

Optimal carbon-electricity trade-offs through the virtual power plant concept

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Abstract

To ameliorate the increased challenges relating to renewable energy sources set by European Union targets for the 2020, 2030 and 2050 paradigms, in this work a carbon-electricity model is proposed by making use of a virtual power plant mechanism. The radical configuration is arranged for the islanded power system of Cyprus, by making use of internal combustion engines, steam generators and domestic wind, photovoltaic and biomass units. Using an algorithm relied on mixed-integer linear programming, clean resources integration can be enhanced in a cost-effective manner in terms of total production and emission cost. Based on actual data with respect to load demand and power generation, the proposed concept offers optimal carbon-electricity trade-offs in the presence of storage. Specifically, the annual amount of carbon-dioxide emissions decreases by almost 74,000tn increasing the renewables share from 25.73 to 64.33% at the virtual power plant level. The released emissions are completely eliminated by making use of hydrogen derived by renewable hydrogen pathways in 100% renewable systems. The incomes of the assessed scenarios towards 2050 paradigm of de-carbonization are 81.360 M€ and 112.148 M€ for the respective life-cycle analysis without and with regenerative fuel-cell storage facility. As for future directions to research, a more comprehensive carbon-trading system is indicated to consolidate other Greenhouse gas emissions, including carbon oxide (CO), methane (CH₄), nitrogen dioxide (NO₂) and sulfur dioxide (SO₂).

Keywords Renewable energy sources · Virtual power plant · Electricity storage · Carbon trading system · Hydrogen pathway

1 Introduction

In the context of global warming and consequent climate change, the utilization of renewable energy sources (RES) is becoming a vital necessity [1]. Due to environmental concerns with respect to the pollutants released during fossil-fuels exploitation, the research interest is focusing on exploring clean and efficient resources across the globe. Several efforts have already been made in determining the potential of resources ranging from solar, wind, biomass and hydro to emerging technologies related to geothermal, wave, tidal and ocean thermal alternatives [2].

In the early 2000s, the need to include RES in the energy mixture came to light and most countries relied on providing incentives to producers of various scales. The concept of “*paying at the cost of avoided conventional generation*” dominated electricity markets, leading to a continuous increase of RES system installations. The energy scene has changed drastically from the very first decade. The implementation of European Union (EU) directive 20-20-20

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resulted in numerous licenced participants, which in turn have led in some critical challenges. Power grid expansions, transmission and distribution equipment upgrades, specialized automation and protection systems, appropriate telecommunication protocols and sophisticated supervisory control and data acquisition (SCADA) devices came to adorn the power system networks, showing a significant increase in cost across all electricity activities. Hence, in order to achieve the adopted targets, the EU member states turned into radically different generational and consumer models including net-metering, net-billing, demand response and demand-side management strategies.

Alongside, each governmental enforcement against carbon emissions (including carbon capture and storage at the conventional generation side) opposes the attempts to increase energy efficiency. Consequently, in their effort to further increase the renewable share and transform the conventional consumers to active prosumers, the EU countries developed proper platforms to represent the ancillary services, namely frequency control, voltage regulation and black start provision. In the light of the second decade of 21st century, several studies performed to investigate the feasibility of RES for power generation under the scenarios of heating and transport electrification. Most of them concluded that conventional generators can adjust production to demand only up to a certain level of RES penetration. According to preliminary data sets, in 2020, a 31% reduction in greenhouse gas (GHG) emissions achieved by 21 (of 27) EU members, compared to 1990's values [3]. To comply with their legal objectives, Bulgaria, Cyprus, Finland, Germany, Ireland and Malta need to use flexibilities, such as buying emission quotas from other EU countries. At higher RES injections, the uncertainty and intermittency cannot be addressed properly and conventional systems would occur inadequate. Based on these findings, the scientific research around energy security re-directed towards innovative configurations and smart grid operations that involve resources decentralization, energy storage, microgrid formations, international electricity interconnections and virtual power plant (VPP) mechanisms [4].

Looking towards the new target requirements of 2030 and 2050, which accounts for even more GHG reductions in the order of 55% and 100%, respectively, each proposed solution must be analysed in depth based on realistic actions and real-world scenarios. These may include achievable RES penetration levels in combination with real power demand and carbon-neutral and/or carbon-free carriers to replace fossil fuels. In addition, the feasibility of electricity storage systems (ESS) must be subjected into life-cycle cost analyses in order to examine their overall contribution in sustainable development, relying on realistic cost metrics and actual energy requirements. Finally, a diversity of case-studies has to be conducted to fairly compare and result in the best-fit combination which would reach the imposed goals, while retaining the security of energy supply.

In this work, the feasibility of a VPP for the case of the energy system of Cyprus is examined. Considering the isolated power system of the island, neither international interconnections nor microgrid formations are considered. On the contrary, the existed distributed energy resources (DERs), such as solar, wind and biomass, are examined by making use of actual electricity data. Under the constraints of EU directive, the assessed scenarios must account for considerable increases in RES generation in the presence of storage and fuels derived from renewable pathways towards carbon-neutral electricity networks. To strengthen the benefit list of RES contribution in total generation, optimal carbon-electricity trade-offs between the proposed VPP and national grid have to take place. For this purpose, there is a requirement for developing a model able to capture the hourly power transactions and compare the financial income using realistic emission, ESS and hydrogen metrics.

The cooperation of electric vehicles (EVs) and renewable generation is addressed with the aid of VPP in [5]. The DERs in this hybrid system are optimally aggregated and self-scheduled in day-ahead electricity (energy and reserve) market, considering price, wind generation and EVs uncertainties. From the economic point of view, the VPP occurs more active in day-ahead energy market, with profit from trading energy and providing it for EVs. The performance and consumer satisfaction of a VPP with the exclusive role of EV charging is assessed in [6], where a bi-level tariff scheme is proposed to control the energy exchanges and support the distribution system operators. The techno-economic aspect of a VPP consisted of battery energy storage systems (BESS) is analysed in [7], in view of the Malaysian target of 2025 for 20% RES in energy mix. The analysis concluded that in small scales, the feasibility of BESS is ensured only in a VPP concept for charging/discharging and participation in ancillary-services market. In [8], the optimal scheduling is obtained by a robust-stochastic approach that takes into account the uncertainties of the zero-carbon multi-energy systems via Latin Hypercube Sampling method. The authors in [9] developed a novel method of profit allocation for multiple DERs that co-exist in a combined heat and power-virtual power plant (CHP-VPP). The proposed concept enables the coordinated dispatching of heat and power, leading to optimal profit allocation based on an improved Shapley value method.

Based on the existing literature, most studies are focused on the optimal scheduling of the proposed VPPs as generators. A different approach presented in [10], aims at optimizing the operation of grid components (wind turbines, ESS, PVs

and car charging stations) to minimize consumption of the electric energy from the external supply network. The authors indicated that the VPP may be also used as a data acquisition tool for PV energy forecasting. The work found in [11] is focused on the operation of the storage unit within a VPP. Its operation optimization was addressed by the application of particle swarm optimization (PSO) algorithm. In this study, the correct choice of a control variant, based on the energy flow measurements, to settle the charging or discharging ratio of the storage unit is taken into consideration. Appino et al. [12] and Shinde et al. [13] constitute two representative studies for the research work carried out recently. Appino et al. [12] presents a model predictive control for integrated electricity-hydrogen VPP in real-time markets, whereas Shinde et al. [13] proposes a multi-stage stochastic programming approach to model the trading of a VPP comprising thermal, wind and hydro power plants, in continuous intraday electricity markets. According to the extensive literature, there has not yet been a comprehensive analysis of a VPP that takes into account the bi-directional power flow to optimally determine the electricity-emission trade-offs of a system consisted of different DERs and fluctuating load demand.

The alternative studies carried out, consolidating into their formulation the intermittent DERs and ESS charging/discharging, mainly rely on empirical, heuristic, or stochastic mechanisms for uncertainty-set development and decision on optimizable variables. This way, the exact transactions between consecutive solutions cannot be traced accurately, leading to near-optimal decisions with respect to VPP electricity trades. This work is differentiated in terms of both the scenario development and optimization solution. Utilizing actual data regarding the RES contribution, four scenarios are developed to account for the forthcoming EU targets. Then, the optimization task is formulated as a mathematical, mixed-integer linear programming problem, in order to extract traceable, global solutions considering the generational and emission costs. In addition, the term of storage is properly modeled, considering the round-trip realistic losses and distinguishing the power-related and energy-related costs, based on the most realistic metrics found in the literature.

The rest of the paper is organized as follows. In Sect. 2, emphasis is given on the VPP model development to adequately formulate the generator model, the emission costs and electricity storage. In Sect. 3, the test case system is presented along with the objective of the proposed VPP. The extensive experimental evaluations and obtained results are analysed and discussed in Sect. 4. Finally, the conclusions are drawn in Sect. 5.

2 Model formulation

To specify the operation objective of the VPP, all of its comprising components must be formulated in detail. The proposed VPP consists of generation, load and storage. The generation is distinguished into thermal and renewable, while the storage acts as load during charging and generator at discharging periods. Unlike hydrocarbon fuels, renewable sources do not release any emissions during the electricity production procedures. Relating to hydrogen, it can be produced from any primary source and used as the energy carrier either for direct combustion or in a fuel cell (FC), producing water as the only byproduct [14]. All emissions are avoided only when hydrogen arises from renewable resources via non-reforming and water splitting procedures.

At the point of connection between the VPP and national grid, the power balance equation is expressed as follows:

$$P_{Grid}^t = \sum_{i=1}^N P_i^t + P_{RES}^t + P_{dis}^t - P_{ch}^t - P_{load}^t \quad (1)$$

During the time interval t , the power transactions between the national grid and VPP are represented by P_{Grid}^t . P_{RES}^t forms the aggregated power from renewable energy sources, while the power of the storage medium is defined by P_{ch}^t and P_{dis}^t during the charging and discharging procedures, respectively. Finally, P_i^t is used to determine the power output of the i th (of total N) conventional generator.

Based on (1), the grid power is positive when energy is drawn from the VPP and becomes negative if electricity is injected into the VPP. Apart from electricity, emission exchanges take place depending on the regional electricity needs and domestic renewable contribution. This way, the mathematical objective is formulated in Eq. (2) so as to minimize both the total generation and emission cost, subject to the unit status S_i^t , the power output of each generator and its start-up cost [15].

$$f = \min_{i,t} \{ F(P_i^t | S_i^t) + E(P_i^t | S_i^t) \} \quad (2)$$

2.1 The generator model

Two models are used to quantify the generation cost from conventional fuels and renewable energy resources. The conventional, thermal generation is described by the cost function of Eq. (3), where a_i , b_i and c_i are the cost coefficients derived from the fuel-specific cost C_f and heat-rate quadratic curve H_i of the generator i [16, 17].

$$F(P_i^t | S_i^t) = \sum_{i=1}^T \sum_{i=1}^N \left\{ S_i^t \left[\left(a_i P_i^{t2} + b_i P_i^t + c_i \right) + (1 - S_i^{t-1}) S U_i \right] \right\} \tag{3}$$

SU_i corresponds to the start-up cost and is evaluated by taking use the fuel consumption (e.g. measured in kg) and the fuel specific cost (per kg of fuel). The change of state of each generator strictly depends on three main parameters. The first refers to the maximum number of actions that can be performed in a specific power plant. This is reflected as the maximum number of simultaneous generator start-ups or shutdowns per plant. The rest of parameters express the minimum duration that must be elapsed before state-changes, considering the respective minimum-up time and minimum-down time for each independent unit. Relating to the power-output level, the restrictions account for the capacity and ramping capabilities considering the minimum and maximum limits together with the ramp-up and ramp-down constraints. On the other hand, the evaluation of renewable electricity cost is achieved based on constant rates for purchase f_{RES}^- or sale f_{RES}^+ prices and the aggregated power from renewables. This expression equation is written as:

$$F_{RES}(t) = f_{RES} P_{RES}^t \tag{4}$$

where the aggregated RES are defined as $P_{RES}^t = P_{PV}^t + P_{wind}^t + P_{bio}^t$, accounting for solar PV (P_{PV}^t), wind (P_{wind}^t) and biomass (P_{bio}^t) power.

2.2 The emission-cost model

A second model is needed to identify and estimate the emitted pollutants. To retrieve the heat-rate coefficients, the cost coefficients are divided by C_f . The resulted coefficients can be then multiplied by the emission specific cost e_f which exclusively depends on the fuel type (f) used and CO_2 penalty cost π_{CO_2} . This way, two further expressions can be defined to facilitate in emission cost estimation depending on the available cost metrics. According to the fuel, the amount of CO_2 released is represented by C_r . Hence, the new, emission coefficients are estimated as shown below.

$$\begin{cases} a'_i = \pi_{CO_2} \frac{a_i}{C_f NCV_i} C_r \\ b'_i = \pi_{CO_2} \frac{b_i}{C_f NCV_i} C_r \\ c'_i = \pi_{CO_2} \frac{c_i}{C_f NCV_i} C_r \end{cases} \tag{5}$$

To this end, the quadratic emission-cost curve can be described by Eq. (6) (or Eq. 7), as a function of the power output of each generating unit.

$$E(P_i^t) = a'_i P_i^{t2} + b'_i P_i^t + c'_i \tag{6}$$

$$E(P_i^t) = e_f \left[\left(\frac{a_i}{C_f} \right) P_i^{t2} + \left(\frac{b_i}{C_f} \right) P_i^t + \left(\frac{c_i}{C_f} \right) \right] \tag{7}$$

To also include the CO_2 emissions during start-up, the total emission-cost function is calculated as:

$$E(P_i^t | S_i^t) = \sum_{i=1}^T \sum_{i=1}^N \left\{ S_i^t \left[\left(a'_i P_i^{t2} + b'_i P_i^t + c'_i \right) + (1 - S_i^{t-1}) S U E_i \right] \right\} \tag{8}$$

Given the state condition S_i^t , the emission cost of each operating generator follows the quadratic function proportionally and depends on the power output. As a result, the power output of each conventional generator forms an optimizable variable, which can lead the scalar value of total cost to a minimum, subject to a number of imposed constraints in the allowable domain. The start-up emission cost SUE_i for each generator i , can be estimated by Eq. (9).

$$SUE_i = \pi_{CO_2} \frac{SU_i}{C_f} C_r \quad (9)$$

2.3 The storage model

In order to evaluate and compare electricity storage technologies with different cost structures, the proposed model distinguishes the power-related and capacity-related costs. The capacity-related costs accommodate the initial cost of the storage medium (C_{ESM}) and all variable expenses with respect to operation and maintenance ($C_{vO\&M}$). The costs associated with power costs include all capital expenses related to the balance of the plant (C_{BoP}) and the power conditioning system (C_{PCS}), as well as the fixed operation and maintenance costs ($C_{fO\&M}$) [18, 19].

Denoting the rated power of the ESS with P_{rated} and the ESS capacity with E_{cap} , the initial capital cost (ICC_k) of the storage-system candidate k is obtained by Eq. (10). This formula can be re-written (Eq. 11) to include the storage losses, considering the round-trip efficiency (η_k), the depth of discharge (DoD_k) and the self-discharge rate (SDR_k) which in turns depends on the maximum storage duration t_s .

$$ICC_k = P_{rated} (C_{BoP}^k + C_{PCS}^k) + E_{cap} C_{ESM}^k \quad (10)$$

$$ICC_k = P_{rated} (C_{BoP}^k + C_{PCS}^k) + \frac{E_{cap} (1 + SDR_k)^{t_s}}{\eta_k DoD_k} C_{ESM}^k \quad (11)$$

Equation (12) shows how the respective annual O&M expense is obtained, based on the total annual electricity stored E_s :

$$C_{O\&M}^k = P_{rated} C_{fO\&M}^k + E_s C_{vO\&M}^k \quad (12)$$

$$E_s = \sum_{t=1}^{8760} P_{ch}^t \quad (13)$$

Finally, the life-cycle cost of storage ($LCOS$) during a L -year assessment, is estimated as shown below, considering a discount rate expressed by i_r [20].

$$LCOS_k = -ICC_k + \sum_{l=1}^L \frac{C_{O\&M}^k(l)}{(1 + i_r)^l} \quad (14)$$

3 Test case system and VPP

Identifying the critical need to increase RES integration towards the 2030s and 2050s targets, the proposed VPP accommodates both renewable and conventional generation, as well as electric load, and explores the potential of electricity storage under different scenarios. Between the six EU countries that must buy emission quotas from other member states, Cyprus represents the most challenging system due to its islanded, non-interconnected and relatively small-scale network. For this reason, the isolated power system of the island of Cyprus is selected as a reference test-case explained as follows.

In terms of administrative centres of the electricity sector, the district capitals of the entire Republic of Cyprus in population order are: Nicosia (Capital), Limassol, Larnaca and Paphos. The conventional generation of the island relies on 21 generating units, distributed in three main power plants as depicted in Fig. 1. The domestic resources utilized for power generation regards solar PVs, wind parks and biomass plants. The generational distribution at the main electricity centers is shown in Fig. 2, while the generational profile of Cyprus in relation to the selected administrative center of the district of Larnaca is listed in Table 1.

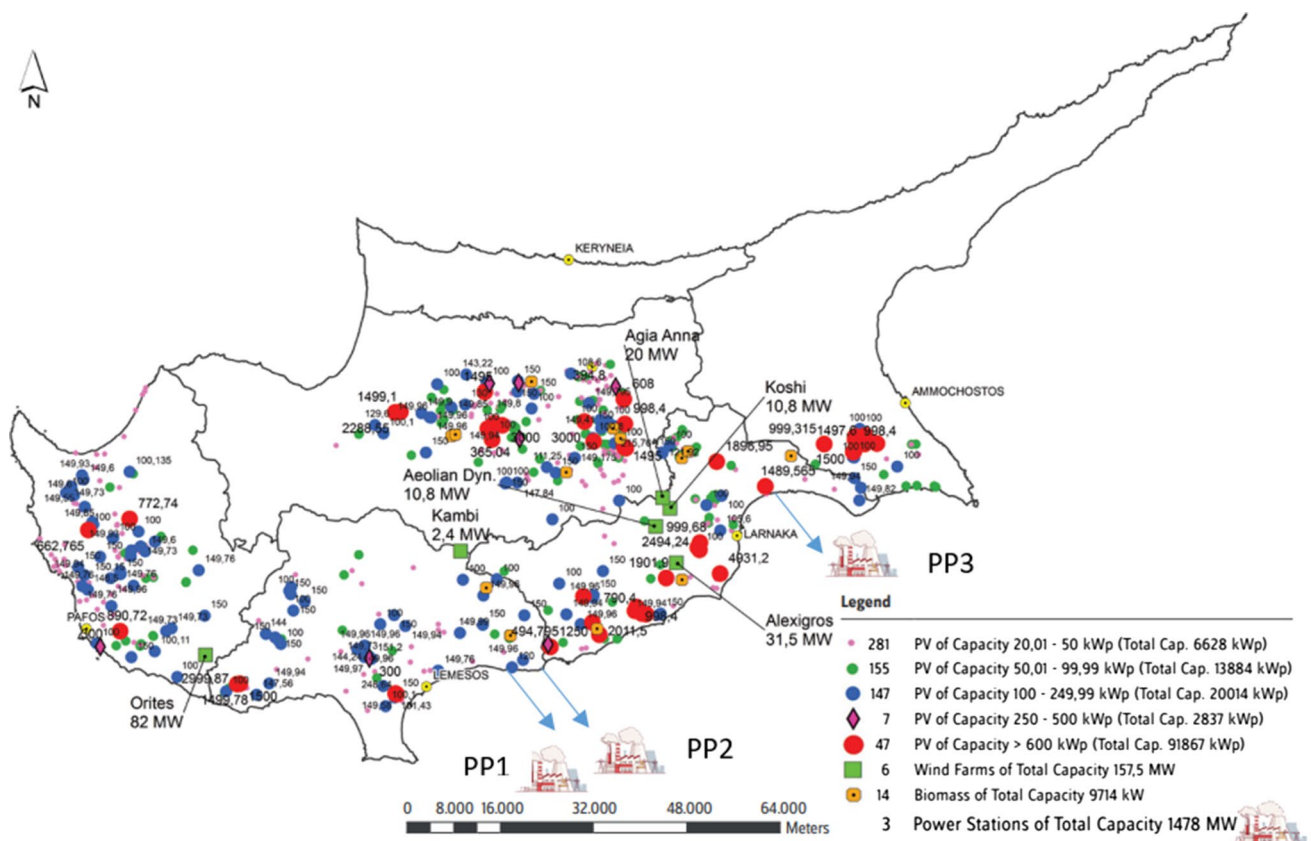


Fig. 1 Geographical distribution of renewable and conventional generation until 2021

Fig. 2 Generational distribution at the main electricity centers [21]

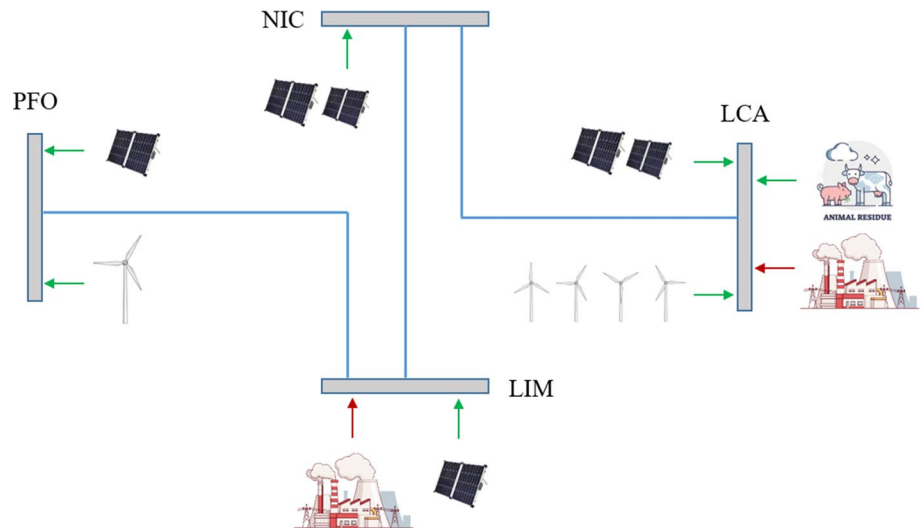


Table 2 lists all available generating systems per plant. Six steam units and six internal combustion engines (ICE) are at the VPP’s disposal. To gain a broader overview of the proposed VPP operation, Fig. 3 can be used to provide its strategic operation during excess and deficits of generation. Specifically, once the domestic load is satisfied, power injections to the national grid consist of prioritized renewable electricity from wind, lowering conventional generation until the minimum capacity of one must-run steam generating unit. Accounting for 1.45% and 4.03% losses in transmission and distribution, respectively, it is therefore assumed that, since wind farms are connected to transmission network and conventional generation is controlled, the energy transmitted to the national grid is composed of wind generation until its exhaustion followed by conventional electricity. Otherwise, excess electricity from PVs could be transmitted to the

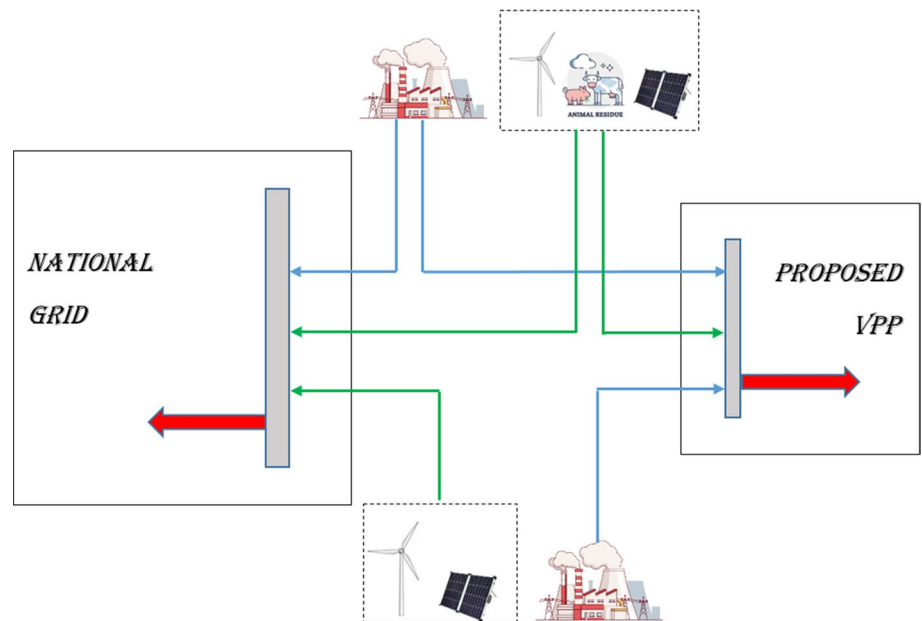
Table 1 Generational profile of the island of Cyprus in relation to the selected administrative district

	Cyprus	Larnaca district
Population (habitants)	1,346,000	72,000
Latitude	35° 5' 42.6912" N	34° 55' 22.48" N
Longitude	33° 12' 12.3480" E	33° 37' 23.88" E
Morphology	Coastal perimeter, hilly centre	Mostly planar
Land area (km ²)	5531	1120
Peak load (MW)	1080–1160	270–290
Energy consumption (GWh)	4807	1202
PV installations	229.1 MW	40%
Wind installations	157.5 MW	48%
Biomass installations	12.1 MW	100%
Conventional capacity	1658	39.1%

Table 2 Capacity of the conventional generating units in Cyprus

Power stations	Generating unit	Unit technology	Fuel type	Minimum capacity per unit (MW)	Maximum capacity per unit (MW)	MU/MD (hrs)	RU/RD (MW/hr)	Cr
PP1	1–4	Gas turbine	Diesel	4	37.5	1	34	2
PP2	5	Gas turbine	Diesel	4	38	1	34	2
	6–8	Steam turbine	HFO	66	130	6	60	
	9–10	Combined cycle	Diesel	66	216	8	120	
PP3	11–13	ICE	HFO	8.75	50	3	50	2
	14–16	ICE	HFO	14.5	50	3	50	
	17–22	Steam turbine	HFO	30	58	8	28	

Fig. 3 Strategic operation of the proposed VPP



national, passing sequentially from the distribution to the transmission system and then to the national grid. In case of electricity deficits, electric power from neighbouring conventional power plants is committed and obtained directly via the transmission system connection.

The electrical power transactions with the national grid per month during 2020 and 2021 are illustrated in Fig. 4, based on Eq. (1), actual generation and load data. The respective annual inputs can be observed in Fig. 5. For analysis purposes,

four scenarios are taken into account. The main features represented by the scenarios under consideration are included in Table 3. The actual scenario represents the real operation of the proposed VPP during the year of 2020. To meet the 2030's needs, the second scenario considers a 250% increase in RES within the VPP in the presence of storage. In this scenario, different ESS technologies are compared based on their life-cycle costs and the income stems from the decreased emissions of conventional power plants, the increased electricity sales and the avoided capacity upgrade of the transmission line connecting the national grid with VPP. Then, two more scenarios are needed to account for the 2050 targets. Towards decarbonisation, 100% RES are considered for the VPP and the entire conventional generation depends on hydrogen. Hence, the third scenario analyse the thermal replacement of hydrocarbon fuels by hydrogen and the total electricity production cost is compared in terms of metrics from different hydrogen production processes and 2020 values. Finally, the last scenario also involves the term of storage and assumes a 250% increase in RES, whereas all hydrogen fuel stems by renewable processes. Among the different ESS technologies compared, hydrogen storage also participates.

Following the mathematical conceptualization of balance Eq. (1), the electrical transactions of the VPP are obtained simultaneously with the power distribution on the available conventional generators. Consequently, a model is needed to extract the optimal scheduling (unit commitment to determine S_{NxT} -matrix) based on which the economic dispatch P (NxT -matrix) will be carried out. The objective, set to minimize the total production (fuel and emissions) costs, takes into account the presence and absence of storage, the variation in RES contribution and the fuel type for conventional generation.

4 Results and discussion

In order to evaluate the total production cost (TPC) in terms of fuel consumption and CO_2 emissions, the real power output of the conventional units of VPP is taken into account. Then, TPC is obtained based on the cost and emission coefficients listed in Table 2. To consolidate the respective metrics needed for the 2050 paradigm, the hydrogen coefficients found in [15] are also included. The decision on which generators must be turned on and their optimum power dispatch is made by solving a mixed-integer linear programming (MILP) task. The overall problem is formulated as:

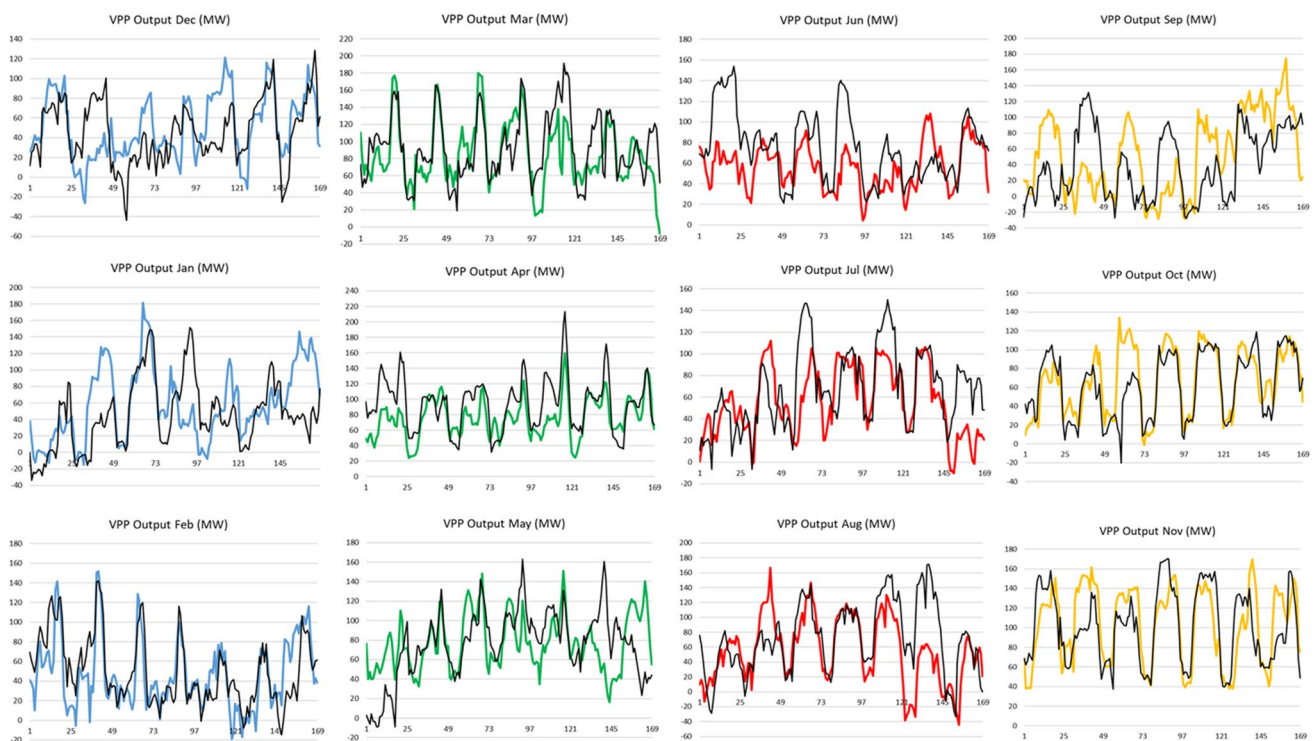


Fig. 4 Weekly VPP power variation in 2021 (black line-chart) compared with 2020 (coloured line-chart) values per month

Fig. 5 Annual VPP input to recover the domestic power demand during **(a)** 2020 and **(b)** 2021

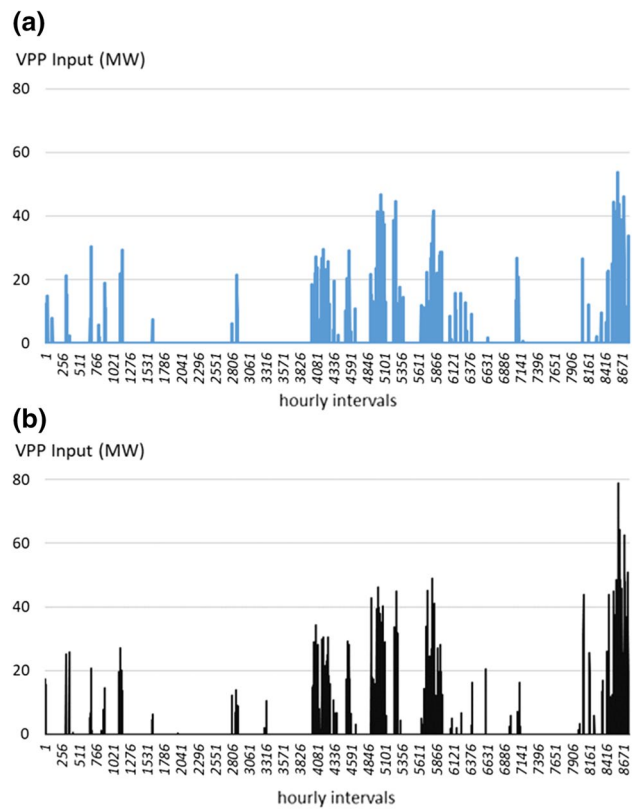


Table 3 Main features of the scenarios under assessment

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Target year	2020	2030	2050	2050
RES share	x	2.5x	100%	100%
ESS type	No storage	Zn-air Ni-Cd Li-ion	No storage	H ₂ storage Na-S Li-ion
Generators' fuel	HFO	HFO	H ₂	H ₂

$$\min_{U,P} S^T f(P), \tag{15}$$

such that $P_i \in [P_i, \bar{P}_i], S_i \in [0, 1]$ and $h_k(S, P) \leq 0$. For the sake of simplicity, we can assume that the objective (15) is linear and equality constraints (e.g., power balance) are replaced by two inequalities. Moreover, the non-linear requirements h_k can be met under the imposition of additional constraints. For example, in case of the satisfaction of minimum-up and minimum-down constraints the following conditions have to be retained:

$$h_1(S_i^t) = MU_i - \sum_{t=t_{off}}^t (1 - S_i^t) \tag{16}$$

$$h_2(S_i^t) = MD_i - \sum_{t=t_{on}}^t S_i^t, \tag{17}$$

where t_{off} shows the time the i th generator was shut down and MU_i represents the minimum off-time that must be elapsed before its start-up. MD_i expresses the on-time that must be elapsed before a shut down of the unit, considering

the time of start-up t_{on} . Similarly, the satisfaction of ramp-up (RU_i) and ramp-down (RD_i) requirements are realized via the help of Eqs. (18) and (19).

$$h_3(P_i^t) = RU_i - (P_i^t - P_i^{t-1}) \tag{18}$$

$$h_4(P_i^t) = RD_i - (P_i^{t-1} - P_i^t) \tag{19}$$

Finally, within a particular plant j with N available generators, the maximum number of actions that can be simultaneously performed is restricted via the crew constraint (Cr) of Eq. (20).

$$h_5(S_i^t) = Cr_j - \sum_{i=1}^N (S_i^t - S_i^{t-1}) \tag{20}$$

The program was written in MATLAB (MATLAB R2020, MathWorks) and experimental results obtained by making use of actual data and performing weekly simulations on a computer with Intel-Core i7-4510U CPU @2.6 GHz, 64-bit operating system (Windows 10), and 6 GB of memory.

4.1 Electricity transactions and RES share improvement

According to actual data, obtained from the Cyprus energy regulatory authority (CERA), the generation from ICE and steam units during the year of 2020 (scenario 1) is in the order of 229.39 GWh and 1259.59 GWh, respectively. On the other hand, the contribution of RES is rated at 131.44 GWh, 130.69 GWh and 49.45 GWh corresponding to PVs, wind and biomass plants. This results in 596.06 GWh injections to the national grid and 7.799 GWh of purchased energy, which offers an income of 45.255 M€ if the purchased and selling electricity-cost rates are 0.25€/kWh and 0.15€/kWh, respectively. The share of RES at VPP level is 25.73% corresponding to 13.44% at the whole power system. Finally, RES producers are paid at the average avoidance cost of conventional generation as shown in Eq. (21). This constitutes an addition of 8.844 M€ in total expenses.

$$f_{RES} = \frac{TPC}{\sum_{t=1}^{8760} P_i^t} \tag{21}$$

In scenario 2, the increase of 250% in RES contribution lowers the conventional impact on both fuel and emission cost. However, the application of storage adds considerable costs both in capital and O&M expenses. The size of the assessed ESS in terms of rated power and energy capacity, accounts for the maximum autonomy of the VPP considering the worst case of an islanding event and the maximum system security based on the capacity of the transmission system interconnector (a double-circuit twin-Rubus conductor of total capacity ~ 400 MW is assumed). Therefore, it is calculated based on the following equations.

$$P_{rated} = \left| \min_{t=1:8760} (P_{Grid}^t) \right| \tag{22}$$

$$E_{cap} = \max_{d=1:365} \left| \sum_{t=1}^{24} (P_{Grid}^t < 0) \right| \tag{23}$$

The payback cost for the renewable electricity reaches 20.6 M€ annually.

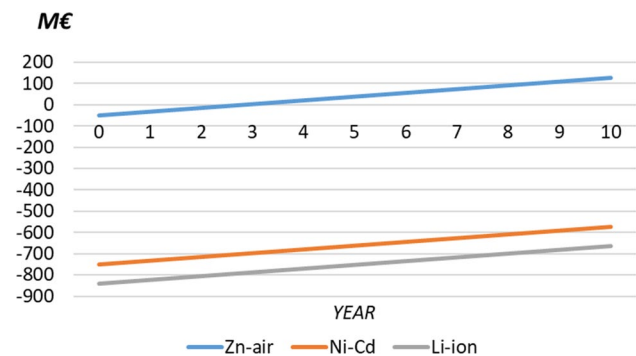
A further key parameter to estimate the total cost of the proposed ESS is the energy stored. This is needed to calculate the variable portion of O&M costs, since they are measured in €/MWh of stored energy E_s . Three ESS technologies are analysed based on the technical and cost metrics of Table 4, a 5% discount rate and 10-year useful lifetime. The increase (250%) of RES within the VPP, resulted in decreased conventional electricity from steam (equivalent to 810.732 GWh) and consequent emissions, from 44.147 M€ to 27.462 M€. Although, the exported electricity increased to 615.157 GWh (the imported remained almost the same—7.678 GWh), the income fell dramatically. The only viable solution is given by Zn-air battery cells, which shows an income of 10.467 M€ annually, despite the quite low performance characteristics. Ni–Cd and

Table 4 Performance characteristics of the electricity storage technologies under assessment

Characteristics	Zn-air	Ni-Cd	Li-ion	Na-S	Regenerative FCs
Round-trip efficiency (%)	60	75	90	90	50
DoD (%)	85	85	85	100	90
SDR (%)	0	0	0	0	2
C_{BoP} (€/kW)	360	360	360	360	^a
C_{PCS} (€/kW)	60	60	60	60	2918
C_{ESM} (€/kWh)	35	1150	1550	400	15
$C_{f-O\&M}$ (€/kW-year)	0	5.36	2.68	21.44	20.0
$C_{v-O\&M}$ (€/MWh-year)	0	^b	0.54	^b	0.4
E_{cap} (MWh)	790.22	632.17	526.81	907.03	503.91

^aBoP cost is included in PCS cost

^bVariable O&M cost is included in fixed O&M cost

Fig. 6 Annual cumulative income pertaining the ES technologies in scenario 2

Li-ion occur infeasible, providing annual expenses above 47 M€ and 55 M€, respectively, mainly due to their high capital and operational costs. Their annual cumulative income during the assessed life cycle can be observed in Fig. 6. In the presence of storage, the share of RES reaches 64.33% and 33.6% at the VPP and whole power system levels, respectively.

Scenario 3 assumes the replacement of heavy fuel oil (HFO) with hydrogen. Although the input/output power transactions remain the same in the presence and absence of electricity storage, the enhanced coefficients show relevant fuel-cost improvements, eliminating emissions. Nevertheless, a necessary prerequisite is the origin of the exploited hydrogen from RES. The considered routes for hydrogen production are biomass pyrolysis, biomass gasification, bio-photolysis, fermentation, wind and PV electrolysis. In this regard, the total production cost with respect to the hydrogen production process cost is tabulated in Table 5. Similarly, the expenses of paying RES producers are also included. The income/outcome of the proposed VPP is estimated at 89.4 M€ and 1.95 M€, respectively. The 100% share of RES within the VPP corresponds to 33.43% for the entire power network.

The presence of storage in scenario 4, involves the regenerative fuel-cells for hydrogen storage, the high-temperature battery systems Na-S and Li-ion cells. Based on the same formulation for ESS used in scenario 2 and enhanced RES contribution in power generation (250% increase compared to 2020 values), the life-cycle cost analysis in the case of hydrogen storage varies according to the H₂ production process. Table 6 includes the TPC of the assessed routes for hydrogen production (examined in scenario 3), along with the payback cost for RES producers. Additionally, the annual cost with respect to the hydrogen storage is also included. The respective VPP income/outcome in the presence of storage is 92.274 M€ and 1.92 M€. In this case, the 100% RES share corresponds to a total 37.54% for the entire grid. Most credits arrive from biomass pyrolysis, whereas PV electrolysis is the most expensive pathway. Figure 7 demonstrates the cost performance of the proposed ESS system pertaining the best and worst hydrogen route and storage, compared with Na-S and Li-ion battery alternatives.

4.2 Emission trading system

The electricity transactions between the VPP and national grid are depicted in Fig. 8. It is worth noting that VPP input/output power remains the same during the analysis of all scenarios. The difference lies in the energy content

Table 5 Technical characteristics of the conventional generating units in VPP

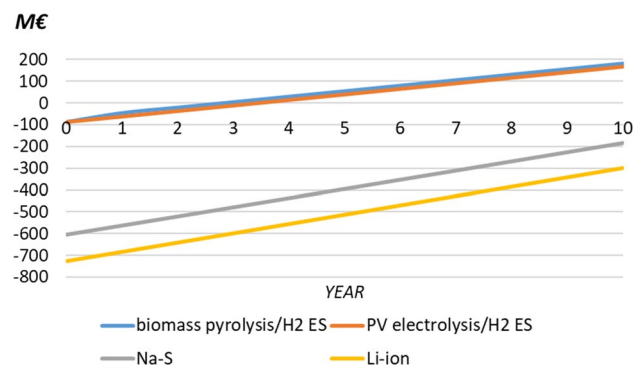
Characteristics	Steam	ICE	Steam	ICE
Fuel type	HFO	HFO	H ₂	H ₂
Fuel cost (€/MBtu)	5.05	5.05	^a	^a
a (MBtu/MW ² h)	0.0170	0.0135	0.0055	0.0045
b (MBtu/MWh)	3.734	3.423	1.214	1.112
c (MBtu/h)	60.261	10.290	19.585	3.344
Start-up fuel consumption (tn/h)	17.660	2.027	3.334	0.383
CO ₂ cost (€/tn)	5	5	0	0
a' (€/MW ² h)	0.0022	0.0018	0	0
b' (€/MWh)	0.478	0.438	0	0
c' (€/h)	7.712	1.317	0	0
Start-up emission cost (€/h)	743.84	85.36	0	0

^aHydrogen cost depends on the production route

Table 6 Cost metrics pertaining six different renewable hydrogen production pathways

	Biomass pyrolysis	Biomass gasification	Bio-photolysis	Fermentation	PV electrolysis	Wind electrolysis
H ₂ cost (€/MBtu)	23.593	26.123	25.514	29.401	180.944	78.919
TPC without ESS (M€)	5.037	5.577	5.447	6.277	38.628	16.848
RES payback without ESS (M€)	1.056	1.169	1.142	1.316	8.096	3.531
TPC with ESS (M€)	3.274	3.625	3.540	4.080	25.108	10.951
RES payback with ESS (M€)	2.456	2.719	2.656	3.060	18.834	8.214
Reg-FC annual income (M€)	27.523	27.303	27.357	27.019	13.875	22.724

Fig. 7 Annual cumulative income pertaining the ES technologies in scenario 4



during electricity selling, since the power purchasing is realised via the neighbouring power plant PP2 by making use of steam units with known emission coefficients. This way, the emission trading system exploits the renewable generation at a certain level, above which the sequential transmission and distribution losses stand against overall cost. Figure 9 encloses the flow diagram of the emission trading system towards decarbonisation.

To offer a broader overview of the proposed configuration, the renewable energy connected to the distribution and transmission system, along with the actual VPP input and output power during a typical week is presented in Fig. 10. Following the concept of the trading model, the output power from wind (connected to the transmission system) and steam generating units are formed as shown in Fig. 11. The corresponding contribution in the presence of storage is included in the following diagram (Fig. 12).

Although this configuration retains the amount of CO₂ released during receiving electricity, the extraction of CO₂ improves greatly, especially in the presence of storage. Taking into account a penalty cost for CO₂ (π_{CO_2}) as high

Fig. 8 VPP electrical power transactions with national grid

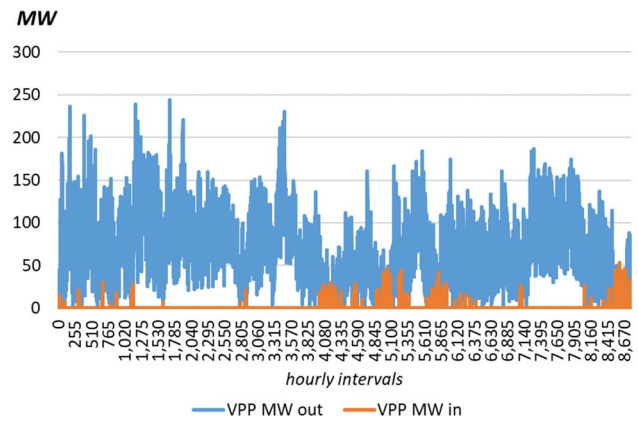


Fig. 9 Emission trading system flow diagram

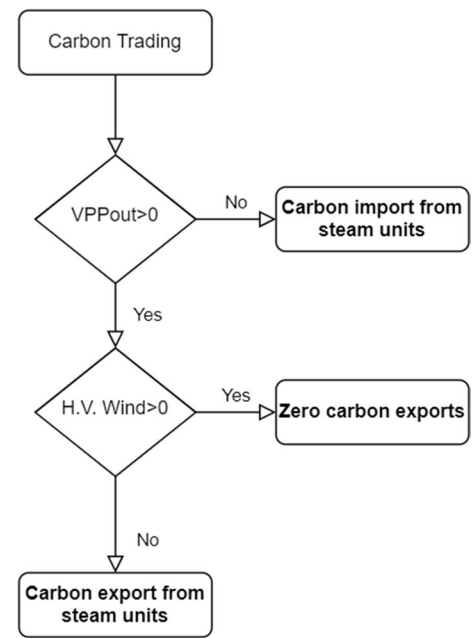
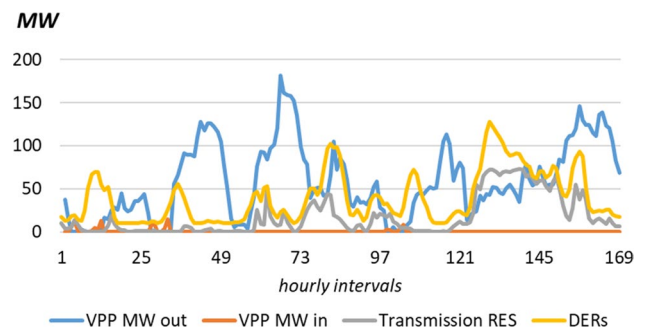


Fig. 10 Hourly VPP variation between input and output power



as 5€/tn, the annual amount of 7.799 GWh import of electricity corresponds to 4958tn of CO₂. Before storage, the export electricity rated at the annual 591.016 GWh is responsible for the emission of 75418tn of CO₂. This impact is mitigated in the presence of storage where the annual amount of CO₂ released is 58360tn. The variation in carbon-dioxide emissions is illustrated in Fig. 13 for the representative week. For completeness sake, Table 7 illustrates the obtained results with respect the assessed scenarios.

Fig. 11 Hourly variation of the exported electricity from wind and steam through transmission

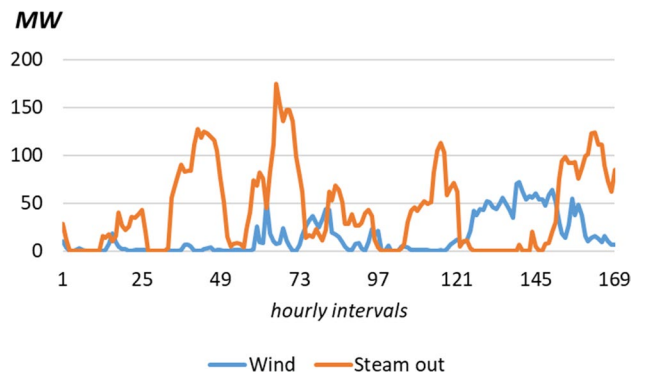


Fig. 12 Hourly variation of the exported electricity from wind and steam through transmission in the presence of ESS

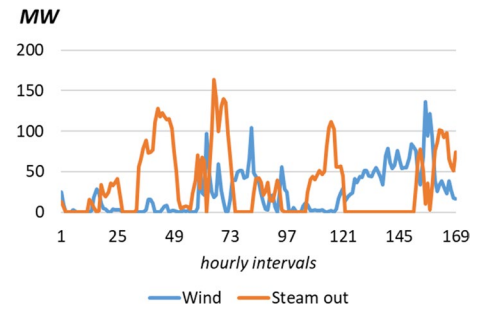


Fig. 13 Hourly variation of the amount of CO₂ released during importing and exporting electricity

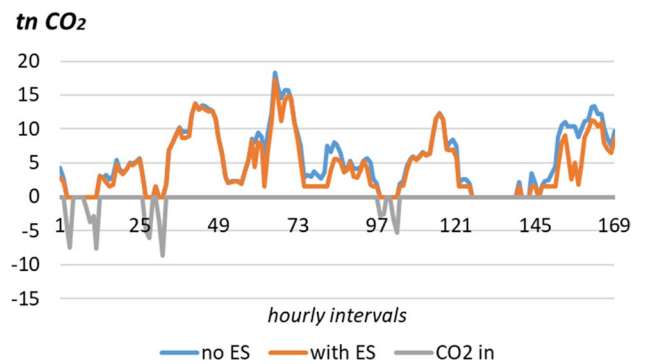


Table 7 Annual results relating to the assessed scenarios

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Minimum TPC (M€)	42.197	27.462	5.037	3.274
Minimum RES cost (M€)	8.844	20.600	1.056	2.456
Maximum income (M€)	36.411	31.825	81.360	112.148
RES share at VPP level (%)	25.73	64.33	100	100
RES share at national grid level (%)	13.44	33.6	33.43	37.54
VPP total CO ₂ emissions (tn)	210,173	136,612	0	0

The isolated system of Cyprus constitutes a representative island system within European Union. Between the member states, Cyprus may possess the most challenging task with respect to RES integration, due to its isolation and remoteness from other, mainland territories. In this regard, the proposed model can adequately produce similar effects in other EU countries and provide a potential, scalable tool towards renewable energy utilization in the whole EU super-grid.

5 Conclusions

In this work, the performance of a virtual power plant has been assessed towards optimal carbon-electricity trade-offs. The configuration was tested for the case of Cyprus, an islanded, non-interconnected power network that relies on imported fossil fuels and domestic wind, PV and biomass systems. Dividing the system by electricity centres, the proposed VPP constitutes the one fourth of the total load demand, 40% of the total PV installed capacity, four wind farms which accounts of around the half wind-produced electricity and one biomass plant. Relating to the conventional generation, 12 generating units are at the VPP's disposal and concern 6 steam units and 6 internal combustion engines.

5.1 RES cost credits

The feasibility of the proposed configuration is examined in terms of fuel and emission cost mitigation, in the attempts of EU to increase the share of renewable contribution in power generation. In this regard, the proposed VPP is assessed under four scenarios, each of which refers to a different target. Scenario 1 represents the 2020 paradigm and builds a reference for the rest case-studies. The 2030s targets of 250% increase in RES contribution within the VPP are demonstrated in scenario 2 in the presence of storage, while scenario 3 constitutes the case of 100% RES with fossil-fuels replacement with hydrogen. The last scenario assumes the same targets and comparisons between different hydrogen production processes in the presence of storage. Based on similar input/output power transactions, scenario 2 and scenario 4 compares three different storage technologies subjecting them to life-cycle analysis.

Analysing the power system of Cyprus, prospects for RES enhancement, emission and fuel cost improvement do exist. The 25.7% of RES contribution can reach up to 64.3% by lowering the annual income from 36.411 M€ to 31.825 M€. Although some cost credits arise from emission avoidance costs and less fuel recovered by RES, the application of storage constitutes a necessity to retain energy security and system autonomy. Apart from the zinc-air battery systems, no other ESS can become viable solution. The results of scenario 3 (2050 paradigm) reveal that a 100% renewable system within VPP is feasible, offering maximum income when the produced hydrogen stems from biomass pyrolysis. The same is ensured in the 4th scenario, while the enhanced RES in the VPP are combined with regenerative fuel cells as the ESS solution. The respective annual incomes for the two scenarios (scenario 3 and 4) reach the whopping 81.360 M€ and 112.148 M€.

5.2 Carbon cost credits

Apart from the optimal electricity transactions, the proposed VPP strategically regulates the CO₂ exchanges in such a way that minimizes the annual amount of released emissions and total production costs. This is facilitated by minimizing the annual RES curtailment with the aid of storage, the size of which is optimally defined at 53.619 MW and 412.286 MWh. The annual CO₂ emissions counted to 210,173tn in 2020 scenario, decreases to 136,612 during 2030 paradigm and are eliminated in 2050 case studies with hydrogen. As for future directions to research we indicate the consolidation of more emission cost coefficient to estimate the overall impact of other GHG emissions like CO, CH₄, NO₂ and SO₂.

Besides the avoidance of an islanding event and the maximum system security achieved based on the transmission-interconnected capacity, the VPP utilization factor cannot be maximized to bring further credits. The size of storage could be optimized in real-time electricity markets to further increase the income on a daily basis. This requires an alternative model able to transform the convex linear programming problem into a non-convex non-linear problem with additional constraints. However, the formulation of such a multi-objective task could achieve great improvements not only in costs, but also in VPP utilization.

Author contributions P.N.: conceptualization, methodology, software, investigation, writing—original draft preparation and visualization, A.P.: validation, formal analysis, resources, data curation, writing—review and editing, supervision and project administration. All authors reviewed the manuscript

Declarations

Competing interests The authors declare no competing interests.

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