantitative assessment is well suited to provide guidance on which initiatives are most suitable [11]. An initiative is understood as either a single action or a set of multiple actions. Different penetration levels of each action are considered. Since the shift from oil to gas and interconnection of islands to a continent can depend on local factors and on economies of scale, RES (particularly wind and PV generation), ESS, DSM, and EV actions are further investigated. Further, the multi-task capability of ESSs needs to considered as well. ESSs provide here both spinning reserve and load shifting services. Thus not only one type of action with different penetration levels but also multiple simultaneous actions and their impact on various islands of different features are economically assessed for the first time. The assessment consists of determining firstly the impact of single-action and multi-action initiatives on the system operation costs of an island power system. Furthermore, the different investment costs of the initiatives are accounted as well for determining their corresponding IRR through their lifetime. Past studies primarily focused on system cost savings or associated RES spillage reduction [11–16]. Since investment costs of DSM and EV are difficult to estimate, initiatives are assessed for different investment costs of DSM and EV actions.

As most island systems are operated under a classical centralized scheme, hourly unit commitment on a weekly basis is proposed to assess the impact of the initiatives on the system operation costs of an island. A set of five representative prototype island power systems is used to take into account the difference among island power systems. These prototype islands, which have been identified by applying clustering techniques to a set of nearly 60 islands, are described by the economic and technical features of real island power systems closest to the cluster. The idea of grouping islands into clusters in terms of their climatic, geophysical, geographic and socio-economic parameters has also been proposed by [17] in order to identify similar islands concerning their implementation potential of RES. This paper groups islands as well but this time in function of the energy demand, the peak demand, the installed capacity, the highest transmission and distribution (T&D) voltage level, the population, the average system operation cost, and the gross domestic product (GDP) in order to find the most appropriate initiatives in terms of system operation costs and IRR. The economic assessment of single and multi-action initiatives for five representative prototype island power systems allows therefore quantifying which initiatives are most suitable for which type of island power system. In other words and as a starting point, appropriate initiatives can be immediately listed for a given island, associated to one of the prototype islands.

The paper is organized as follows: Section 3 reviews currently implemented actions towards smarter islands; Section 4 proposes the methodology to assess initiatives based on a financial analysis of prototype islands; Section 5 presents the results and section 6 concludes the paper.

2. Review of current actions towards smarter islands

The high cost of electricity supply in island power systems may turn viable initiatives that are not viable in large systems. In [8], six types of actions have been identified: Oil to gas, flexible generation, interconnectors, RES, ESS, and DSM. In the technical literature, attention has been mainly paid to RES, ESS, and DSM actions. Ref. [18] presents a methodology to quantify the potential of wind energy production and its location in the islands of Tenerife, Fuerteventura and La Gomera. Viability of hybrid wind–PV systems in Cape Verde have been studied in [19] by assessing the available wind resource in particular in order to exploit the highest wind potential areas. Small off-the grid systems supplying power to nearby single consumers such as schools or kiosks are usually based on PV systems [20]. Further and as shown in [21], cost and fuel synergies across electricity, heating, and transport can be exploited to increase the potential for fluctuating RES. Ref. [12] has shown for a 100% RES system in South East Europe for 2050 that wind and PV power generation will be the dominant technology and that biomass, mainly used in cogeneration units, is only sustainable if there is need for some type of synthetic fuel in the transportation sector. Dispatchable hydro and biofuel plants are required for a low-carbon electricity supply in Australia to plug gaps caused by occasional low-resource periods [22]. In [23,24], tri-generation systems for the islands of Pulau Ubin and Pantelleria have been designed with both systems being viable for certain RES operation schemes (e.g., reducing peak loads or covering 20% of the demand by RES) and demand conditions (e.g., domestic hot water demand significantly improves the Pantelleria's profitability including geothermal energy).

However, the intermittent behavior of RES can also affect the stability of island power systems if suitable constraints are not imposed to system operation [25,26]. Energy storage systems (ESS) and electric vehicles (EV) offering a vehicle-to-grid operation can mitigate the impact of the intermittent behavior of RES [13,27,28]. Ref. [15] discusses the simultaneous provision of spinning reserve and peak shaving services by ESS for the islands of La Gomera and Gran Canaria and it shows that ESSs are a viable option. EVs have also shown to be effective for power balancing services in Denmark under high wind generation, reducing power exchange deviations remarkably [15]. ESS operating on diurnal and seasonal scales (via flow batteries and hydrogen electrolysis) and a shift in the capacity mix of dispatchable generation from baseload towards more peaking power plants improve variable RES integration [29]. Appropriate demand-side management (DSM) can also improve RES penetration and reduce fossil fuel consumption [30]. In [16], an assessment of the impact of DSM on the economic operation of the island of Gran Canaria with high wind generation has been presented, concluding that DSM thanks to its flexibility is able to reduce wind spillage.

Finally, a literature review on past and on-going projects on the aforementioned six actions, their main actors and the projects' stage has been carried out. Oil to gas and flexible generation have been addressed in [31–33], whereas Refs. [34–36] present projects on interconnectors between Balearic Islands and Spain and Malta and Sicily. RES actions have been presented in [37–41]. Storage actions have been reported in [42–51], whereas references [48–50,52,53] address DSM actions. Although most projects focus on one action, there are some projects that included several actions simultaneously [38,54–62]. Typically, RES actions have been combined with ESS actions and to a lesser extent with DSM actions.

Fig. 1 shows the reported actions in terms of their type, their main actors and their stage according to the data collected form [31–63]. It can be deduced from Fig. 1(a) that most actions deal with RES and/or ESS, whereas DSM, oil to gas, flexible generation and interconnectors are less widely analyzed and implemented. ESS actions are usually driven by generator-side actors in order to improve compliance with security constraints. However, ESS have shown to be viable as well for other services such as peak-shaving. RES actions are usually driven by generator- and/or network-side actors in order to reduce operation costs. It is worthwhile to note that most actions are actually generator-side driven as shown in Fig. 1(b). Actions including both RES and ESS focused on reduction of operation cost by guaranteeing security constraints simultaneously. Finally, Fig. 1(c) shows that most actions are in a project-stage or under operation. Some projects already show a certain degree of maturity and provide results, whereas only a few projects are at the stage of feasibility study.

To speed up an effective transition towards "smart islands" implementation, an integrated global approach is needed to determine the main initiatives to be carried out over time. It is essential that these initiatives are viable in terms of IRR.

3. Methodology to assess initiatives towards smarter and more sustainable island power systems

The section presents the methodology to assess initiatives towards smarter and more sustainable island power systems. First the prototype islands are determined. Since system operation and operation costs depend on island features, the diversity of island power systems is taken into account by analyzing prototype islands, identified by applying clustering techniques to set of real island power systems. A prototype island is described by the real island power system closest to a clusters' centroid. Second, the impact of the initiatives, consisting of single or a set of multiple

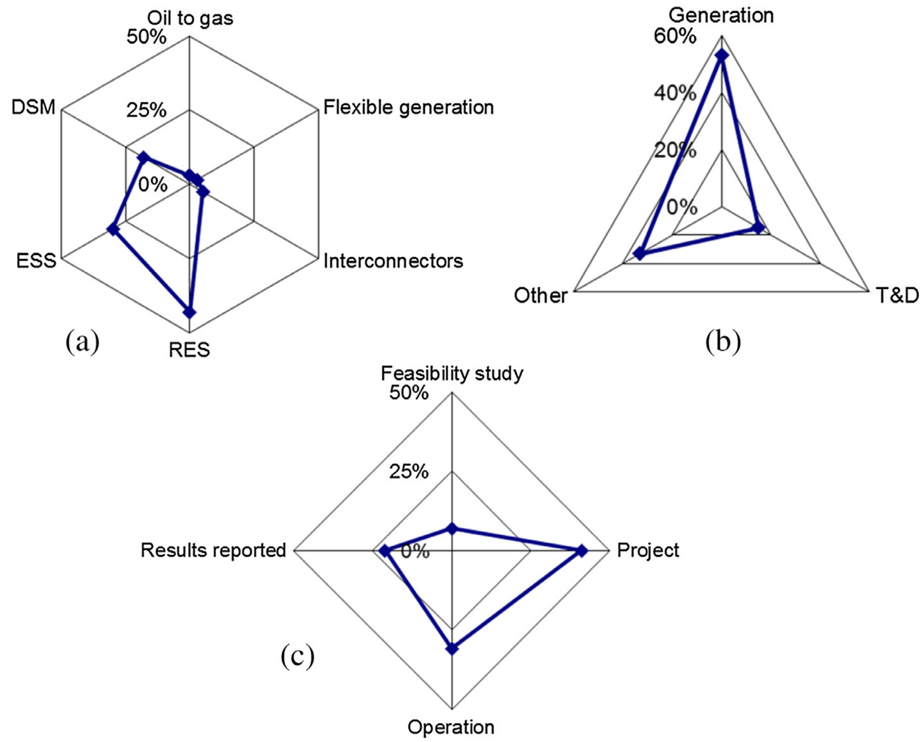

Fig. 1. Reported actions in terms: (a) action type, (b) main action actor, and (c) action stage.

actions, on the system operation cost reduction of each prototype island is evaluated. As most island systems are operated under a classical centralized scheme, an hourly weekly unit commitment is used, considering four representative weeks of the year to account for seasonal variability. Together with the investment cost, the system operation cost reduction allows computing the IRR of each initiative over its lifetime, which has been set to 15 years.

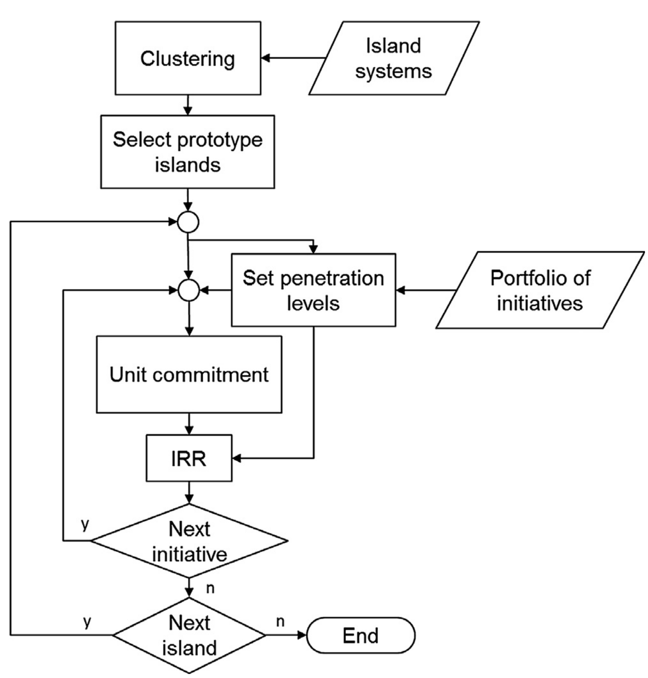

Fig. 2. Overview of the methodology to assess initiatives towards smarter and more sustainable island power systems.

The IRR indicates whether a particular initiatives is viable or not. Fig. 2 gives an overview of the methodology.

3.1. Prototype islands

The identification of prototype islands can be realized by means of several clustering techniques. Clustering refers to the partitioning of a data set into clusters, so that the data in each subset ideally share some common trait and differ from the data in other subsets. K-Means clustering algorithm is used here, although Fuzzy C-Means or KSOM algorithm could be used as well with similar results [6].

The K-Means algorithm [64] attempts to cluster N objects into K_N partitions. The main objective is to find K_N clusters such that the quadratic quantization error (QE) is minimal:

$$\min\ (QE) \tag{1}$$

with

$$QE = \sum_{c=1}^{K_N} QE_c = \sum_{c=1}^{K_N} \sum_{\substack{e \in Learning\ Set \\ e \in Cluster\ c}} \|\mathbf{x}_e - \mathbf{c}_c\|^2 \tag{2}$$

In general, the Euclidean distance is used as a distance measure between clusters and the input data vectors. The input vectors $\mathbf{x}_e$ belong to the learning set $\mathbf{\Omega}$ and describe the features of an island power system. Meaningful variables describing island power systems include the energy demand D_{Energy}, the peak demand D_{Peak}, the installed capacity P_{gen}, the highest T&D voltage level V_{TDmax}, the population n_{Pop}, the average system operation cost C_{Ave}, and the GDP. The input vector of the *jth* island is then expressed as:

$$\mathbf{x}_j = [D_{Energy} \quad D_{Peak} \quad P_{gen} \quad V_{TD\max} \quad n_{Pop} \quad C_{Ave} \quad GDP]$$

$\mathbf{c}_c$ is the centroid which is computed by averaging the $\mathbf{x}_e$ associated to the *cth* cluster. The real island power (the input vector $\mathbf{x}_j$) closest to the centroid $\mathbf{c}_c$ is then a prototype island. The number of clusters K_N is a priori unknown and needs to be estimated. Furthermore, K-Means strongly depends on the initial solution due to its inherent gradient-based optimization algorithm to solve QE. Nevertheless, K-Means is a fast algorithm.

3.2. Portfolio of initiatives

An initiative consists of a particular combination of wind, PV, ESS, DSM, and EV actions of different penetration levels, which in turn depend on the prototype island. For each action, five different penetration levels have been defined. Penetration levels and cost figures of wind, PV, ESS, DSM and EV actions are given Table 1. For instance, the wind generation profile for the current installed capacity is scaled up to an installed capacity corresponding to 25% of the average power demand. For ESS, a round-trip efficiency of 80% has been assumed and energy capacity has been set such that the ESS is able to operate at P_{in} during four hours. ESS are operated on a weekly basis, whereas EVs are operated on a daily basis, assuming an initial state of charge of 50% (a 30 kW h EV consuming 25 kW h/100 km for an average driving distance of around 60 km [65]). The ESS figures do not correspond to a particular ESS technology, but rather average figures of ESS for grid applications have been assumed since different ESS technologies can be used for the same purpose [66]. Costs not only depend on the ESS technology, but also on its maturity, its application and location, size of the system and other variables [67,68].

Note that penetration levels of all except EV actions are given in percentage of the average power demand, whereas penetration levels of EV actions are given in percentage of the estimated number of cars of an island. The installed power of EV can be expressed as follows:

$$P_{in,EV} = P_{EV} \cdot n_{cars} \cdot \%EV \tag{3}$$

where P_{EV} is the power demand of an EV (e.g., 3.3 kW), n_{cars} the number of cars and $\%EV$ the percentage of EV of n_{cars}. The cost parameter of EV actions corresponds to the cost of the charging point infrastructure, excluding the cost of the EV itself. For a slow charging point of 3.3 kW EV, the EV cost figure C_{EV} in €/kW/car can be computed as:

$$C_{EV} = \frac{C_{CP} \cdot n_{CP/EV}}{P_{EV}} \tag{4}$$

where C_{CP} is the cost of the charging point and $n_{CP/EV}$ the number of charging points per EV. It must be mentioned that the assumed EV investment cost discards other costs for utilities such as promotion costs, marketing costs, etc. [69]. In case of DSM programs, these costs might amount up to 10% of the total program costs [70].

3.3. Weekly unit commitment

As most island systems are operated under a classical centralized scheme, hourly unit commitment on a weekly basis is proposed to assess the impact of the initiatives on the system operation costs of a prototype island [14]. Demand profiles as well as wind and PV generation profiles are input variables, whereas start-up decisions of thermal units and hourly operation profiles of thermal generation units, ESS, DSM and EVs are outputs. Section 'Nomenclature' details the decision variables of the unit commitment problem. RES generation is commonly prioritized over conventional generation for generation dispatch in island power systems (e.g., [71]). High fuel costs further fosters RES generation. DSM and EVs are considered and modeled at an aggregated level. The unit commitment model is implemented in GAMS and solved with CPLEX.

Eq. (5) formulates the objective function of the unit commitment model, which aims at minimizing the total system operation cost C_{tot}, including the thermal generation costs, ESS and RES operation costs, DSM and EV transaction costs [16], and the penalization of a possible curtailment of wind and PV generation for system security reasons. For simplicity, wind and PV generation are represented by a single variable with attribute *res*, although they are both handled separately during the simulation.

$$\min(C_{tot}) \tag{5}$$

where

$$\begin{aligned} C_{tot} = \sum_{g,h}\Big[\Big(C_g^{fix} \cdot \delta_{g,h} + C_g^{lin} \cdot p_{g,h} + C_g^{qua} \cdot p_{g,h}^2 + C_g^{start-up} \cdot cx_{g,h} \\ + C_g^{shut-down} \cdot dx_{g,h}\Big)\Big] + \sum_{ess,h}(C^{ess} \cdot pchar_{ess,h}) \\ + \sum_h (C^{res} \cdot Pres_h + C^{rescurt} \cdot prescurt_h) \\ + \sum_h (C^{TrDSR} \cdot ddisp_h^{up} + C^{TrEV} \cdot dev_h^{up}) \end{aligned} \tag{6}$$

Penalization of wind and PV curtailment is such that security criteria for reserve are always met, i.e., it is preferable to curtail generation instead of violating reserve criteria. The weekly economic dispatch is constrained by the demand balance, by technical operation constraints of generators, ESS, DSM, and EVs, and by constraints with regard to the available amount of upward and downward reserve provided by generators and ESS.

Eq. (7) formulates the demand balance.

$$\begin{aligned} D_h = ddisp_h^{down} - ddisp_h^{up} + dev_h^{down} - dev_h^{up} + \sum_g p_{g,h} + Pres_h \\ - prescurt_h + \sum_{ess}(pdisch_{ess,h} - pchar_{ess,h}) \end{aligned} \tag{7}$$

Eqs. (8) and (9) describe the generation limits and the ramp constraints of thermal generators.

$$P_g^{min} \cdot \delta_{g,h} \leqslant p_{g,h} \leqslant P_g^{max} \cdot \delta_{g,h} \tag{8}$$

$$-R_g^{down} \leqslant p_{g,h+1} - p_g \leqslant R_g^{up} \tag{9}$$

Eqs. (10) and (11) compute the required upward and downward spinning reserves by summing reserves provided by generators, ESS, EV and wind and PV generation (only for downward reserve). Although spinning reserve is separated into primary and secondary reserves, primary frequency control uses part of the secondary reserve during generation-load imbalances. According to common operation procedures of island power systems, Eqs. (12) and (13) force the up reserve to be larger than the largest connected generator and larger than the expected losses of wind or PV generation. Note that the latter does not only include forecast errors but also probable losses of RES generation due to faults (e.g., short-circuits causing low voltage disconnection of wind farms or substation failures). In island power systems, where RES generation is

Table 1
Penetration levels and cost figures of contemplated actions.

	Installed power P_{in}	Energy capacity	Investment
Wind	(0–25–50–75–100)% average power demand	–	1000 €/kW [89]
PV	(0–25–50–75–100)% average power demand	–	2300 €/kW [89]
ESS	(0–2.5–5–7.5–10)% average power demand	4 h × P_{in}	2800 €/kW [67,68]
DSM	(0–1–2–3–4)% average power demand	(0–0.4–0.8–1.25–1.7)% of daily average energy demand	650 €/kW [70,90,91]
EV	(0–5–10–15–20)% number of cars	10 h × P_{in} (slow charging)	2400 € [92,93]

locally concentrated, the probable loss of RES generation is significant. Eq. (14) specifies that total down reserve must be larger than a certain fraction $k_{up2down}$ of the up reserve (typically 50%). Eqs. (15), (17) and (19) and Eqs. (16), (18) and (20) compute upward and downward reserves provided by thermal units, ESS and EVs, respectively.

$$resso_h^{up} = resgen_h^{up} + \sum_{ess} resess_{ess,h}^{up} + resev_h^{up} \tag{10}$$

$$resso_h^{down} = resgen_h^{down} + Pres_h - prescurt_h + \sum_{ess} resess_{ess,h}^{down} + resev_h^{down} \tag{11}$$

$$resso_h^{up} \geqslant p_{g,h}, \quad \forall g \tag{12}$$

$$resso_h^{up} \geqslant k_{ess2reserve}(Pres_h - prescurt_h) \tag{13}$$

$$resso_h^{down} \geqslant k_{up2down} resso_h^{up} \tag{14}$$

$$resgen_h^{up} = \sum_g (P_g^{max} \cdot \delta_{g,h} - p_{g,h}) \tag{15}$$

$$resgen_h^{down} = \sum_g (p_{g,h} - P_g^{min} \cdot \delta_{g,h}) \tag{16}$$

$$resess_{ess,h}^{up} = P_{ess,disch}^{max} - pdisch_{ess,h} + pchar_{ess,h} \tag{17}$$

$$resess_{ess,h}^{down} = pdisch_{ess,h} + P_{ess,char}^{max} - pchar_{ess,h} \tag{18}$$

$$resev_h^{up} = Dev^{max} - dev_h^{down} + dev_h^{up} \tag{19}$$

$$resev_h^{down} = dev_h^{down} + Dev^{max} - dev_h^{up} \tag{20}$$

Eqs. (21)–(24) impose the limits of discharging and charging power of ESSs as well as the associated energy dynamics and the energy capacity limits. Round-trip efficiency of ESS has been taken into account by means of a constant, although efficiency might vary according to the ESS operation.

$$0 \leqslant pdisch_{ess,h} \leqslant \delta_{ess,disch,h} \cdot P_{ess,disch}^{max} \tag{21}$$

$$0 \leqslant pchar_{ess,h} \leqslant (1 - \delta_{ess,disch,h}) P_{ess,char}^{max} \tag{22}$$

$$e_{ess,h} = e_{ess,h-1} + pchar_{ess,h} \cdot \eta_{ess}^{char} - pdisch_{ess,h} \cdot \eta_{ess}^{disch} \tag{23}$$

$$E_{ess}^{min} \leqslant e_{ess,h} \leqslant E_{ess}^{max} \tag{24}$$

DSM is modeled on an aggregated level. Eqs. (25) and (26) limit the hourly dispatchable DSM demands between minimum and maximum limits. These limits are set as a fraction of the energy demand. Further, the parameter $\delta Ddisp_h$ allows restricting DSM to certain hours, i.e., it defines availability slots. DSM variations must be balanced during one day and during their availability slots as shown in Eq. (27). Finally, the amount dispatchable demand is limited for a particular day (Eq. (28)).

$$Ddisp^{min} \cdot \delta Ddisp_h \leqslant ddisp_h^{up} \leqslant Ddisp^{max} \cdot \delta Ddisp_h \tag{25}$$

$$Ddisp^{min} \cdot \delta Ddisp_h \leqslant ddisp_h^{down} \leqslant Ddisp^{max} \cdot \delta Ddisp_h \tag{26}$$

$$\sum_{h \in D} ddisp_h^{down} = \sum_{h \in D} ddisp_h^{up} \tag{27}$$

$$Ddispd_D^{min} \leqslant \sum_{h \in D} ddisp_h^{up} \leqslant Ddispd_D^{max} \tag{28}$$

EVs are modeled as dispatchable demands on an aggregated level allocated in selected hours T of every day D. Eqs. (29) and (30) limit the hourly dispatchable EV demands between minimum and maximum limits. These limits depend on the number of available EV cars. Energy dynamics and energy capacity limits are formulated in Eqs. (31) and (32). Note that EV energy dynamics during driving are not modeled, but an average state of charge is assumed. Finally, Eq. (33) limits the energy available for EVs after the charging/discharging time window T of a day D.

$$0 \leqslant dev_h^{up} \leqslant Dev^{max} \cdot \delta Dev_h \tag{29}$$

$$0 \leqslant dev_h^{down} \leqslant Dev^{max} \cdot \delta Dev_h \tag{30}$$

$$eev_h = eev_{h-1} + dev_h^{up} \cdot \eta_{eV}^{up} - dev_h^{down} \cdot \eta_{eV}^{down}, \quad \forall h \in T \tag{31}$$

$$E_{eV}^{min} \leqslant eev_h \leqslant E_{eV}^{max} \tag{32}$$

$$Devd_D^{min} \leqslant \underset{h \in T}{eev_h} \leqslant Devd_D^{max} \tag{33}$$

Typically, unit commitment of an island power system is run for some representative weeks of a year to deduce the yearly system operation cost. For each representative demand scenario, all possible combinations of actions (i.e., Wind, PV, ESS, DSM and EV) are simulated. Each combination of actions constitutes an initiative, which needs to be economically assessed. Fig. 3 shows the action tree of a prototype island for a particular demand scenario.

3.4. Economic assessment of initiatives

Finally, each initiative is assessed in terms of both reduction of system operation costs and the internal rate of return. IRR depends on the investment parameters of each initiative and the cashflow, depending on the system operation cost reduction with respect to the current system operation cost. Since ESS or DSM actions shift load and reduce thus peak loads, they could defer capacity investments. However, capacity deferral has not been taken into account and IRR only contemplates system operation cost reduction as cashflow.

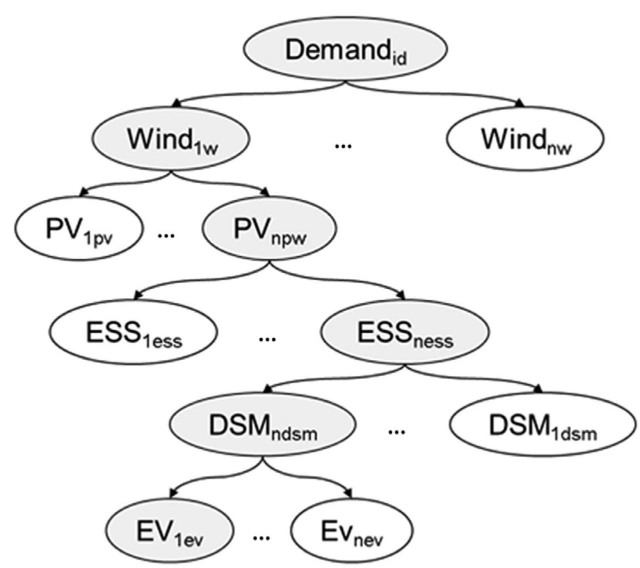

Fig. 3. Action tree of a prototype island and for a particular demand scenario *id*.

Eq. (34) defines the Net Present Value (NPV) [72,73]:

$$NPV = \sum_{t=0}^{n_{years}} \frac{C_t}{(1+r)^t} \quad (34)$$

where n_{years} is the expected lifetime, C_t the cashflow of year t and r the rate of return. An initiative is considered to be financially feasible only if the corresponding NPV is positive. The cashflow for $t > 0$ is given by the difference of the yearly system operation cost of the ith initiative $C_{tot,ini\ i}$ with respect to the current yearly system operation cost without initiatives $C_{tot,current}$:

$$C_t = C_{tot,ini\,i} - C_{tot,current} \quad (35)$$

The IRR is the rate of return for a zero NPV, i.e., IRR provides a lower feasibility bound. Eq. (34) can be rewritten in polynomial form as show in Eq. (36).

$$0 = \sum_{t=0}^{n_{years}} \frac{C_t}{(1+IRR)^t} = C_o + C_1 a_1 + \ldots + C_{n_{years}} a_{n_{years}} \quad (36)$$

The problem of finding the IRR is thus transformed into one of finding a real root p of that polynomial. Once the root has been found, the internal rate of return becomes:

$$IRR = \frac{1}{p} - 1 \quad (37)$$

An initiative is viable if the IRR is higher than a predefined acceptance limit, which is equal to or higher than the nominal annual discount rate [74].

4. Results

This section presents the results of applying the proposed methodology. For the purpose of identifying prototype islands, nearly 60 island power systems around the world have been identified. Wind, PV, ESS, DSM, and EV actions are evaluated for each prototype island. The weekly unit commitment is simulated for four representative weeks of the year, one per season.

4.1. Prototype islands

Fig. 4(a) shows the relation between the energy demand, the GDP and the population of the nearly 60 island power systems. Non-EU island system data have been taken from [75,76]. EU island system demand data have been taken from [8,77–88]. It can be seen that these features are quite correlated although some degree of dispersion exists. The larger the population, the larger is the GDP and the larger is the energy demand. Similarly, Fig. 4(b) shows the relation between energy demand, highest T&D voltage level and peak demand. The highest voltage level is determined by the distances between generation and load centres and the amount of power transmitted. Again, the three features seem to be correlated. This makes sense since the larger the peak demand, the more power needs to be transmitted, favouring higher transmission voltage levels.

Fig. 5 shows the results of applying the K-Means clustering algorithm. According to Fig. 5(a), which plots the QE in function of the number of clusters, five clusters (prototype islands) seem to be sufficient to describe the nearly 60 island power systems. Fig. 5(b) compares the five prototype and the nearly 60 island power systems by means of prinicpal component analysis (PCA). PCA is mathematically defined as an orthogonal linear transformation that transforms the data to a new coordinate system such that the greatest variance by any projection of the data comes to lie on the first coordinate (called the first principal component), the second greatest variance on the second coordinate, and so on [64]. It

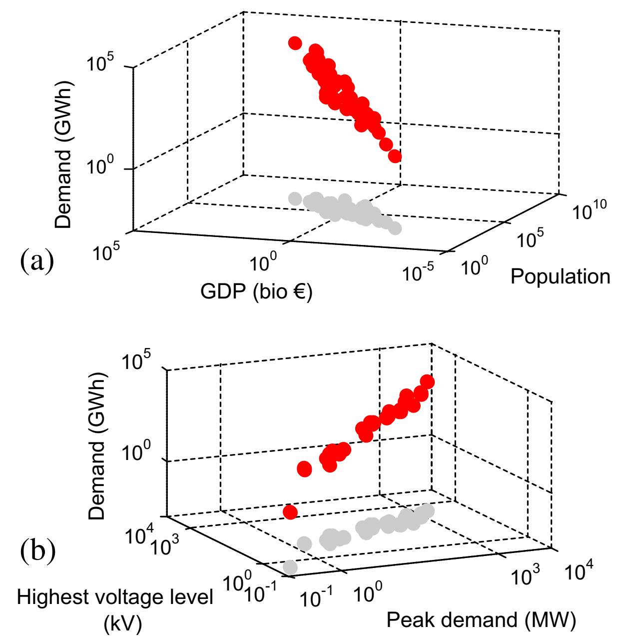

Fig. 4. Relation between different island features: (a) energy demand, GDP and population size, and (b) energy demand, peak demand, and highest T&D voltage level.

results that the five prototype islands satisfactorily represent the diversity of all island power systems.

Finally, Table 2 summarizes some of the features of the five prototype islands (i.e., real island power systems closest to the clusters' centroids) in terms of annual energy demand, installed generation capacity, highest T&D voltage level, average generation cost, and the population.

4.2. Economic assessment of initiatives

The impact of all possible single and multi-actions initiatives (totally 3125 initiatives) on the system operation cost of each of the five prototype islands has been simulated for the four representative seasonal demand scenarios.

Figs. 6 and 7 show the annual system operation cost reduction with respect to the current system operation cost in case of prototype island 2 (a larger island power system) and in case of prototype island 4 (a smaller island power system) for all considered single and multi-action initiatives. Zooms in Figs. 6 and 7 allow dissecting the impact of different actions. Arrows illustrate the direction of increasing sizes of actions. It can be inferred that the larger reductions of system operation costs are obtained when actions are implemented at higher penetration levels. This conclusion is also valid for prototype islands 1, 3 and 5 and it makes sense since the considered actions usually exhibit low variable costs in comparison to conventional power generation. Nonetheless, larger and smaller island as shown in Figs. 6 and 7 exhibit certain differences. Whereas the increase of wind and PV penetration levels always leads to an increase in annual cost reduction in case of a smaller island, wind and PV penetration levels of a larger system clearly show a maximum cost reduction. The penetration level of PV generation with maximum cost reduction increases with decreasing wind penetration level. Further, the influence of EVs is quite different. Whereas the cost reductions of prototype island 4 decrease with increasing EV penetration level (EVs are not an advisable option), the cost reductions of prototype island 2 show a different behavior: for lower EV penetration levels, annual costs go down, whereas for higher penetration levels, annual cost reduc-

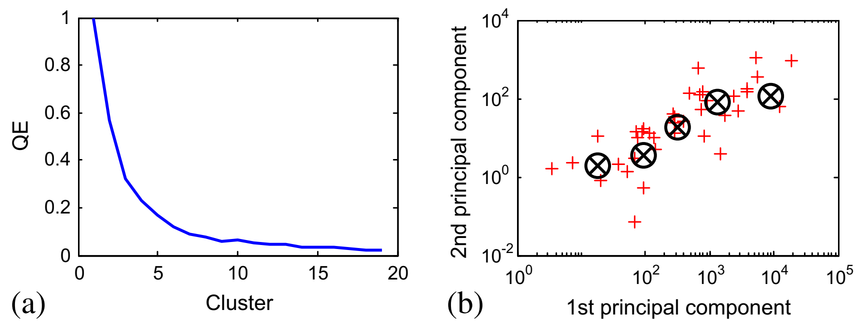

Fig. 5. (a) Quadratic quantization error in function of the number of clusters, and (b) principal component analysis of the clusters and the input data.

Table 2
Features of the five prototype island power systems.

Prototype	1	2	3	4	5
D_{Energy} (GW h)	10,627	1446.7	309.8	90.5	16.6
P_{gen} (MW)	2802.7	457.4	99.2	26.7	6.2
V_{TDmax} (kV)	220	66	66	32	32
n_{pop} (in thousands)	2550	244	88	33	5.5
C_{ave} (€/MW h)	81	118	101	146	140

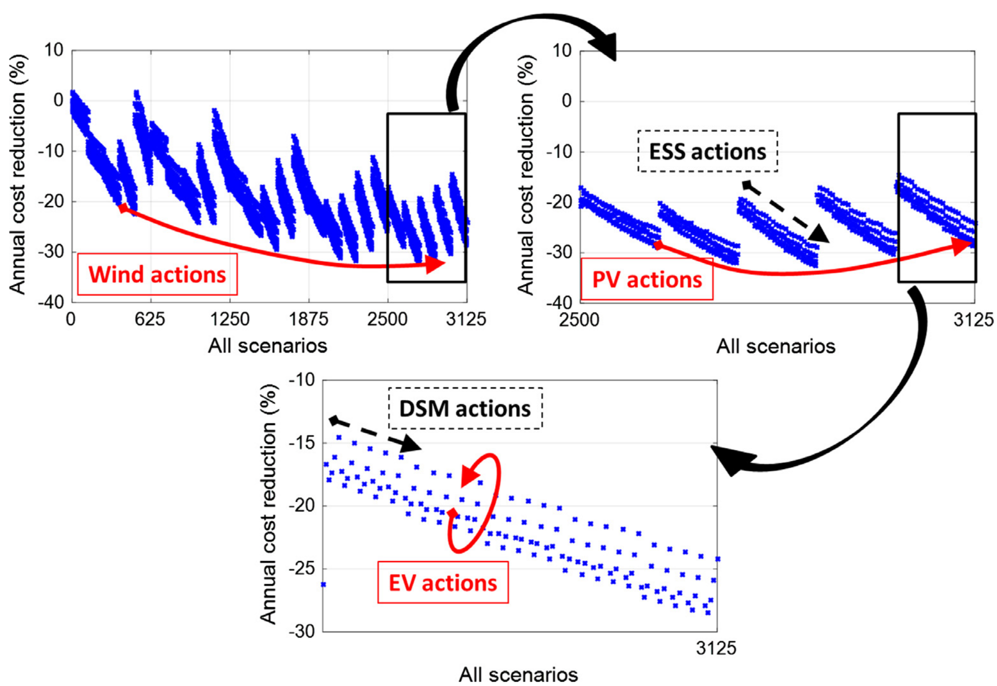

Fig. 6. Annual system cost reduction of prototype island 2 – aggregated impact of actions.

tions decrease. This can be clearly seen in the upper right graphic of Fig. 6, where positive cost reductions are found.

The impact of particular action also varies according to the prototype island. In case of a larger island system (see Fig. 6), wind and ESS actions have a higher influence on annual cost reduction (around €10 to €15 million) than PV, DSM, and EV actions (around €2 to €5 million). Both wind and PV actions have however a higher influence on annual cost reduction of a smaller island system (around €1.5 to €3 million) than ESS, DSM and EV actions. Particularly, ESS yield to less cost reduction for a smaller system than for a larger one.

The previous analysis of the impact of initiatives on annual system operation costs pinpoints that multi-actions initiatives are most effective. However, this analysis does not consider the investment cost required to implement the initiatives. Congruently, IRR of all possible single and multi-action initiatives is computed on the basis of the investment costs shown in Table 1.

Figs. 8 and 9 compare the five best initiatives in terms of annual cost reduction with the five best initiatives in terms of IRR for prototype island 2 and prototype island 4, respectively. In contrast to the results in terms of annual cost reduction, single actions or a few multiple actions implemented at their lower penetration levels succeed in terms of IRR since investment costs of the considered actions are usually high and higher than the investment costs of conventional generation. The IRR over 15 years pinpoints to the use of smaller DSM and/or EV actions for prototype island 2,

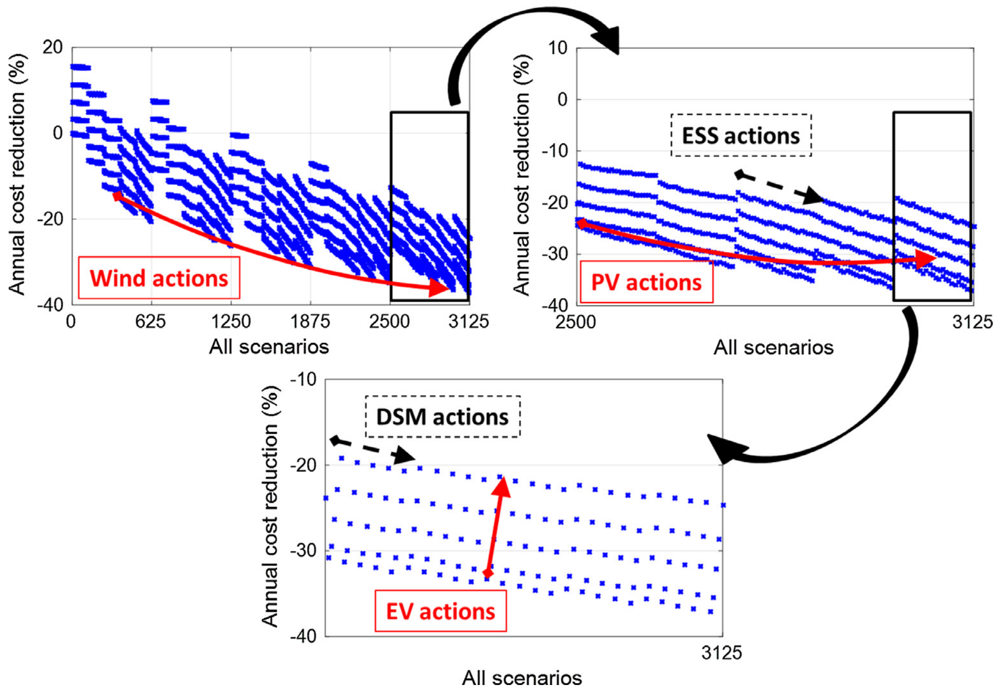

Fig. 7. Annual system operation cost reduction of prototype island 4 – aggregated impact of actions.

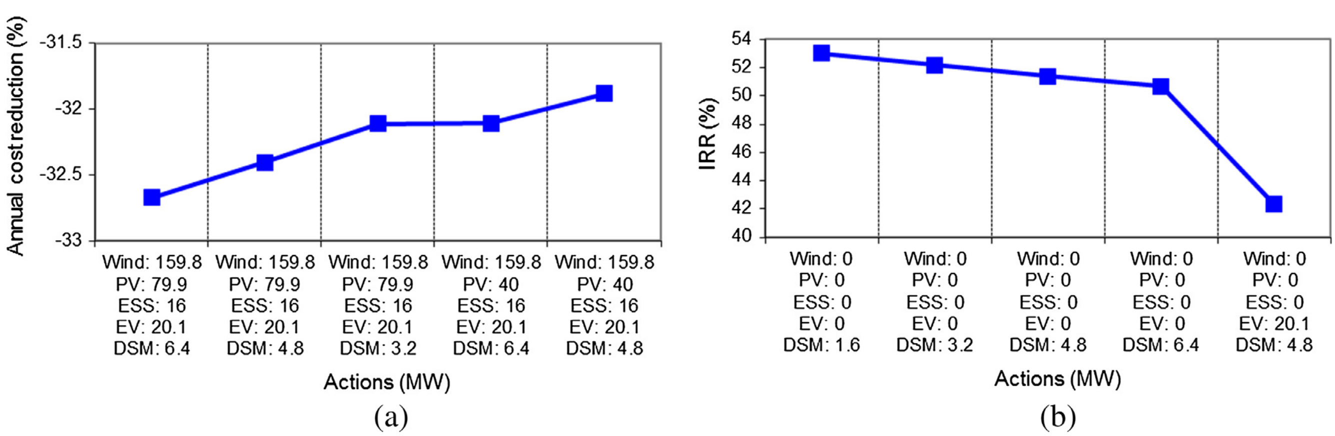

Fig. 8. Five best initiatives of prototype island 2: (a) in terms of annual cost reduction and (b) in terms of IRR.

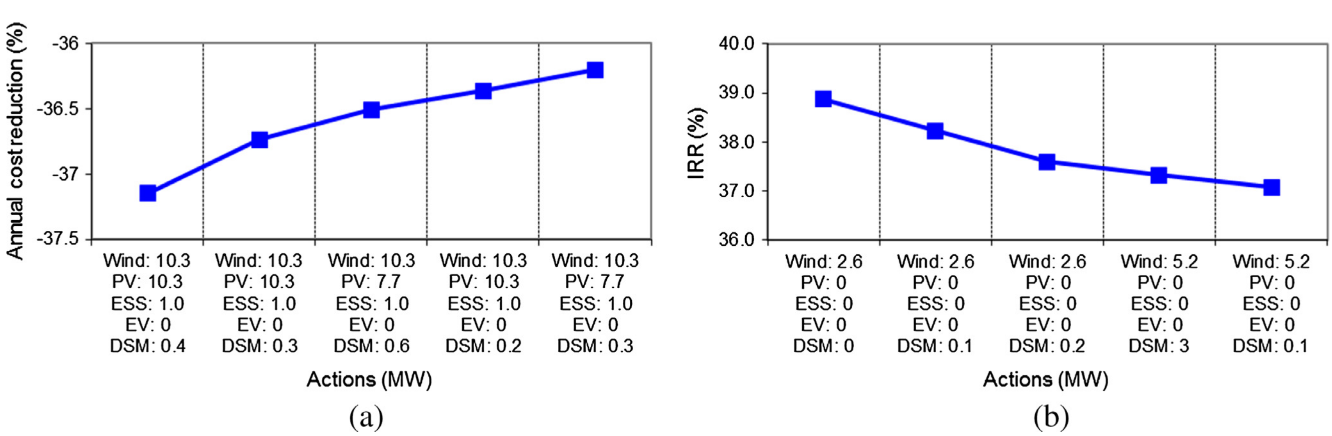

Fig. 9. Five best initiatives of prototype island 4: (a) in terms of annual cost reduction and (b) in terms of IRR.

whereas mostly wind together with DSM actions dominate in case of prototype island 4. It can be further seen that the largest cost reduction is not necessarily achieved when actions are at their highest penetration level. In case of prototype island 2, Fig. 8(a) indicates that PV actions reach PV capacities of up to 50% of the average demand, whereas EV actions only use EV capacities of up to 5% of the total number of cars. Note also that EV actions do not contribute to annual cost reductions in case of prototype island 4 (see Figs. 7 and 9(a)), since the reduction of both start up costs and reserve costs do not compensate the costs of increasing the demand. Fig. 10 compares generation and up-reserve provided by conventional generators for two different EV penetration levels for prototype island 2. The higher the EV penetration level, the lower the required up reserve, but the higher conventional generation. Whereas reserve reduction outweighs the increase in generation for a 21 MW EV penetration level, yielding to a system cost reduction of 1.6%, this is not true for a 81 MW EV penetration level, yielding to an increase in system costs. It can be concluded that the same single-action and multi-action initiatives in terms of relative size with regard to the prototype island have different impacts. In other words, different island power systems benefit from different initiatives.

Table 3 shows the best and the fifth best initiatives in terms of IRR for the five prototype islands. It can be inferred that single-action initiatives are in three of five islands the solutions with highest IRR. Multiple-actions with highest IRR are usually based on lower penetration levels of wind generation and DSM. Again, it can be concluded that successful initiatives are those that implement actions at very low penetration levels. From Table 3 it can be further inferred that larger islands (prototypes 1 and 2) benefit most from DSM and/or EV actions, whereas medium-sized to smaller islands (prototypes 3 to 5) mostly benefit from wind power and solar PV power actions. In case of smaller islands, wind power and solar PV power actions are accompanied by DSM actions, exhibiting however a slightly lower IRR than without the DSM actions. Finally, it is interesting to see that ESS actions are not present. The main reasons are the relative low penetration levels of wind and PV actions, where conventional generation still is able to

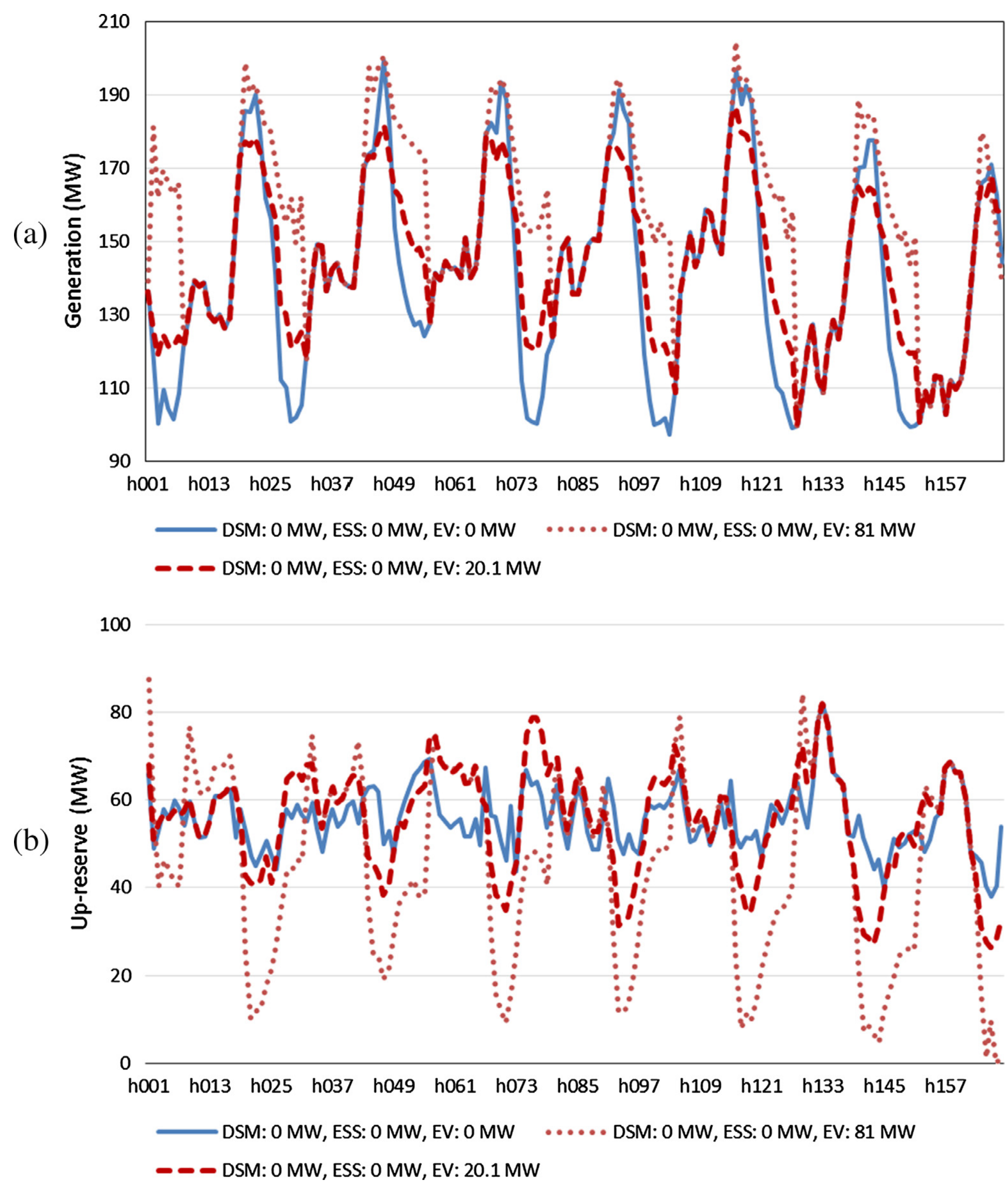

Fig. 10. Impact of EV penetration levels on generation and up-reserve provided by conventional generators of prototype island 2.

Table 3
Best and fifth best initiatives in terms of IRR for the considered prototype islands.

Prototype island	Initiative	Wind (MW)	PV (MW)	ESS (MW)	EV (MW)	DSM (MW)	IRR (%)
1	Best	0	0	0	0	12.1	46.7
1	5th best	303.3	0	0	0	12.1	21.4
2	Best	0	0	0	0	1.6	53.0
2	5th best	0	0	0	20.1	4.8	42.3
3	Best	8.8	8.8	0	0	0	67.3
3	5th best	8.8	8.8	0	0	1.4	65.4
4	Best	2.6	0	0	0	0	38.9
4	5th best	5.2	0	0	0	0.1	37.1
5	Best	0.5	0	0	0	0	34.2
5	5th best	0.5	0	0	0.	0.08	33.9

Table 4
Best and fifth best Initiatives in terms of IRR for the considered prototype islands with increased EV and DSM investment costs.

Prototype island	Initiative	Wind (MW)	PV (MW)	ESS (MW)	EV (MW)	DSM (MW)	IRR (%)
1	Best	0	0	0	0	12.1	22.3
1	5th best	303.3	0	0	0	12.1	19.3
2	Best	79.9	0	0	0	1.6	29.4
2	5th best	79.9	0	0	6	6.4	29.2
3	Best	8.8	8.8	0	0	0	67.3
3	5th best	8.8	8.8	0	0	1.4	63.5
4	Best	2.6	0	0	0	0	38.9
4	5th best	5.2	0	0	0	0.2	36
5	Best	0.5	0	0	0	0	34.2
5	5th best	0.95	0	0	0	0.02	31.6

provide sufficient reserve, and the investment costs. Note that previously reported research on ESS providing reserve and peak-shaving services yielded to an IRR around 8% [14].

Although investment costs of wind generation are rather well established, investment costs of PV, ESS and particularly EV and DSM cost might vary significantly. A further analysis of the IRR has been carried out by considering an investment cost of EV and DSM twice as high as assumed in Table 1. Table 4 shows again the best and the fifth best initiatives in terms of IRR for the five prototype islands. By comparing Table 4 with Table 3, a major change can be detected for island prototype 2, where the best and fifth best initiatives include now also wind actions. It can be also seen that IRR is readily lower (except for the best initiatives of prototype islands 3 and 5 consisting only of wind and PV actions, which are not affected by DSM and EV costs).

ESS would become part of competitive initiatives (among the five best) only if DSM and EV actions would be dramatically higher (4 to 5 times the assumed value) or when ESS cost would fall significantly. Actually, if a reduction of ESS investment cost by 50% is applied, the results of Table 3 remain the same except for prototype island 1, where the fifth best initiative now involves a 30.3 MW – 4 h ESS action and 48.5 MW DSM action. This confirms and adds to the statement in [11] on DSM as least cost and ESS as high cost options for island power systems.

5. Conclusion

The present paper has assessed single and multi-action initiatives that can transform island power systems into smart ones. Initiatives fostering the deployment of wind and PV generation, energy storage systems (ESS), demand-side management (DSM), and electric vehicle (EV) are considered. An hourly unit commitment on a weekly basis has been used to assess the impact of the initiatives on the system operation costs of five prototype island power systems. The economic assessment of the initiatives has been made in terms of their internal rate of return. The assessment of single and multi-action initiatives for five prototype islands representing nearly 60 island power systems quantifies which initiatives are most suitable for which type of island power system. It has been shown that islands of different sizes and features require different initiatives. Usually, single-action initiatives are most successful. Larger islands tend DSM dominated initiatives, whereas smaller islands tend to RES (wind and PV) initiatives. ESS actions also show a positive IRR, but far below the other actions.

References

[1] Vasconcelos H, Moreira C, Madureira A, Lopes JP, Miranda V. Advanced control solutions for operating isolated power systems: examining the portuguese islands. Electrificat Mag, IEEE 2015;3(1):25–35. March.
[2] Ministry of Industry, Tourism and Commerce of Spain, Resolution 9613 of 26 April 2006 establishing the operation procedures for insular and extra peninsular power systems (in Spanish), Official Bulletin of the State no. 219 of 31 May 2006; 2006. Available at: <http://www.ree.es>.
[3] EDF SEI, Référentiel technique (EDF Island Energy Systems Grid Code), REF 01–07; 2005–2011. Available: <http://sei.edf.fr> [in French].
[4] TRANSPOWER, Automatic under-frequency load shedding technical report - Appendix A: a collation of international policies for under-frequency load shedding, 7 August 2009; 2009. Available at: <http://www.systemoperator.co.nz>.
[5] Matsuura M. Island breezes. Power Energy Magaz, IEEE 2009;7(6):59–64. November–December 2009.
[6] Sigrist L, Egido I, Rouco L. A method for the design of UFLS schemes of small isolated power systems. Power Syst, IEEE Transact 2012;27(2):951–8. May.
[7] Hansen CW, Papalexopoulos AD. Operational impact and cost analysis of increasing wind generation in the island of crete. Syst J, IEEE 2012;6(2):287–95. June.
[8] Eurelectric, EU Islands: Towards a Sustainable Energy Future, D/2012/12.105/24; June 2012.
[9] Lund Peter D, Lindgren Juuso, Mikkola Jani, Salpakari Jyri. Review of energy system flexibility measures to enable high levels of variable renewable electricity. Renew Sustain Energy Rev 2015;45(May):785–807.
[10] Kondziella Hendrik, Bruckner Thomas. Flexibility requirements of renewable energy based electricity systems – a review of research results and methodologies. Renew Sustain Energy Rev 2016;53(January):10–22.
[11] Brouwer Anne Sjoerd, van den Broek Machteld, Zappa William, Turkenburg Wim C, Faaij André. Least-cost options for integrating intermittent renewables in low-carbon power systems. Appl Energy January 2016;161(1):48–74.
[12] Dominković DF, Bačeković I, Ćosić B, Krajačić G, Pukšec T, Duić N, et al. Zero carbon energy system of South East Europe in 2050. Appl Energy 2016;19. Available online, March.
[13] Ghofrani M, Arabali A, Etezadi-Amoli M, Fadali MS. Smart scheduling and cost-benefit analysis of grid-enabled electric vehicles for wind power integration. Smart Grid, IEEE Transact 2014;5(5):2306–13. Sept..

[14] Sigrist L, Lobato E, Rouco L. Energy storage systems providing primary reserve and peak shaving in small isolated power systems: an economic assessment. Int J Electr Power Energy Syst 2013;53:675–83. Diciembre.
[15] Hu Weihao, Su Chi, Chen Zhe, Bak-Jensen B. Optimal operation of plug-in electric vehicles in power systems with high wind power penetrations. Sustain Energy, IEEE Transact 2013;4(3):577–85. July 2013.
[16] Dietrich K, Latorre JM, Olmos L, Ramos A. Demand response in an isolated system with high wind integration. IEEE Trans Power Syst 2012;27(1):20–9. Febrero.
[17] Meschede Henning, Holzapfel Peter, Kadelbach Florian, Hesselbach Jens. Classification of global island regarding the opportunity of using RES. Appl Energy 2016;175(1):251–8. August.
[18] Schallenberg-Rodríguez Julieta, Notario-del Pino Jesús. Evaluation of on-shore wind techno-economical potential in regions and islands. Appl Energy 2014;124(1):117–29. July.
[19] Ranaboldo Matteo, Lega Bruno Domenech, Ferrenbach David Vilar, Ferrer-Martí Laia, Moreno Rafael Pastor, García-Villoria Alberto. Renewable energy projects to electrify rural communities in Cape Verde. Appl Energy 2014;118(1):280–91. April.
[20] Mandelli Stefano, Barbieri Jacopo, Mereu Riccardo, Colombo Emanuela. Off-grid systems for rural electrification in developing countries: definitions, classification and a comprehensive literature review. Renew Sustain Energy Rev 2016;58:1621–46. May.
[21] Mathiesen V, Lund H, Connolly D, Wenzel H, Østergaard PA, Möller B, et al. Smart Energy Systems for coherent 100% renewable energy and transport solutions. Appl Energy 2015;145(1):139–54. May.
[22] Lenzen Manfred, McBain Bonnie, Trainer Ted, Jütte Silke, Rey-Lescure Olivier, Huang Jing. Simulating low-carbon electricity supply for Australia. Appl Energy 2016;179(1):553–64. October.
[23] Chua KJ, Yang WM, Er SS, Ho CA. Sustainable energy systems for a remote island community. Appl Energy 2014;113(January):1752–63.
[24] Calise Francesco, Cipollina Andrea, Dentice d'Accadia Massimo, Piacentino Antonio. A novel renewable polygeneration system for a small Mediterranean volcanic island for the combined production of energy and water: dynamic simulation and economic assessment. Appl Energy 2014;135(15):675–93. December.
[25] Rouco L, Zamora JL, et al. Impact of wind power generators on the frequency stability of synchronous generators. Cigré Session 2008, Paris; 2008.
[26] Margaris ID, Papathanassiou SA, Hatziargyriou ND, Hansen A-D, Sorensen P. Frequency control in autonomous power systems with high wind power penetration. Sustain Energy, IEEE Transact 2012;3(2):189–99. April.
[27] Sigrist L, Egido I, Lobato Miguélez E, Rouco L. Sizing and controller setting of ultracapacitors for frequency stability enhancement of small isolated power systems. IEEE Trans Power Syst 2015;30(4):2130–8. July.
[28] Delille G, Francois B, Malarange G. Dynamic frequency control support by energy storage to reduce the impact of wind and solar generation on isolated power system's inertia. Sustain Energy, IEEE Transact 2012;3(4):931–9. Oct..
[29] Ueckerdt Falko, Pietzcker Robert, Scholz Yvonne, Stetter Daniel, Giannousakis Anastasis, Luderer Gunnar. Decarbonizing global power supply under region-specific consideration of challenges and options of integrating variable renewables in the REMIND model. Energy Econ 2016. http://dx.doi.org/10.1016/j.eneco.2016.05.012. ISSN 0140-9883.
[30] Palensky P, Dietrich D. Demand side management: demand response, intelligent energy systems, and smart loads. Indust Inform, IEEE Transact 2011;7(3):381–8. Aug..
[31] Pescador I. A sustainable energy future for islands: insights from EURELECTRIC report. GENERA 2013, Session on Island Power Systems, Madrid; 28 February 2013.
[32] Cantarellas A. El gas natural en las centrales térmicas de Baleares. Primeras Jornadas para un Sistema Eléctrico Sostenible en Les Illes Balears: de Sistema Aislado a Sistema Interconectado; 18 May 2012. Available at: <http://www.ree.es/>.
[33] Grima P. Flexible power plant. GENERA 2103, Session on Island Power Systems, Madrid; 28 February 2013.
[34] Granadino R. Rómulo: Interconexión eléctrica Península-Baleares. Primeras Jornadas para un Sistema Eléctrico Sostenible en Les Illes Balears: De sistema aislado a sistema interconectado; 18 May 2012. Available at: <http://www.ree.es/>.
[35] de la Torre JM. HVDC-250 kV Morvedre-Santa Ponsa Spanish mainland-Balearic Islands electric interconnection. GENERA 2013, Session on Island Power Systems, Madrid; 28 February 2013.
[36] Enemalta. Electricity interconnection Malta-Sicily. Available at: <https://www.enemalta.com.mt/> [accessed: 31 October 2013].
[37] Nielsen T. Faroe Islands. GENERA 2103, Session on Island Power Systems, Madrid; 28 February 2013.
[38] Tasmania Hydro. King Island: towards a sustainable, renewable energy future; 2008.
[39] European Investment Bank Press Release. Portugal: Azores receive funding for renewable energy and transmission; 29 April 2013. Available at: <http://www.eib.org/> [accessed: 31 October 2013].
[40] Gobierno de Canarias. Plan Energético de Canarias 2006-2015; 2006. Available at: <http://www.gobiernodecanarias.org/>.
[41] Gobierno de Canarias. Revisión Plan Energético de Canarias 2006–2015; May 2011. Available at: <http://www.gobiernodecanarias.org/>.
[42] IRENA. Electricity storage and renewables for island power: a guide for decision makers; May 2012. Available at: <http://www.irena.org/>.
[43] Arrojo J. Storage as a strategic tool to manage RES intermittency, adding value to the grid, DSM and change mobility. In: 3rd NESSIS Euroelectric conference toward a sustainable energy future for island systems; 26–27 April 2010, Las Palmas de Gran Canaria. Available at: <http://www.catedraendesared.ulpgc.es/>.
[44] Margina J. Almacenamiento de Energía: Proyecto Store. Cátedra Endesa Red, Universidad de Las Palmas de Gran Canaria; 15 December 2011. Available at: <http://www.catedraendesared.ulpgc.es/>.
[45] Rodriguez R. La central de bombeo de Soria-Chira. Cátedra Endesa Red, Universidad de Las Palmas de Gran Canaria; 25 November 2011. Available at: <http://www.catedraendesared.ulpgc.es/>.
[46] Endesa Press Release. Endesa instala en Canarias la primera planta de almacenamiento de energía de España; 22 August 2012. Available at: <http://www.endesa.com/es/> [accessed: 31 October 2013].
[47] Fastelli I. Energy storage on islands: a sustainable energy future for islands. Euroelectric, Workshop on EU Islands: Towards a Sustainable Energy Future, Brussels; 3 October 2012.
[48] Pons T. How to manage intermittency on islands? EDF Case studies. Euroelectric annual convention and conference, Malta; 5 June 2012.
[49] Barlier Y. How to manage intermittency on islands? Pritemps de la Recherche; 7 November 2012. Available at: <http://innovation.edf.com/fichiers/>.
[50] Buriez N, Mairem J, Barlier Y, Lascaud S. Will small-scale PV contribute to French insular grid operation? CIRED Workshop - Lisbon 29–30 May; 2012, Paper 261.
[51] Schütt R. Decentralized energy supply using the example of Pellworm. SEEEI Electricity; 2012, Eilat, Israel.
[52] Nielsen T, Windolf M. GRANI: A full scale "Live Lab" for new intelligent solutions within renewable energy. In: 3rd NESSIS Euroelectric conference toward a sustainable energy future for island systems; 26–27 April 2010, Las Palmas de Gran Canaria.
[53] Kumagai J. The Smartest, greenest grid. IEEE Spectr 2013;50(5). May.
[54] Piernavieja G. El Hierro Wind-Pumped-Hydro Power Station Penetration. Estoril; 26 March 2010. Available at: <http://www.storiesproject.eu>.
[55] Geun PM. Experience of Jeju smart grid test-bed and national strategy. GENERA 2013, Session on Island Power Systems, Madrid; 28 February 2013.
[56] Botelho F. The Azores and the Renewables. GENERA 2013, Session on Island Power Systems, Madrid; 28 February 2013.
[57] Da Costa PJ. Case studies for Sustainable Energy on Islands: EDA Experience. Euroelectric, Workshop on EU Islands: Towards a Sustainable Energy Future, Brussels; 3 October 2012.
[58] Egido I, Rouco L, Fernández-Bernal F, Rodríguez A, Rupérez J, Rodríguez-Bobada F, et al. Máxima generación eólica en sistemas eléctricos aislados. XII ERIAC (Encuentro Regional Iberoamericano de Cigré), Foz de Iguazú; 20–24 Mayo 2007.
[59] Schneuwly A. High reliability power backup with advanced energy storage – white paper. SA: Maxwell Technologies; 2006.
[60] Kaneshiro RS. Hawaii Island (Big Island) Integration of Renewable Energy. GENERA 2013, Session on Island Power Systems, Madrid; 28 February 2013.
[61] Eco-Island project website <http://www.eco-island.org.uk/> [accessed: 31 October 2013].
[62] Dafni Network website <http://www.dafni.net.gr/en/home.htm> [accessed: 31 October 2013].
[63] EDF. Développer Les Énergies Renouvelables". Available at: <http://reunion.edf.com/> [accessed: 31 October 2013].
[64] Hand D, Mannila H, Smyth P. Principles of data mining. MA, USA: MIT Press, Boston; 2001.
[65] JRC, Driving and parking patterns of European car drivers – a mobility survey; 2012.
[66] Egido I, Lobato E, Rouco L, Sigrist L, Barrado A, Fontela P, et al. Store: a comprehensive research and demostration project on the application of energy storage systems in island power systems, 46 CIGRE Session - CIGRE 2016. París, Francia; 21–26 Agosto 2016.
[67] Electric energy storage technology options: a white paper primer on applications, costs, and benefits. EPRI, Palo Alto, CA; 2010, 1020676.
[68] IRENA. Battery storage for renewables: Market Status and Technology Outlook; January 2015.
[69] US Department of Energy and Federal Energy Regulatory Commission, Framework for Evaluating the Cost-Effectiveness of Demand Response; June 2010.
[70] Xcel Energy, 2014 Demand-Side Management Plan, July 1; 2013.
[71] Ministerio de Industria, Energía y Turismo. Real Decreto 738/2015, de 31 de julio, por el que se regula la actividad de producción de energía eléctrica y el procedimiento de despacho en los sistemas eléctricos de los territorios no peninsulares. Boletín Oficial del Estado, núm. 183, de 1 de agosto de 2015, páginas 66752 a 66903; 2015.
[72] Luenberger DG. Investment science. 2nd ed. Oxford University Press; 2013.
[73] Lin Chia-Hung, Hsieh Wei-Lin, Chen Chao-Shun, Hsu Cheng-Ting, Ku Te-Tien, Tsai Cheng-Ta. Financial analysis of a large-scale photovoltaic system and its impact on distribution feeders. Indust Appl IEEE Transact 2011; 47(4): 1884–1891 [July–Aug. 2011].
[74] Kornelakis A, Koutroulis E. Methodology for the design optimisation and the economic analysis of grid-connected photovoltaic systems. Renew Power Gener, IET 2009;3(4):476–92. December.
[75] IRENA. Renewable energy country profiles: special edition on the occasion of the Renewables and Islands Global Summit; 6–7 September 2012. Available at: <http://www.irena.org/>.

[76] US Energy Information Agency website; 2013. <http://www.eia.gov> [accessed: 31 October 2013].
[77] EDF en Corse website; 2013. <http://corse.edf.com/> [accessed: 31 October 2013].
[78] EDF en La Reunion website; 2013. <http://reunion.edf.com/> [accessed: 31 October 2013].
[79] EDF en Martinique website; 2013. <http://martinique.edf.com> [accessed: 31 October 2013].
[80] EDF en Gudaloupe wbesite; 2013. <http://guadeloupe.edf.com> [accessed: 31 October 2013].
[81] Electricidade dos Azores website; 2013. <http://www.eda.pt/> [accessed: 31 October 2013].
[82] Electricidade do Madeira. Caracterização da Rede de Transporte e Distribuicao em AT e MT; 2012. Available at: <http://www.eem.pt/>.
[83] Electricity Authority of Cyprus website; 2013. <http://www.eac.com.cy/EN/Pages/Home.aspx> [accessed: 31 October 2013].
[84] Enermalta website; 2013. <http://www.enemalta.com.mt> [accessed: 31 October 2013].
[85] Manx Electricity Authority website; 2013 <http://www.gov.im/mea/> [accessed: 31 October 2013].
[86] Jersey Electricity website; 2013. <http://www.jec.co.uk> [accessed: 31 October 2013].
[87] Guernesey Electricity website; 2013. <http://www.electricity.gg/> [accessed: 31 October 2013].
[88] Comisión Nacional de Energía. Informe marco sobre la demanda de energía eléctrica y gas de natural, y su cobertura. Año 2012; April 2013. Available at: <http://www.cne.es/>.
[89] Schröder Andreas, Kunz Friedrich, Meiss Jan, Mendelevitch Roman, von Hirschhausen Christian. Current and prospective costs of electricity generation until 2050, Data Documentation, DIW, No. 68; 2013.
[90] Xcel Energy, Demand-side Management Annual Status Report, April 1; 2013.
[91] US Department of Energy, Automated Demand Response Benefits California Utilities and Commercial & Industrial Customers; September 2014.
[92] Transport for London. Guidance for implementation of electric vehicle charging infrastructure; April 2010.
[93] C2ES. Business Models For Financially Sustainable EV Charging Networks; March 2015.