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Techno-Economic Prospects of High Wind Energy Share in Remote vs. Interconnected Island Grids

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***Abstract*—**On the basis of comparative analysis of alternative "development scenarios" for electricity generation, the main objective of the present study is to investigate the techno-economic viability of high wind energy (WE) use at the local (island) level. An integrated theoretical model is developed based on first principles assuming two main possible scenarios for covering future electrification needs of a medium–sized Greek island, i.e. Lesbos. The first scenario (S1), assumes that the island will keep using oil products as the main source for electricity generation. The second scenario (S2) involves the interconnection of the island with the mainland grid to satisfy part of the electricity demand, while remarkable WE penetration is also achieved. The economic feasibility of the above solutions is investigated in terms of determining their Levelized Cost of Energy (LCOE) for the time-period 2020-2045, including also a sensitivity analysis on the worst/reference/best Cases. According to the results obtained, interconnection of Lesbos Island with the mainland grid (S2) presents considerable economic interest in comparison to autonomous development (S1) with WE having a prominent role to this effect.

***Keywords*—**Electricity generation cost, levelized cost of energy, mainland, wind energy surplus.

I. Introduction

THE electrification in non-interconnected Greek islands is mainly based on fossil fuel consumption and is -in most cases- characterized by high electricity generation costs which may exceed 200€/MWh. At the same time, the contribution of Renewable Energy Sources (RES) to islands' energy supply is still limited and the remarkable local RES-based potential remains unexploited. In fact, autonomous electrical networks are subject to constraints on renewable energy absorbance, which are posed mainly by the operation of the oil-fired power stations [1], [2]. Another aggravating factor for these constraints is the stochastic availability of renewable energy (especially wind), as well as the remarkable variation of the daily and seasonal local electrical load demand during a year due to the touristic character of the islands. Thus, in order to avoid severe renewable energy curtailments, installation of new RES-based projects is discouraged after exceeding a certain capacity limit in case that a remote island grid has already reached its "saturation" point [3]. On the other hand, Greece has undersigned commitments in accordance with EU policies which have as a main feature the large-scale penetration of RES and the protection of the environment. A prerequisite for the country in order to meet these commitments is the implementation of a national fossil-to-renewable energy transition plan and the complete restructuring of the power sector. Under this framework, interconnection of Aegean Sea islands with the mainland grid can be of great interest, in order to reduce expensive oil-fired power generation and increase the renewable energy (mainly wind) contribution at both the national and local (island) level.

In fact, Greek islands' interconnection with the mainland grid is a crucial issue that has been examined many times in the past [4], [5]; however, most of these attempts did not succeed, despite the reported economic and environmental benefits for the entire Greek territory. Nevertheless, the continued maturation of new technologies, especially the DC transmission systems [6], but also the increasingly relevant activity that took place in recent years on a global scale with the design and construction of several interconnections between countries (such as Norway with the Netherlands, Estonia with Finland etc.) or islands with mainland systems, brought back to the fore the issue of remote islands' interconnection with mainland systems and created the conditions for successful implementation of similar projects in Greece [7], [8].

In this study, the interconnection of Greece's third largest island with the mainland grid is evaluated from the energy-economic point of view, as an alternative to its current autonomous operation, which is fed mostly by a local oil-fired power station. In this context, at first, the system's energy performance is modelled over a 25-year period with the use of a simulation tool based on first principles. Next, the economic feasibility of the two solutions is investigated in terms of a preliminary study by determining their Levelized Cost of Energy (LCOE), while also including a sensitivity analysis with respect to possible deviations in the values of the most uncertain variables, in order to identify the worst (pessimistic-Pe), reference/baseline (most likely- Ba) and best (optimistic-Op) output results.

II. Case Study Presentation

The island used as a study case is Lesbos. It is located in the North-Eastern part of the Aegean Sea (Fig. 1) and has an area of 1,630 km^2. It represents a typical case of a medium-sized Greek island which faces significant electricity generation problems resulting in several black-outs, especially during the summer months. The system is primarily supplied by an Autonomous Power Station (APS), comprising several oil-fired generators, which on an annual basis consume significant

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oil-fuel quantities (approx. 60,000t per year). The maximum available power of the APS is currently close to 80MW. The wind energy (WE) potential of the island is quite significant, with the annual mean wind speed exceeding 8m/s (at 10m height). In fact, three major wind farms (WFs) of total rated power of 13.7MW contribute to the electrification of the island. According to official data it appears that the contribution of the existing WFs to the annual energy supply is currently quite small, i.e. approx. 15% of annual demand (Fig. 1).

As far as solar power is concerned, with an average annual radiation per square meter being between 1,700 and 1,800kWh/m^2, the total installed photovoltaic (PV) capacity has reached 8.8MW. PVs annual energy production is about 1,550MWh$_e$ per installed MW on an inclined plane (30^o).

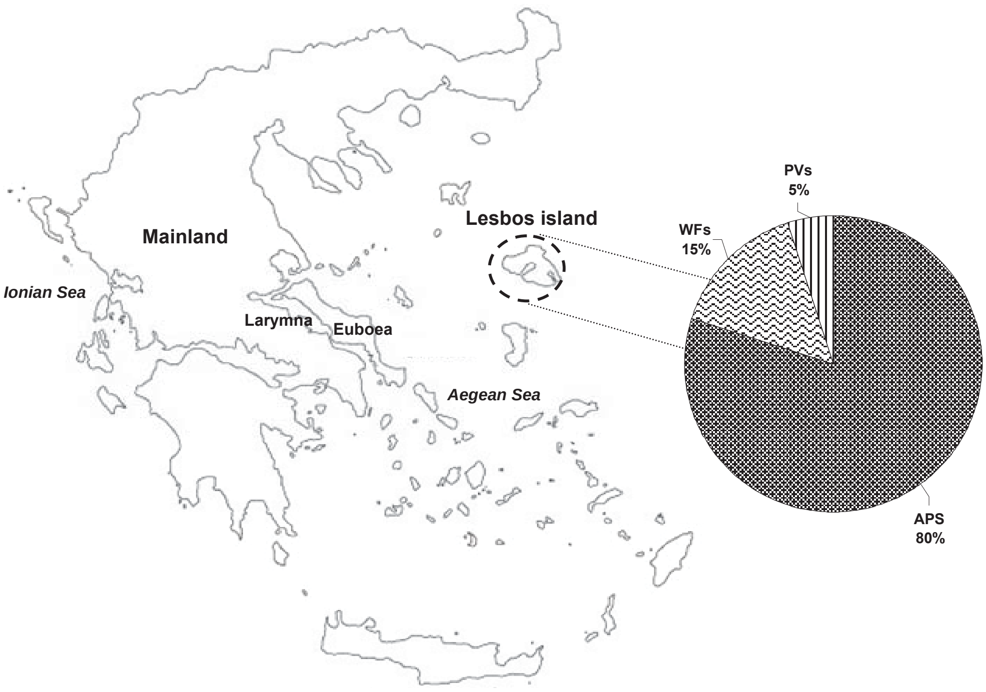

Fig. 1 A map of Greece and Lesbos island along with island's annual electricity generation mix

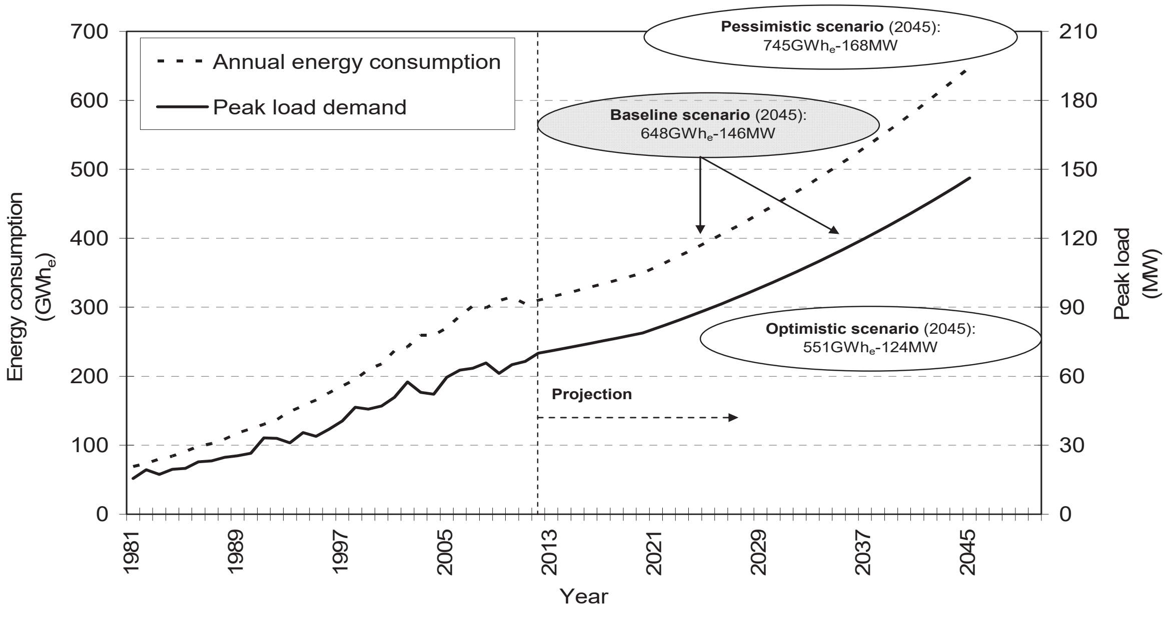

Fig. 2 Evolution in energy consumption and peak load demand of Lesbos island

Currently, the annual energy consumption of the island is about 300GWh$_e$, while the peak load demand is approx. 70MW. The hourly load demand time-series, which is taken into account in the simulations in the present study, is adjusted every year considering a realistic annual growth rate of the order of 1.5% up to 2020, while for the next 25-year period until 2045 the respective growth rate is considered equal to 2.5% (Fig. 2). Thus, according to the "baseline Case" (or reference Case), the estimated annual energy consumption at the end of the project's lifetime (2045) is estimated equal to ~648GWh$_e$ and the peak load demand equal to ~146MW. It is noted that further information on the three investigated Cases (i.e. optimistic, baseline, pessimistic) is given in the next Sections.

III. Energy Model

A. Scenario 1(S1)

In Scenario 1 it is assumed a continuation of present electricity-related policies and that oil will remain the dominant fuel in electricity generation on Lesbos island during the next years. In order to determine RES penetration (mainly wind) ability into the island's energy balance, the forecasted load demand (Fig. 2) over the whole time-period of the project (2020-2045) is taken into account, as well as the methodology presented in the Appendix (see also previous work of the authors: [9], [10]). Additionally, the existing thermal power units' main characteristics (e.g. dispatch order, type of fuel consumed by each unit, technical minima, maximum power output, etc.) are considered together with any potential future modifications/reinforcements in order to always satisfy the demand during the time-period under investigation. For example, according to the baseline Case (S1-Ba) it is assumed that in 2020 the APS will comprise nine thermal power units (4 existing: 47.5MW and 5 new: 55MW) of total rated power 102.5MW, while every five years' thermal capacity is properly modified (Table I) in order to meet the forecasted load (Fig. 2).

The wind power installed capacity is parametrically examined starting from the existing 13.7MW (~14MW) and ending to 67.7MW (~68MW) with the step of 9MW. Note that the examination of greater nominal power in this scenario would have not made any sense since the expected WE curtailments would be large leading to non-viable investments. On the other hand, for 2020-2029, it is considered that PVs will achieve their upper limit capacity, which has been set equal to 28.5% [11], [12] of the estimated mean load demand by 2020, corresponding to 11MW (applications for new installations already exceed these limits). For the years 2030-2045, installed PV capacity is taken equal to 26MW, considering a relatively conservative growth of the permitted upper limit (from 28.5 to 35%), as a continuation of the first amendment made by RAE increasing the specific limit of Decisions 85/2007 and 96/2007 with the relevant Decisions 702/2008 and 703/2008. In order to calculate PVs energy production, time-series solar radiation data on a horizontal plane representative for the island conditions are used along with a typical PV collector power curve [13]. At this point it should be noted that given the technical characteristics of PV systems and their great dispersion all over the island, their operation is difficult to control, so it is assumed that there is no limitation in PV power absorbed by the local grid. Thus, the benefits of dispersed PV energy production close to consumers are considered by taking into account specific PV power output, especially during midday hours, which is absorbed in preference to WFs.

TABLE I
PLANNING PROCEDURES OF THE REQUIRED INSTALLATIONS

		2020	2025	2030	2035	2040
S1-Op	Installation of new WFs	+				
	Installation of new PV stations (17.2MW)	+(2.2)		+(15)		
	Installation of new thermal power units (155MW)	+(45)	+(10)	+(60)	+(15)	+(25)
	Disposal of old thermal power units (86MW)	+ (38.5)		+ (47.5)		
S1-Ba	Installation of new WFs	+				
	Installation of new PV stations (17.2MW)	+(2.2)		+(15)		
	Installation of new thermal power units (170MW)	+(55)	+(15)	+(60)	+(15)	+(25)
	Disposal of old thermal power units (86MW)	+ (38.5)		+ (47.5)		
S1-Pe	Installation of new WFs	+				
	Installation of new PV stations (17.2MW)	+(2.2)		+(15)		
	Installation of new thermal power units (200MW)	+(75)	+(15)	+(60)	+(25)	+(25)
	Disposal of old thermal power units (86MW)	+ (38.5)		+ (47.5)		
S2-Op	Installation of new WFs	+				
	Installation of new PV stations (17.2MW)	+(2.2)		+(15)		
	Interconnection with mainland	+				
S2-Ba	Installation of new WFs	+				
	Installation of new PV stations (17.2MW)	+(2.2)		+(15)		
	Interconnection with mainland	+				
S2-Pe	Installation of new WFs	+				
	Installation of new PV stations (17.2MW)	+(2.2)		+(15)		
	Interconnection with mainland	+				

B. Scenario 2(S2)

Scenario 2 investigates the interconnection of the island with the mainland grid with the objective of complete removal (either directly or after a certain trial operation period of the project) of the thermal power plant and the parallel exploitation of the high local WE potential, which otherwise would not be possible due to the well-known technical limitations. Thus, it is assumed that a large part of the island's energy needs will be satisfied by local RES (mainly wind), while the rest will be covered by electricity imports from the mainland. More specifically,

$$N_L(t) \le N_{RES}(t) \to N_R(t) = 0 \tag{1}$$

$$\begin{aligned} &N_L(t) > N_{RES}(t) \to \\ &N_R(t) = N_L(t) - N_{RES}(t) = N_{tr(m\to i)}(t)\cdot(1-\delta N_{tr}) \end{aligned} \tag{2}$$

where "N_L" is the hourly electricity demand of the island (forecasted load), "$N_{tr(m\to i)}$" is the power which is imported through the submarine cables from the mainland grid to the island and "N_{RES}" is the power output of local RES applications. Furthermore, "δN_{tr}" represents the percentage of power transmission losses (3.8%) through the submarine cables and "N_R" is the rest of load demand which cannot be covered by local RES production.

In the case that the power output of local RES applications "N_{RES}" is higher than the island's load demand, the power surplus "$N_{eRES(i\to m)}$" (primarily wind power as respective PV curtailments are neglected) is forwarded through the submarine cables from the island to the mainland. Thus,

$$N_{RES}(t) \le N_L(t) \to N_{eRES(i\to m)}(t) = N_{tr(i\to m)}(t) = 0 \tag{3}$$

$$\begin{aligned} &N_{RES}(t) > N_L(t) \to \\ &N_{eRES(i\to m)}(t) = N_{RES}(t) - N_L(t) = N_{tr(i\to m)}(t)\cdot(1-\delta N_{tr})^{-1} \end{aligned} \tag{4}$$

where "$N_{tr(i\to m)}$" represents the amount of wind power surplus that reaches the mainland taking into account the power losses of the interconnection.

Installed PVs power capacity is taken the same as in S1, while WF installations are again parametrically examined starting from the existing 13.7MW (~14MW) and ending at 310.7MW (~311MW). Note that there is already great interest from private investors concerning new WF installations of the order of 300MW. One example is the privately-owned project called "Aegean Link", which aims to install 306MW of wind power on the western part of the island [14].

The technical features of the corresponding interconnection are determined on a case-by-case basis (e.g. power capacity of the cables "N_{tr}^{rated}", power of the inverters etc.). Particularly, they are defined every time based on the maximum -resulted from the simulations- supplied energy from the island to the mainland grid and vice versa, provided that the forecasted peak load demand "$N_L^{\max}$" is always satisfied over the entire lifetime of the investment, even in the case of zero power output of the local RES applications ($N_{RES}(t) = 0$). Furthermore, it is assumed that the system operator (project owner) bears the cost to install two pairs of unipolar cables (4 unipolar DC cables), so as to ensure -as an extreme case- power transmission from the mainland to the island equal to 100% of the required capacity in case of failure of the one pair of submarine cables.

Based on the above assumptions, determination of total power capacity of the interconnection is bounded by the following two conditions:

$$2N_L^{\max}\cdot(1-\delta N_{tr})^{-1} \ge N_{e_w(i\to m)}^{\max} \to N_{tr}^{rated} = 2N_L^{\max}\cdot(1-\delta N_{tr})^{-1} \tag{5}$$

$$2N_L^{\max}\cdot(1-\delta N_{tr})^{-1} < N_{e_w(i\to m)}^{\max} \to N_{tr}^{rated} = N_{e_w(i\to m)}^{\max} \tag{6}$$

where "$N_{e_w(i\to m)}^{\max}$" is the maximum resulted amount of wind power surplus that is forwarded to the mainland grid.

IV. Economic Analysis

A. Scenario 1(S1)

In the present analysis, the Levelized Cost of Energy (LCOE) is selected as the objective function that should be determined in order to realize the economic effectiveness of each investigated scenario. In general, the LCOE includes all lifecycle costs over the considered economic lifetime of a project "n", i.e. capital costs, ongoing system-related costs - along with the total electricity produced- and converts them into a common metric, e.g. €/kWh. Note that in the present study, for simplicity reasons, the residual value at the end of the investment's lifetime is assumed to be zero. Thus, the LCOE may be defined as:

$$LCOE = \frac{\sum_j^n [I\widetilde{C}_{o(j)}^{PPC} + \widetilde{C}_{(j)}^{PPC} + I\widetilde{C}_{o(j)}^{w} + \widetilde{C}_{(j)}^{w} + \widetilde{C}_{RES(j)}^{FIT,i}]}{\sum_j^n [E_{PPC(j)} + E_{w(j)} + E_{PV(j)}]\cdot f_i} \tag{7}$$

where "$I\widetilde{C}_{o(j)}^{PPC}$" is the initial cost for the installation of new thermal power units and "$E_{PPC(j)}$" is the thermal energy production during the year j. Symbol "~" represents costs expressed in terms of present values using a specific discount rate "i" (8%). It is noted that all the estimated cash flows are discounted to the year 2015 (j=0). "f_i" is the escalation factor which is introduced in order to appraise the time value of money. Thus,

$$f_i = \left(\frac{1}{1+i}\right)^j \tag{8}$$

Investment cost per thermal power unit at the year j may be defined as:

$$I\widetilde{C}_{o(j)}^{PPC} = P_{r_{dv}}\cdot N_{dv}\cdot f_i \tag{9}$$

where "$P_{r_{dv}}$" is the price of the investment cost (in €/kW) per thermal power unit (or plant) and "N_{dv}" its nominal power (in kW). Investment cost for oil-fired plants during the whole period of 2020-2045 is taken equal to 1,100€/kW, as it is considered a mature technology possessing for many years a large share in the electricity sector and is not expected to change in the future [15].

In (7), "$\widetilde{C}_{(j)}^{PPC}$" represents the total operation and maintenance cost of the thermal power plant for year *j*. Particularly, the annual cost (in present values) per thermal power unit (or plant) comprises the maintenance cost "$\widetilde{C}_{PPC(j)}^{O\&M}$", fuel cost (including any other additional charges) "$\widetilde{C}_{PPC(j)}^{fuel}$" [16], as well as the corresponding market cost for CO_2 allowances "$\widetilde{C}_{PPC(j)}^{CO_2}$", i.e.:

$$\widetilde{C}_{(j)}^{PPC} = \widetilde{C}_{PPC(j)}^{O\&M} + \widetilde{C}_{PPC(j)}^{fuel} + \widetilde{C}_{PPC(j)}^{CO_2} \tag{10}$$

The annual maintenance cost "$\widetilde{C}_{PPC(j)}^{O\&M}$" maybe expressed as:

$$\widetilde{C}_{PPC(j)}^{O\&M} = m_{PPC}^{O\&M} \cdot E_{PPC(j)} \cdot f_i \tag{11}$$

where "$m_{PPC}^{O\&M}$" is expressed in €/kWh (i.e. 0.004€/kWh) and includes various expenses such as salaries and costs for maintenance of the thermal power units.

Subsequently, the annual fuel cost maybe expressed as:

$$\widetilde{C}_{PPC(j)}^{fuel} = \left(FQ_{(j)} \cdot c_{fuel} + c_{fuel}^{others} \cdot E_{PPC(j)}\right) \cdot f_i \tag{12}$$

where "$FQ_{(j)}$" is the total fuel consumption (in kg) for year *j*, "c_{fuel}" is the fuel cost (in €/kg) and "c_{fuel}^{others}" (Table II) represents any other possible additional charges (in €/kWh).

TABLE II
DATA FOR THERMAL POWER GENERATION DURING 2020-2045 [16]-[18]

Type	SFC[a] (kg/kWh)			Additional charges for fuel oil (€/kWh)	Market cost for CO_2 allowances	
	0.5	0.75	1		kg CO_2/ kg fuel	€/kg CO_2
New unit (mazout)	0.211	0.202	0.201	0.035	3.109	0.020
Existing unit (mazout)	0.211	0.202	0.201		3.109	
Existing unit (diesel) (gas turbine)	0.358	0.318	0.292		3.162	
New unit (diesel)	0.358	0.318	0.292		3.162	

[a] Specific Fuel Consumption

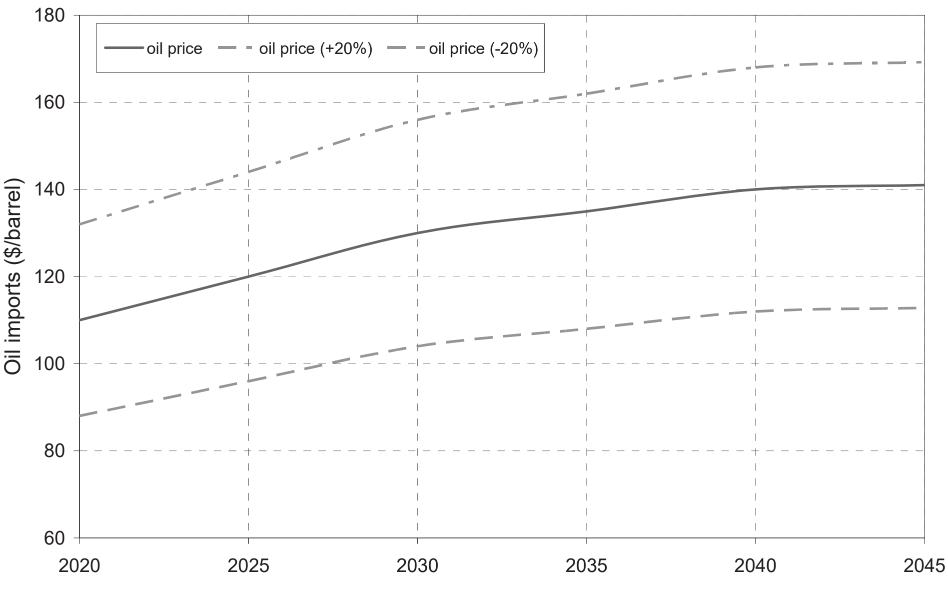

Fig. 3 Projected evolution in oil price

For oil imports an annual price adjustment up to 2035 is considered based on the scenario of current policies of "World Energy Outlook, 2012 Edition" [19] published by the International Energy Agency in November 2012. Fig. 3 presents the evolution in oil prices from 2020 to 2045 as well as a fluctuation rate of the order of ±20%. From 2035 to 2045 the depicted prices are an estimate, assuming constant deceleration of the increasing rates [17]. The euro-dollar exchange rate during the period of the analysis is taken 1€=$1.3. Furthermore, the market cost for CO_2 allowances maybe calculated as:

$$\widetilde{C}_{PPC(j)}^{CO_2} = EQ \cdot FQ_{(j)} \cdot p_{CO_2} \cdot f_i \tag{13}$$

where "EQ" are the CO_2 emission quantities which correspond to 1 kg of fuel oil (kg CO_2/kg fuel) (Table II) and "p_{CO_2}" is the market cost for CO_2 allowances (in €/kg CO_2). The average price for CO_2 allowances for the period 2020-2045 is taken by considering in 2020 a price equal to 20€/t. Subsequently, it is assumed that the development of average prices will follow the estimated trend in the baseline scenario (20€/t) of the European roadmap for reducing greenhouse gas emissions by 2050, where it is considered that current trends and policies will continue to be valid [17].

In (7), "$I\widetilde{C}^{w}_{o(j)}$" represents the initial cost for new WE applications (state subsidization or other incentives are not taken into account). More specifically, it may be estimated as:

$$I\widetilde{C}^{w}_{o(j)} = P_{r_w} \cdot N^{rated}_{w} \cdot f_i \tag{14}$$

where "P_{r_w}" is the initial cost of the power station in €/kW and "N^{rated}_{w}" (in kW) its nominal power. The capital cost for new WF installations in all scenarios is assumed 1,100€/kW by 2020 [15].

Following, "$\widetilde{C}^{w}_{(j)}$" (or $\widetilde{C}^{O\&M}_{w(j)}$) denotes the annual maintenance and operation cost of the new WE projects (other costs, such as taxes etc., are not taken into account), namely,

$$\widetilde{C}^{O\&M}_{w(j)} = m^{O\&M}_{w} \cdot IC^{w}_{o(j)} \cdot f_i \tag{15}$$

where "$m^{O\&M}_{w}$" represents a specific percentage (e.g. 3%) of the initial cost of the investment ($IC^{w}_{o(j)} = P_{r_w} \cdot N^{rated}_{w}$).

Finally, the LCOE is determined by the annual renewable energy payments "$\widetilde{C}^{FIT,i}_{RES(j)}$" to renewable energy producers (mainly for existing applications) depending on the technology and the corresponding compensation mechanism (feed-in-tariff) for the non-interconnected islands, i.e.:

$$\begin{aligned}\widetilde{C}^{FIT,i}_{RES(j)} &= \widetilde{C}^{FIT,i}_{w(j)} + \widetilde{C}^{FIT,i}_{PV(j)} = \\ &= p^{FIT,i}_{w} \cdot E_{w(j)} \cdot f_i + p^{FIT,i}_{PV} \cdot E_{PV(j)} \cdot f_i\end{aligned} \tag{16}$$

with "$\widetilde{C}^{FIT,i}_{w(j)}$" and "$\widetilde{C}^{FIT,i}_{PV(j)}$" expressing the annual payments to investors of existing WE installations (13.7MW) and PV projects (11-26MW), respectively. "$E_{w(j)}$" and "$E_{PV(j)}$" represent the annual wind and PV energy production which is absorbed by the local grid. "$p^{FIT,i}_{w}$" and "$p^{FIT,i}_{PV}$" (in €/kWh or €/MWh) are the corresponding selling prices to the grid which are assumed to remain stable in the coming years. Thus, the selected feed-in-tariff (as for non-interconnected Greek islands) for WE projects is taken equal to 99.45€/MWh, while for PVs it is considered equal to 95€/MWh [20].

B. Scenario 2(S2)

In this scenario, the LCOE (in €/kWh or €/MWh) expressed in present values is defined as:

$$LCOE = \frac{\sum_{j}^{n} [I\widetilde{C}^{inter}_{o(j)} + I\widetilde{C}^{w}_{o(j)} + \widetilde{C}^{w}_{(j)} + \widetilde{C}^{FIT,i}_{RES(j)} + EP\widetilde{C}_{m(j)}]}{\sum_{j}^{n} [E_{tr(m\to i)(j)} + E_{w(j)} + E^{w}_{e(i\to m)} + E_{PV(j)}] \cdot f_i} \tag{17}$$

where "$EP\widetilde{C}_{m(j)}$" is the Energy Production Cost (EPC) on the mainland (depending on the power source) and "$E_{tr(m\to i)(j)}$" is the annual energy imported from the mainland's grid to the island. "$E^{w}_{e(i\to m)(j)}$" is the WE surplus that is delivered to the mainland's grid for year j. "$I\widetilde{C}^{inter}_{o(j)}$" is the investment cost in present values. It is noted that (17) does not include -for simplicity reasons- other costs, such as the annual cost for maintenance of the interconnection. Furthermore, it does not include any capital expenditures for new power units on the mainland covering the expected energy demand of the island, as it is assumed that the demand will be covered by existing and planned power units. Note that at present, installed firm power capacity on the mainland is already approximately 13GW (10GW thermal and 3GW hydroelectric power). On the other hand, in the extreme Cases (optimistic and pessimistic Cases, Fig. 1) examined up to 2045, the peak load demand of the island is estimated between 124 and 168MW (±15% variation of the estimated values in the baseline Case), i.e. about 1% of the already installed power capacity on the mainland.

The average EPC on the mainland, for the present study, is assumed equal to the average production cost of a Natural Gas (NG)-fired combined cycle power plant (or unit). According to estimations found in technical reports [4], [8], [21], the EPC of a NG-fired power plant (neglecting the contribution of the initial cost) is about 67€/MWh, of which 63€/MWh comprise the fuel cost and 4€/MWh the operation and maintenance cost. Taking also into account the environmental impact of CO_2 emissions (~10€/t CO_2), the present production cost of the NG-fired power plant (or unit) is finally estimated equal to 71€/MWh, without including other associated cost components (according to the energy methodology of ExternE 1997 and 2005), such as the impact on residents' health (mortality-morbidity), accidents, air pollution, etc. It is noted that according to the UNO's Intergovernmental Panel on Climate Change (IPCC), NG releases 56.1t CO^2/TJ. Considering the efficiency performance of the station equal to 45%, it is estimated that NG emits about 0.4t CO_2 per produced MWh [21]. As for the calculation of the total EPC in the mainland for the period 2020-2045, the following assumptions are made:

- The average price for CO_2 allowances is taken again equal to 20€/t CO_2 [17].
- The long-term evolution in total EPC and more specifically, the evolution in NG-fuel cost is directly connected to global oil price fluctuations [17], [19], following an average annual increase rate of the order of about 1% (Fig. 4).

For the economic evaluation of the interconnection, several cost parameters should be assessed depending on the selected technical characteristics of the project. So, a rough estimate at this preliminary stage may include the required electric equipment cost "$IC_{o(plant)(j)}$" (e.g. substations, AC/DC or/and DC/AC converters, etc.), as well as the cost of the interconnection cables "$IC_{o(cables)(j)}$". Thus,

$$IC_{o(j)}^{inter} = IC_{o(plant)(j)} + IC_{o(cables)(j)} \tag{18}$$

As already mentioned, it is assumed that the project owner bears the cost to install two pairs of unipolar cables. Furthermore, it is assumed that this scenario also includes the installation of two pairs of substations with two converters AC/DC or DC/AC, one pair to the island and the other to the mainland.

An accurate assessment of the capital cost of the interconnection -in a preliminary stage- is quite difficult as all associated expenses strongly depend on market conditions, as well as on certain project peculiarities that may emerge in a later, more mature stage of the study. Thus, for safety reasons, although specific costs derive from bibliography [5], it is chosen -on the basis of investigating the worst/reference/best Cases- a variation of the estimated capital cost at a relatively wide range of the order of ±20%. In this context, the associated interconnection costs for the baseline Case (or reference Case) are presented in Table III.

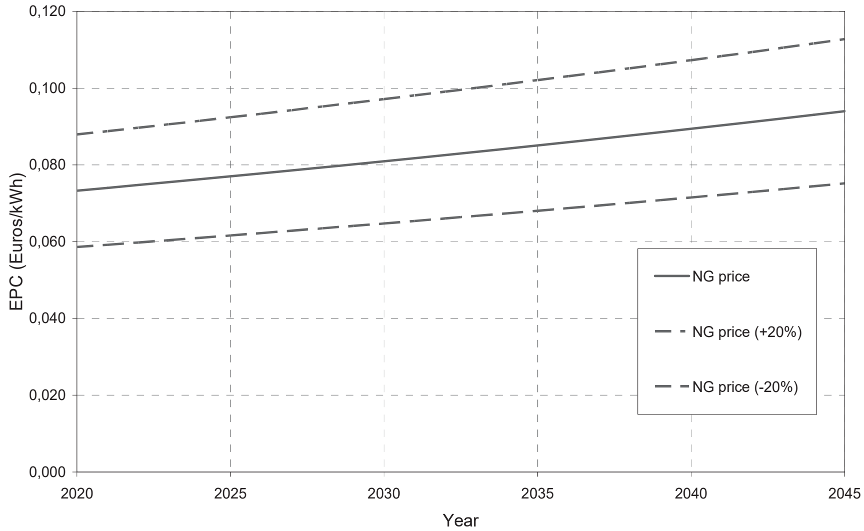

Fig. 4 Projected evolution in EPC for NG (without the environmental impact)

TABLE III
COSTS OF INTERCONNECTION EQUIPMENT

Description	Cost
1. Submarine cables (Pair of unipolar cables DC)	
150MW	0.37 m€/km
250MW	0.42 m€/km
350MW	0.50 m€/km
550MW	0.60 m€/km
750MW	0.80 m€/km
1,000MW	1 m€/km
2. Substations with transformers (AC/DC or DC/AC)	
150MW	40 m€
250MW	45 m€
350MW	50 m€
550MW	60 m€
750MW	75 m€
1,000MW	90 m€
3. Underground cables	
150kV-HVDC	0.50 m€/km
4. Overhead cables	
DC	0.20 m€/km

At this point, it should be mentioned that the interconnection points between the island and the mainland, the route and the length of the new electrical network (underwater, underground and overground) and the technical characteristics of the technologies involved (e.g. number/ positions of substations, type of submarine cables, etc.) are determined based on economic criteria and technical conditions of the already existing literature [4], [5], [14]. On the other hand, the suitable capacity of the submarine cables serves as a parameter for investigation, which directly depends on the required (maximum) amount of electricity transported from the island to the mainland grid and vice versa (see (5) and (6)). Thus, according to the above, it is assumed that the interconnection incorporates underwater HVDC cable technology, which is considered the most appropriate method of transporting large quantities of energy over long distances [22], [23]. Furthermore, the total length of the interconnection is estimated equal to 288km [14], connecting at first Lesbos island with Euboea (213km) and then Euboea with Larymna (75km), which belongs to the mainland part of the country (Fig. 1). The total length of the submarine, underground and overhead lines is considered 233km, 50.4km and 4.6km, respectively.

V. Sensitivity Analysis

As resulting from the above, the analysis of the techno-economic behavior of the two main scenarios currently investigated is based on a substantial number of variables and assumptions (e.g. initial cost of interconnection, fuel costs, load demand variation, etc.). Examination of the impact of changing the selected value of each examined variable, while keeping constant other variables, would generate a large number of results that would be difficult to cope with and interpret in a concise manner. With the aim to overcome such problems, an extensive sensitivity analysis is performed with respect to possible deviations in the values of the most uncertain variables in order to identify the worst (pessimistic-Pe), reference/baseline (most likely- Ba) and best (optimistic - Op) output results. Note that the selected value of variables used in the baseline Case corresponds to those data found in bibliography and in technical reports [4], [5], [8], [17], [19], [21]. More specifically, the main input variables in the sensitivity analysis along with the respective variation in reference values are:

- *Scenario 1-Baseline (S1-Ba)* (reference Case): wind power upper participation limit (λ)→ 30%, oil price→ 0% variation in reference value [17], [19], load demand→ 0% variation in reference value (Fig. 2)
- *Scenario 1-Optimistic (S1-Op):* λ→ 40%, oil price→ -20% variation in reference value, load demand→ -15% variation in reference value (a condition which although reduces WE absorption rates, at the same time also reduces the requirements for thermal capacity, resulting finally in lower total cost for electricity generation)
- *Scenario 1-Pessimistic (S1-Pe):* λ→ 20%, oil price→ +20% variation in reference value, load demand→ +15% variation in reference value (a condition which although increases WE absorption rates, at the same time also increases the requirements for thermal capacity, resulting finally in higher total cost for electricity generation)
- *Scenario 2-Baseline (S2-Ba)* (reference Case): mainland's EPC→ 0% variation in reference value [4], [8], [21], capital cost of interconnection→ 0% variation in reference value (Table III) [5], load demand→ 0% variation in reference value (Fig. 2)
- *Scenario 2-Optimistic (S2-Op)*: mainland's EPC→ -20% variation in reference value, capital cost of interconnection→ -20% variation in reference value, load demand→ -15% variation in reference value
- *Scenario 2-Pessimistic (S2-Pe)*: mainland's EPC→ +20% variation in reference value, capital cost of interconnection→ +20% variation in reference value, load demand→ +15% variation in reference value

VI. Energy Model Results

This section summarizes the main results after the application of the analysis presented in Section III during the years 2020-2045 for the two investigated scenarios, i.e. autonomous development of the island (S1) against the interconnection with the mainland grid (S2).

Fig. 5 shows the average (annual) Capacity Factor (CF_w^a) (i.e. the ratio of the annual WE, which is absorbed by the grid, to the WFs potential output if it were possible to operate at full nameplate capacity continuously over the same time period) during the lifetime of the project which varies between 13 and 37% in case of autonomous development (S1). The highest rates are noticed in the optimistic Case mainly due to the selected value of the wind power upper participation limit (40%); however, no significant differences arise in relation to the other two Cases. Furthermore, in all Cases a gradual reduction of CF_w^a may be observed when increasing wind power installations because the local grid reaches its "saturation point", thus leading to remarkable WE rejection. To this end, Fig. 5 also shows (right y-axis) the average (annual) expected WE rejection during the examined time period, with the highest amounts corresponding to the pessimistic Case due to the lowest value of λ (20%).

Following, Fig. 6 presents the overall electricity mix for S1 from the beginning of the project until the end of its life, as well as the average (annual) share of WE penetration to the electricity consumption of the island, which hardly approaches 25%. It is worth mentioning that the increase of WE contribution to the island's demand is more obvious in lower WF capacities (e.g. <41MW); further increase in nameplate capacity does not entail the same contribution increase rates due to local grid's technical limitations.

Accordingly, Fig. 7 presents the overall electricity mix for S2 from the beginning of the project until the end of its life in relation to WF installed capacity for each investigated Case. Also from Fig. 7 one may obtain the average (annual) share of WE penetration to the electricity consumption of the island, which ranges between 8 and 70%. As far as the overall contribution of natural gas (energy from mainland) in total electricity generation is concerned, its share ranges between 24% (2,473GWh) and 86% (12,122GWh). It is worth mentioning that CF_w^a equals to the quite high value of about 37% (corresponding to the wind speed time-series data used in the simulations) in all examined Cases and WF capacities. As there is no WE rejection, any WE surplus is forwarded to the mainland grid, thus increasing CF_w^a. On the contrary, in Scenario 1 it was found between 13% and 37% depending on the WFs capacity and on the upper wind power participation limit (Fig. 5).

Comparing the overall mix for electricity generation (Fig. 7) of all Cases of Scenario S2 (Op, Ba, Pe) with the respective results of Scenario S1 (Fig. 6) it becomes clear that the project of interconnection −in combination with the absence of technical constrains in wind power absorption− result to remarkable WE contribution increase into the island's energy balance, i.e. from the maximum limit of almost 25% (S1-Op) to the share of 70% (S2-Op). By taking a closer look at Figs. 6 and 7 and at the specific (and common) WF capacity of 68MW between S1 and S2 it may be seen that WE contribution into the island's energy balance is considerably higher in S2 compared to S1 for the same WF capacity rating.

Specifically, in S2 the wind share ranges from 38% (S2-Pe) to 45% (S2-Op), while in S1 from 14% (S1-Pe) to 23% (S1-Op).

VII. Economic Model Results

Before proceeding to the economic model results it should be mentioned that the time horizon of the financial analysis is considered as 25 years, from 2020 to 2045 (j=5 to j=30). It is assumed that the installation of the project will have been completed in 2020 (see also Table I) and that it will start to operate on 1/1/2021. Moreover, it is considered that the project owner of the new WFs (S1 and S2), the IC (S2) is the same.

The Levelized Cost of Energy for both scenarios is presented in Figs. 8 and 9. It should be noted, that the pessimistic and optimistic Cases represent the maximum (worst) and minimum (best) cost-related solutions, respectively.

As far as the LCOE in S1 is concerned it is found between 160 (S1-Op) and 220€/MWh (S1-Pe), Fig. 8. In the baseline Case the cost ranges from 185 to 195€/MWh, depending on wind capacity. As it may be seen, the common base for the three Cases (Op, Ba, Pe) is that the increase in WF capacity initially results in a slight decrease of the production cost, which is then smoothed and the LCOE seem to rise again. In other words, the benefit from increasing the WF nameplate capacity is greater at first, while further capacity increase does not entail equal cost reduction due to the inability of the local grid to absorb larger amounts of WE production. In any case however, it is noted that any changes caused by WF capacity increase are almost imperceptible and substantial independence from oil imports may not be achieved.

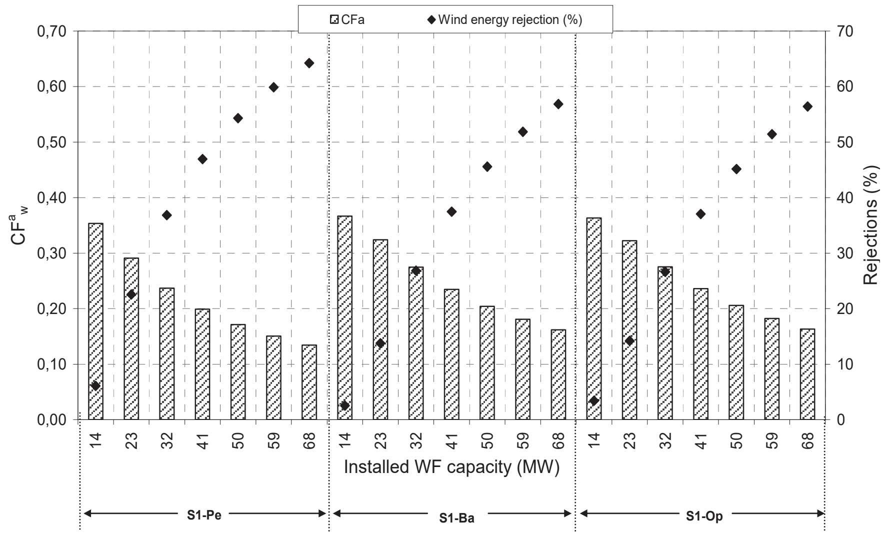

Fig. 5 Average annual CF_w^a and WE rejection percentage in relation to WF installed capacity for the three examined Cases (Scenario 1)

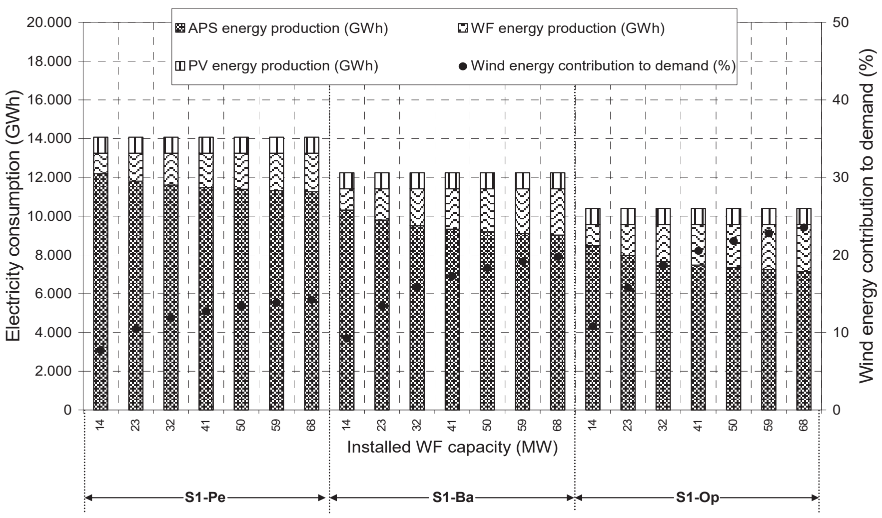

Fig. 6 Overall electricity mix and average (annual) share of WE penetration to the electricity consumption of the island in relation to WF installed capacity for the three examined Cases (Scenario 1)

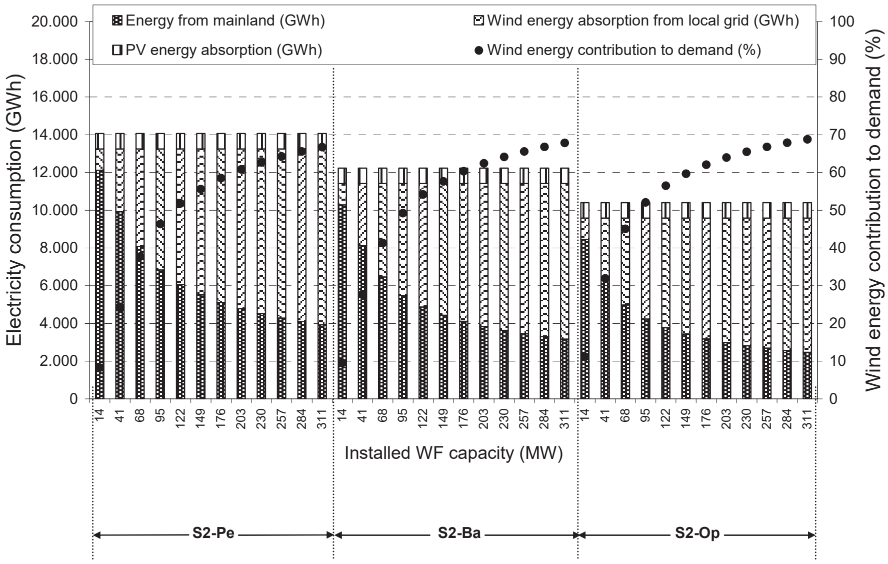

Fig. 7 Overall electricity mix and average (annual) share of WE penetration to the electricity consumption of the island in relation to WF installed capacity for the three examined Cases (Scenario 2)

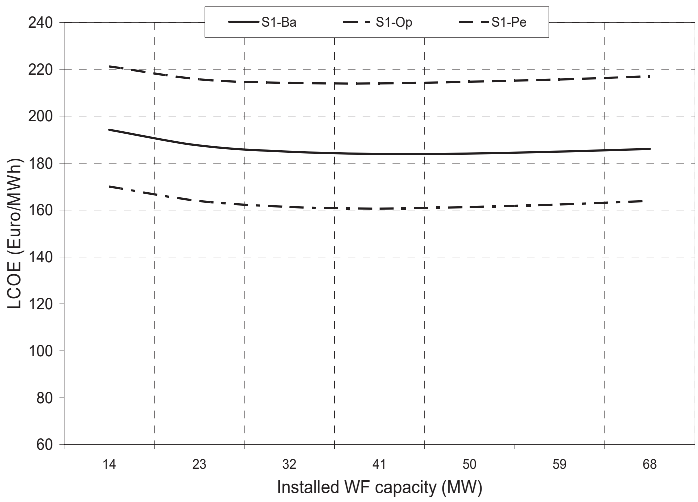

Fig. 8 LCOE during the lifetime of the investment in relation to WF installed capacity for the three examined Cases (Scenario 1)

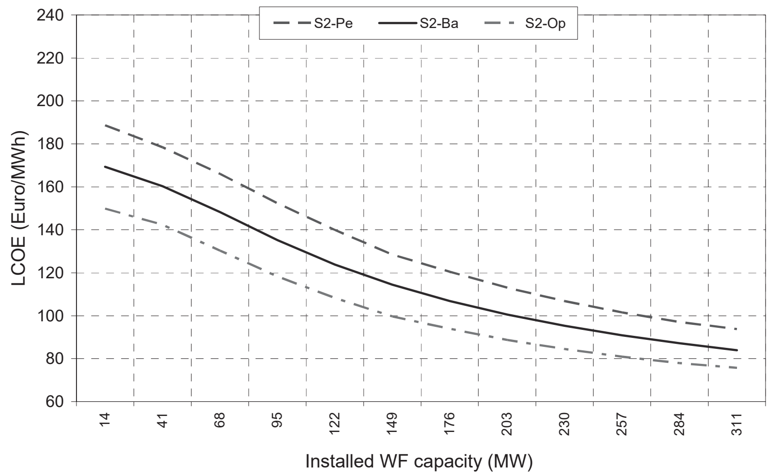

Fig. 9 LCOE during the lifetime of the investment in relation to WF installed capacity for the three examined Cases (Scenario 2)

Figs. 10 and 11 depict the breakdown of total costs (in present values) from the beginning of the project until the end of its life cycle for the two scenarios. As it may be seen in S1 (Fig. 10), total cost is formed by the initial cost of the new power units, the cost of purchasing energy from (existing or new) RES-based plants, operation and maintenance expenses of the APS (fuel, maintenance, CO_2 costs) and total operation and maintenance costs of the new WFs. It should be noted that the arising differences among the examined Cases (Op, Ba, Pe) seem to be significant. The pessimistic Case constitutes the most expensive solution, the results of which are almost double the respective results of the optimistic one. Among the different cases of rated power, it can be seen that the increase in the WFs capacity (capital cost for new WFs) does not cause significant change in the total cost as this increase is compensated by the decrease in operating expenses of the APS mainly due to the reduction in fossil fuel consumption. On the other hand, total cost in S2 (Fig. 11) includes the investment and operating costs of new wind power systems, the capital cost of interconnection, the cost of energy supply from the mainland grid and the cost of purchasing energy from (existing or new) RES-based plants. Similar to the scenario of autonomous development, the differences arising among the three alternative Cases are noteworthy. The pessimistic Case (S2-Pe) comprises the most expensive solution as the demand is considered 15% higher than S2-Ba, a condition which increases the energy requirements from the mainland grid and the power capacity of the interconnection. Moreover, in the pessimistic Case, an increase of 20% compared to S2-Ba is also taken into account for the total EPC on the mainland, as well as for the interconnection investment cost. The remaining costs (i.e. capital and operational costs for new WFs, renewable energy payments) that form total lifetime expenses are the same in all three Cases (baseline, optimistic, pessimistic).

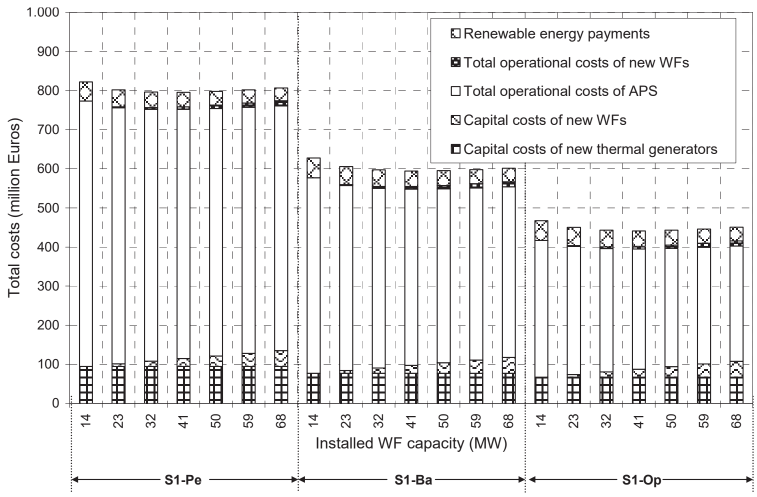

Fig. 10 Total costs breakdown in relation to WF installed capacity for the three examined Cases (Scenario 1) (in present values)

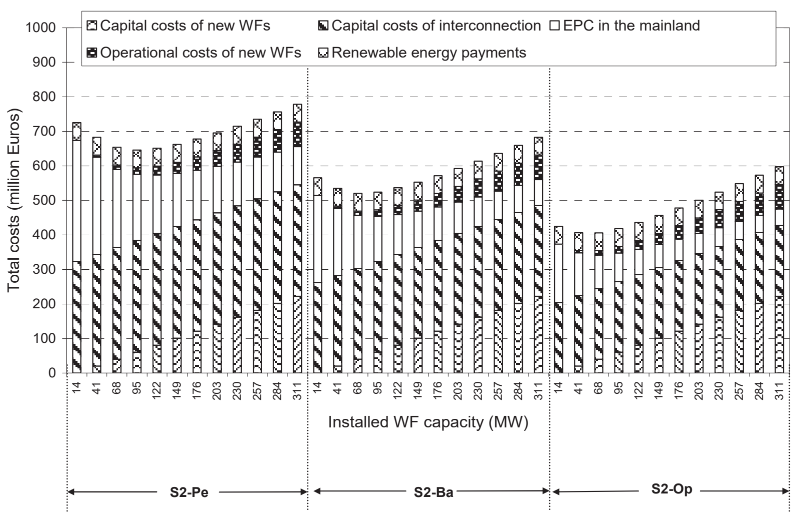

Fig. 11 Total costs breakdown in relation to WF installed capacity for the three examined Cases (Scenario 2) (in present values)

As far as total power capacity of submarine cables is concerned, as already mentioned, it is determined on the basis of (5) and (6) and by assuming -as an extreme (most expensive) case- the installation of two pairs of unipolar cables (of the same rated power), so as to ensure power transmission between the mainland and the island equal to 100% of the required capacity in case of failure of the one connector. In this respect, Table IV includes total interconnection power capacity for the three examined Cases (Op-Ba-Pe) in Scenario 2.

TABLE IV
MAIN CHARACTERISTICS OF THE INTERCONNECTION PROJECT

Case	Total capacity of interconnection (MW)	Forecasted peak load demand during 2020-2045 (MW)	Installed WF capacity (MW)
S2-Op	2x129	124	
S2-Ba	2x152	146	14-311
S2-Pe	2x175	168	

VIII. CONCLUSIONS

In the present study, the techno-economic viability of high WE share at local (island) level was investigated by performing comparative analysis of alternative “development scenarios” for future electricity generation. Two main scenarios were investigated, i.e. the first (S1), which was based on the autonomous development of Lesbos island to keep using oil products as the main source for electricity generation and the second (S2), having as a main feature, the interconnection of the island with the mainland grid and the complete removal of local thermal generators. The economic feasibility of the above solutions was investigated by determining the LCOE over a 25-year evaluation period, while also including a sensitivity analysis on the respective worst/reference/best Cases.

According to the present preliminary analysis results concerning the two investigated scenarios it may be stated that the development of interconnection between Lesbos island and the mainland part of the country along with the high WE use is the optimum solution, succeeding in a significant reduction in the objective function of the present study, the LCOE. More specifically, as far as Scenario 1 is concerned, even if a possible increase in WE applications would take place, WE contribution to the island’s annual load demand would hardly approach 25%, due to the associated technical limitations and dynamic constraints. At the same time, the LCOE would remain quite high, close to current levels, despite the WF installed capacity. On the other hand, according to the results, the island’s interconnection is worthy of further investigation, as it presents considerable economic interest and may be seen as a great challenge for meeting part of the island’s future electrification needs. The role of WE in that direction is vital as its contribution increase offers remarkable cost savings, due mainly to the reduction of the energy dependence of the island on oil imports. Furthermore, one should not disregard the possibility that aside from the cost savings from an investor’s (system operator) perspective, the WE amounts that cannot be absorbed in the island (during low demand periods) and are considered to be “pumped” to the mainland through the submarine cables, will contribute to the sustainable development of the overall Greek power sector.

Finally, it should be mentioned that future research on the island’s interconnection should include a dynamic stability analysis of the power system, especially when studying high wind power penetration levels, in order to ensure reliability of the system and enable a cost effective integration of the whole project. In addition, future research should weigh the resulting economic benefits of high WE use against issues such as social acceptance or other environmental and spatial planning concerns for new WFs installation.

APPENDIX

In order to determine the maximum WE contribution to the island’s energy balance and examine the possibility of installing additional wind power, the annual hourly mean power production time-series is modelled according to the existing thermal power station characteristics. For this purpose, the technical minima, Specific Fuel Consumption (SFC) and production schedule dispatch order of the thermal power units are all taken into account. More specifically, the following "sub-steps" may be followed:

1. Determination of the units’ production schedule dispatch order, based on the fuel type consumed by each unit, achieving the minimum electricity production cost [2], [9], [24].
2. Calculation of the minimum and the maximum electric power generation of the thermal engines and the determination of "z" operational points of the conventional power station according to the thermal units’ minimum output power (technical minima), their production schedule dispatch order and their SFC.
3. Inclusion of a monthly maintenance plan of the thermal power units, excluding the months where the demand is very high (i.e. summer months). The units that are going to operate during the selected year on an hourly basis are determined by finding the minimum number of thermal units that must operate in order to satisfy the mean-hourly power demand. Subsequently, it is assumed that the sum of units’ technical minima is the power which must be at least provided in order to cover the demand.
4. Estimation of the instantaneous maximum wind power penetration in the local grid on the basis of local electrical system constraints [25]. At this stage, one may examine the effect of different wind power upper participation limits (e.g. λ= 0.20, 0.30, 0.40) on the WE contribution. In general, the maximum average-hourly wind power penetration into a remote island network is equal to the difference between load demand and the ‘on duty” thermal units’ minimum output power, bearing also in mind any power generation from other sources which have priority according to the specified dispatch order into the production schedule [26].
5. Estimation of the maximum mean hourly wind power absorbance of both existing and future wind farms by the Electricity Generation System (EGS) of the island and the

corresponding curtailments [24]. If the sum of power generation from WFs and from the other 'on duty' sources is greater than the load demand, the difference concerns the wind power output which cannot be absorbed by the local grid and should be rejected. At this point, the expected wind power production is calculated with the use of specific wind turbine power curves and analytical real wind speed measurements referred to the hub height of the turbines and being representative of the average wind conditions met in the area of interest.

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