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Building sustainable power mix in small island grids: a multi-criteria analysis¹

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Abstract— Islands have traditionally experienced great dependency on external energy supply and many of them opted for diesel as fuel for power generation. This study tests scenarios of different levels of renewable penetration on the French Atlantic island Ouessant, facing the general problems of the energy planning such as grid reliability, the lack of economies of scale and reduced investor profitability. A complex model is built combining long-term investment routines with short-term hourly plant dispatching, following a parametric procedure. The energy mix is composed of wind – PV – tidal power plants and distributed battery storage. Their sizes adapt to the peaking loads, leading to an oversized infrastructure and to low usage rates due to loss of market opportunities during low demand hours. New evaluation criteria are necessary to policy makers in the selection of the energy mix, based on the performance of each plant and storage device, the cost of each power facility and the total system cost. From the investor perspective, the key indicator is the loss of energy generated, therefore storage will support the integration of intermittent renewables by avoiding the power curtailed and accurately sizing the generation mix. The final trade-off is between the reasonable rates of energy in excess to be curtailed, the cost of additional storage and the loss of load probability, which are socially and economically admitted by the regulator and by energy operators, having each conflicting interests and objectives.

Keywords— *Optimal power system sizing, off-grid islands, renewables, storage, curtailment*

I. INTRODUCTION

Islands have traditionally experienced great dependency on external energy supply and many of them opted for diesel as fuel for power generation. They are involved since some years into an energy transition process to increase their energy independency while reducing greenhouse gas emissions. The main issue of their transition in the power sector is the continuity and reliability of the supply, which tend to be exacerbated when based on fluctuating renewables. Therefore coupling with storage devices, mostly managed in a centralized way, like a hybrid generation-storage project seems to be the natural solution.

Hybrid projects made of renewables and storage systems have been investigated over the last twenty years in particular on islands and remote areas [1-3]. The state of the art is hence rich in successful projects in the Azores, the Canary Islands, the Greek Islands, the Caribbean, Bornholm, Samsø (Denmark), and many others. Most of the lessons learned are in terms of design, optimization, operation, and control of renewable hybrid energy systems, from a technology point of view. It should be stressed that isolated systems present strong constraints in terms of security of supply and high costs for the system reliability, and can easily implement new projects given the high degree of freedom of the policy makers and their local governance power. Therefore few experiences are relevant in the context of integrated visions embedding conflictual positions from stakeholders, e.g. engineers, investors, regulators and policy makers.

This framework raises the general problem of the electricity management and sizing power system in remote electrical grids to continuously reach the balance between production and consumption, but from a more complex perspective that is the choice of the energy mix from social, political, economic and technology perspectives. The hybrid power system under consideration combines wind, solar and tidal current energies with lithium-ion batteries, as the most appropriate storage media at small scale due to high round-trip efficiency and negligible discharge. The main objective of the study is to find the optimal size of system minimizing the Levelized Cost of Energy (LCOE), CO₂ emissions and the curtailed energy, i.e. the loss of potential power generation. The case study is the French island Ouessant, which sets ambitious energy targets of 50% share of renewables into power generation by 2023 and an *almost* 100% renewable power mix up to 2030 [4]. Specific constraints are documented for

this study in terms of demand peak, load variability and local energy potential and further integrated in our methodology such as to set out energy transition scenarios in support of public choice of energy schemes.

A large number of studies deals with system sizing in remote areas, e.g. island or continental village, but few modelling methods and algorithms are used (see [5] for a survey of different techniques). Iterative methods could be used, see in [6] by means of the Homer software, an optimal hybrid system configuration for a Malaysians city. Autonomous hybrid systems (PV, wind and battery) are studied in [7] by using a genetic algorithm, triggered by a two objective function combining costs and loss of load probability (LLP). An iterative method is used by [8] to determine the optimal size of power system in the remote area of Ouessant that minimizes both the system cost and the CO₂ emissions. The hybrid system under consideration is composed of diesel, offshore wind, tidal and PHS storage. The impact of LLP on the net present cost for various configurations of a hybrid diesel-PV-fuel cell system is studied in [9]. An optimization sizing model is used by [10] to determine the minimum LCOE of an off-grid system with respect to LLP index. The effect of reliability index on the cost of energy is also analyzed in [11] for a stand-alone hybrid system composed of PV, wind and batteries. Using an iterative method [12] seek to minimize the Levelized cost of energy. They found that the power source diversification (tidal, PV, on-shore wind and battery) may help attaining the double objective of low LCOE and low unmet load. A particle swarm optimization algorithm is built in [13] to size a power composed of PV-diesel generator and battery bank with respect to three objective function, including the total system cost, the loss of load probability and CO₂ emissions. It is found that for low levels of LLP, marginal increases in unmet loads significantly decrease the CO₂ emissions. GAMS and Homer softwares are combined in [14] to study the impact of demand response (DR) program on the size of a stand-alone power system. Results show that DR significantly affects system cost by reducing the use of battery. Other studies analyze the importance of share of electricity curtailment on the optimal size and the composition of hybrid systems under consideration [15].

Based on selected evaluation criteria, this study builds a complex model combining long-term investment routines over decades with short-term hourly plant dispatching modules, following a parametric procedure. The energy mix is composed of wind-PV-tidal power plants combined with distributed battery storage devices. Their size will adapt to the peaking demand values and are expected to lead to an oversized infrastructure related to the yearly needs of the island. Consequently their usage rate will be low due to the loss of market opportunities that prevent to fully exploit the assets during low demand hours. Thus the island energy planning will face a double issue of the lack of economies of scale leading to capacity oversizing, and reduced investor profitability due to energy curtailed. New evaluation criteria are necessary to policy makers in the selection of the energy mix combining the performance of each plant and storage device and their centralized management, the cost of each power plant and the total system cost, and the reliability of the power supply. From the investor perspective, the key indicator will be the loss of energy generated, therefore the use of storage could support the integration of variable renewables by avoiding the power curtailed and by accurately sizing the generation mix.

The remaining paper is organized as follows. Section 2 describes the mathematical representation of the system. Section 3 presents the study case, Section 4 depicts the model results, and the final part concludes.

II. MODEL DESCRIPTION

The objective of this paper is to determine the optimal size of power plants in a remote power system. The case study will consider a hybrid system consisting of PV installed on top-roofs in particular (*pv*), an on-shore wind farm (*w*), a tidal farm (*tid*), a battery bank (*st*), and, according to scenarios, a diesel generator (*dg*). Hybrid power system means that the operation of the power plants and storage devices is

based on the management of the power supply and the energy charging-storage-discharging in a centralized way.

A. Modelling methodology

An optimization model is built to minimize the total life-cycle cost of the stand-alone system, under a set of constraints describing the technology availability, the operational limitation of each technology and the energy balance requirement. The model uses Mixed Integer Programming implemented in the software Gams with Cplex solver². The model is dynamic, simulating a local market, hour-by-hour.

The model is a partial equilibrium model, which endogenously determines the most cost-efficient combination of existing technologies that meets the demand. The power demand is fixed, non-constant at each hour and price inelastic. The supply aggregates the power generated locally.

Inputs are the hourly load profiles of renewable energy by technology, i.e. solar, wind and tides. The decision variables for the long-term investment are the number of each component of the system, such as the on-shore wind turbines, the solar PV panels, the size of the tidal farm, the capacity of the diesel generator and the number of batteries. On the short-term, the decision variable is the hourly dispatching of power plants and their operation.

The **objective function** represents the sum of the present cost of each technology, setting the total present cost (TPC) and the operating fuel cost of the diesel generator:

$$\begin{aligned}
 TPC = & \sum_{tech} (fix_cost_{tech}) N_{tech} \times K_{tech} \\
 & + \sum_h (var_cost_{dg}) \times P_{dg,h}
 \end{aligned} \tag{1}$$

N_{tech} stands for the number of technologies by type $tech$ included in the hybrid system according to the island natural energy potential (solar, PV, tidal) and installed capacities (diesel and battery), K_{tech} is rated capacity of technology $tech$, var_cost_{dg} is the variable cost of the diesel generation ($P_{dg,h}$) and h is the time step, here the hour.

Several constraints are added next to the system such as to describe the hourly operation of each plant type over the year.

At each time step, the power **supply must equal the demand**, whereas in some scenarios the energy balance includes the possibility to locally admit loss of loads:

$$\sum_{vres} P_{vres,h} + P_{dg,h} + P_{dis,h} = P_{load,h} + P_{ch,h} - LOL_h \tag{2}$$

$P_{vres,h}$ and $P_{dg,h}$ stand for renewable and diesel generation where applicable, $vres$ counts for variable solar, wind and tidal technologies, and $P_{ch,h}$ and $P_{dis,h}$ represent the operation of storage in charging mode and in discharging mode, respectively. In some scenarios, the supply-demand equilibrium is not met, admitting thus positive values for loss of load, denoted LOL_h , representing the hourly unserved load. This indicator will be next used to investigate the impact of the unmet load on the system cost and on the amount of the energy in excess. The hourly **loss of load aggregation** over the time horizon is limited by total load: $\alpha_{lol} \leq 1$. If $\alpha_{lol} = 0$, the demand is entirely met.

$$\sum_h LOL_h \leq \alpha_{lol} \sum_h P_{load,h} \tag{3}$$

² www.gams.com/dd/docs/solvers/cplex.pdf

Non dispatchable generation is constrained by the installed capacity and by the (exogenous) hourly energy potential profile.

$$P_{vres,h} \leq profile_{vres,h} \times N_{vres} \times K_{vres} \quad (4)$$

The energy curtailment, or the flow of dump energy, which applies to non-dispatchable generation (wind, solar and tidal) is the crucial indicator in this study to evaluate the performance of the hybrid system.

We define the dump energy ratio as the share of renewable energy potential that is not generated and thus is lost. The following equation allows investigating the consequences of limited curtailment which might be added in some scenarios, where α_{curt} stands for constrained **curtailment rate**:

$$\begin{aligned} \sum_{vres} \sum_h (P_{vres,h} - profile_{vres,h} \times N_{vres} \times K_{vres}) \\ \leq \alpha_{curt} \times (profile_{vres,h} \times N_{vres} \times K_{vres}) \end{aligned} \quad (5)$$

Diesel generator. In most of remote areas, diesel generators are used either to supply the entire generation or to ensure the system reliability, or both. Here the diesel is employed to residually meet the demand after using the natural potential of renewables, and it is constrained by the installed capacity:

$$P_{dg,h} \leq N_{dg} \times K_{dg} \quad (6)$$

In line with [13], it is assumed next that the diesel **fuel consumption** is a function of the nominal power and the rated power of the generator:

$$F_h = A \cdot P_{dg,h} + B \cdot (N_{dg} \times K_{dg}) \quad (7)$$

While the diesel generator is operating, it is assumed that it will remain above a certain threshold in order to avoid continuously being shut-down and started-up in front of renewables fluctuations, hence permanently consuming fuel. Two values are then estimated, one for the fuel consumption while generating at optimal efficiency, and one for the sub-optimal efficiency while being at the minimum threshold of generation; these values correspond in (7) to parameters A and B, estimated at 0.204 and 0.014 based on [8]. Diesel generation comes with CO2 emissions. Diesel emission coefficient is set at 2.66 kg per litre of fuel and we assume a CO2 price of 100€ per ton.

Storage system. Storage is used to balance the power demand and supply, in a hybrid way meaning that the storage is charging renewables in excess only for discharging during low renewable potential periods such as to meet the demand, and excludes that the optimal use of batteries or strategical speculative trade. In the model, the storage aggregates batteries and forms a fleet or a bank of devices, and next the **storage dynamics** is described following the hourly state of charge of the bank (*SOC*):

$$SOC_h = SOC_{h-1} \times (1 - \sigma) + P_{ch,h} \times \mu_{ch} - \frac{P_{dis,h}}{\mu_{dis}} \quad (8)$$

where σ is the self-discharge rate and μ_{ch} and μ_{dis} are respectively charging and discharging efficiencies.

In order to prevent the reduction of the battery lifetime due to accelerated fatigue, the battery cycle is bounded as follows:

$$(1 - DOD) \times N_{batt} \times SOC_{max} \leq SOC_h \leq N_{batt} \times SOC_{max} \quad (9)$$

where DOD stands for the maximum depth of battery discharge, set at 90% [16], and SOC_{max} is the maximum level of the stock given by the nominal capacity of a battery.

As operational constraints, the **batteries are either charging or discharging** and cannot simultaneous do both [14]:

$$P_{ch,h} \leq M \times on_{ch,h} \quad (10)$$

$$P_{dis,h} \leq M \times on_{dis,h} \quad (11)$$

$$on_{ch,h} + on_{dis,h} \leq 1 \quad (12)$$

where $on_{ch,h}$ and $on_{dis,h}$ are binary variable, representing battery operation status, e.g. $on_{ch,h} = 1$ at hour h means that the battery is in charging mode. Equation (12) ensures that $on_{ch,h}$ and $on_{dis,h}$ cannot be equal to one simultaneously. The parameter M is here selected as a positive value, larger than the battery capacity, i.e. some 1,000,000 to ensure feasibility.

B. Evaluation indicators

As mentioned above, the aims of the study is to determine the optimal size of a stand-alone hybrid system through a multi criteria optimization process. Commonly used criteria in the literature are the system cost, the reliability and the excess of electricity, or the power curtailment. Next are introduced the criteria considered in this study.

The cost indicator is the total present cost of the system, which is the sum of the cost of all components, including the acquisition cost, the fixed operation and maintenance cost, the replacement cost and, where applicable, the diesel generation cost, minus the salvage value. The costs and values are all, but the later one, actualized:

$$TPC = \sum_{tech} (C_{tech}^{inv} + C_{tech}^{fom} + C_{tech}^{remp} - C_{tech}^{res}) \times N_{tech} \times K_{tech} + \sum_h C_{dg}^{fuel} \times P_{dg,h} \quad (13)$$

The total present cost of the system is defined as the sum of the actualized cost of each component, initial capital cost, fixed operation and maintenance cost, replacement cost, salvage value and variable operating cost of the thermal component. Capital letters C stand for present values and lower case letters c_{tech}^{inv} , stand for the actual investment cost per kW. The investment cost of the system includes all components costs (wind farm generators, towers and controllers, PV panels, tidal turbines and the battery bank), the cost of civil work, installation and the connections cables.

The **actualized fixed operation and maintenance** (fom) cost and the fuel cost, where applicable, are evaluated for each component as follows:

$$C_{tech}^i = \frac{cost_{tech}^i}{CRF(r, T)} \quad i = fom, fuel \quad (14)$$

where CRF is **the capital recovery factor**, r the actualization rate and T is the system:

$$CRF(r, T) = \frac{r(1+r)^T}{(1+r)^T - 1} \quad (15)$$

As the lifetime is different by component, a **replacement cost** is accounted for at the level of each technology initial investment cost:

$$C_{tech}^{rem} = c_{tech}^{inv} \times \sum_{\theta=1}^{N_{rem}} \left(\frac{1}{1+r} \right)^{\theta \times \tau_{tech}} \quad (16)$$

In (16), $N_{rem} = \text{int} \left(\frac{\tau_{tech}}{T} \right)$ is the number of times a technology $tech$ has to be replaced over the lifetime of the entire system and τ_{tech} is the lifetime of each component of the system.

At the end of the lifetime of the system, some components are not fully depreciated, so **residual value** is obtained as follows:

$$C_{tech}^{res} = c_{tech}^{inv} \times \left(\frac{1 - (T - \tau_{tech})}{\tau_{tech}} \right) \quad (17)$$

Reliability index. In addition to the system cost, the study evaluates the system through its reliability. Reliability definition could cover different concepts, such as security of the supply or capacity adequacy [5]. The former deals with the ability of system to maintain stable operations in all circumstances, whereas the latter is related to the capacity of the system to satisfy the demand. Referring to the later one we introduce in the model the **loss of load probability** index, LLP , as a proxy of reliability:

$$LLP = \frac{\sum_{h=1}^H LOL_h}{\sum_{h=1}^H P_{load,h}} \quad (18)$$

where $P_{load,h}$ is the total demand on the island at hour h .

III. CASE STUDY AND INPUT DATA PRESENTATION

Ouessant Island is a French territory located in the Atlantic Ocean, at 25 km from the Brittany coast, with an area of 15 km². Its Global Positioning System coordinates are 48° 27' 18.367" N 5° 5' 51.454" W. The island counts some 846 regular inhabitants [17] but around 3,000 inhabitants during summer. According to hourly load from the French Transmission Operator (RTE), the annual electricity consumption is 6.37 GWh in 2014, the average daily consumption is 17.4 MWh and the peak load is 1,800 kWh. By means of efficiency measures, the load is assumed to decrease by 35% until 2030 [4]. Currently, energy is produced by the means of 4 diesel generators for a total capacity of 4.4 MW. The computational power constraints the study horizon to 12 representative weeks, each corresponding to the third week of each month. The number of hours is 2,016 (24*7*12). Within this new time horizon, the annual electricity consumption is of 927 MWh.

Renewable energy potential is estimated hourly, following the methodology described in [12], for each wind, tidal and solar natural inflows. Data are taken from Copernicus Atmosphere Monitoring Service (CAMS) database for solar radiation, from OpenOcean SAS for wind inflows, while the tidal potential is based on five minute tidal data documented by the French Hydrographic and Oceanic Marine Service. Capacity factors are obtained as follows: 22.6% for tidal, 16.2% for solar PV and 47.9% for wind.

Technico-economic specifications of the hybrid system are presented in table I.

TABLE I. TECHNICAL-ECONOMIC SPECIFICATIONS OF GENERATION TECHNOLOGIES

Technology	Rated capacity kW	Technical lifetime years	CAPEX €/kW	Fixed O&M costs €/kW	Fuel price €/liter
PV	0.2	25	1800	50	
On shore wind	900	20	1500	47	
Tidal	500	25	6800	250	
Diesel	950	20	1000	30	1.5

Photovoltaic panels. The PV total installation cost is estimated in the range of 1,600 €/kW and 3,300 €/kW in the north of France, depending on the application type, commercial or residential [20], and by 2030, they are expected to decrease by 60% [16]. As most of PV panels on small islands are residential, we assume the PV panels have 0.2 kW each, an investment cost of 1,800 €/kW in 2030, and fixed O&M costs of 50 €/kW.

Wind turbines. Installation costs of on-shore wind turbines are between 1,300 and 1,700 €/kW for 2 MW generators [20], and they could still decline, i.e. by 12% in 2025 [16]. Our study assumes on-shore wind turbines of 900 kW each, at costs at the upper bound of the estimates, i.e. 1,500 €/kW in 2030.

Tidal farm. Capex costs of tidal turbines are hard to define, because they are at different stages of development and cover several technology types, but basically they are at a demonstration project stage (TRL 7-8). In [8], the capex cost is set at 6 M€ for a tidal turbine of 0.5 MW; similarly, it is of 6.8 M€/MW for a 0.3 MW turbine in [12], and in the range of 4 M€/MW and 13 M€/MW in [20] for capacities lower than 10 MW, on an international basis, but more expensive for France, i.e. 21 M€/MW. Cost is nevertheless expected to decrease in the future, as technology becomes mature with increased installed capacity. In line with [20], this study sets a total investment cost of 6.8 M€/MW in 2030 for a 500 kW rated power tidal turbine.

As the peak load in 2030 is assumed to be 911 kWh within the 12 representative weeks, the diesel generator capacity is set at 950 kW such as to ensure the system reliability at any moment. CO₂ coefficient is 2.66 kg/liter of fuel. Other values are 5% for the discount rate, and 25 years for the system lifetime, at the level of the longest lifetime technology among system components.

Battery. Lithium-ion batteries seem to be the most appropriate storage media for small scale hybrid systems due to high round-trip efficiency (96%), depth of discharge (90%), negligible self-discharge rates (0.166% per day) and reasonable long life-time (15 years). Their costs have sharply decreased so far and attain overall levels in the range of 200 \$/kWh and 1,200 \$/kWh depending on the application type [16, 18]; in between these values, estimates are around 850 €/kWh [12]. By 2030, costs are supposed to decline by about 50% - 60% [16], which makes us assume a battery cost of 500 €/kWh in 2030 (table II).

TABLE II. BATTERY SPECIFICATIONS

Rated capacity	Charging efficiency	Discharging efficiency	DOD	Lifetime	CAPEX	Fixed O&M costs
kWh	%	%	%	years	€/kWh	€/year
1 000	0.98	0.98	90	15	500	18

Finally, the number of each component is limited to take into account space scarcity, specific to small islands. Hence, the maximum number of PV modules is 2,000, corresponding to about 2,000 m² of PV array. The number of turbines is limited at 5, for each wind and tidal. As for batteries, considering their support to renewables and to the system reliability in particular in scenarios without diesel generators, their number can be substantially high, i.e. 1,000 devices as the maximum number in the model.

IV. RESULTS AND DISCUSSION

The optimization of installed generation capacities in 2030 is based on two scenarios, the first setting the target of 100% renewables (*A*), and the second testing options to reduce the infrastructure size (*B*) by punctually shaving the load over the year (*B.1*), by reducing the energy curtailment rate (*B.2*), by a combination of both options (*B.3*) and finally scenario *B.4*. assumes a limited share of thermal

generation. Several cases are tested, in order to select the best technical-economic combination of energy projects, based on the mix design (a) and on a certain degree of thermal generation in the energy mix (b).

A. Scenario 100% renewables

In this scenario, the number of diesel generators is fixed at zero. Moreover, the mathematical problem has been solved by constraining investment and dispatching such that the load is met at any moment ($\alpha_{lol} = 0$) and that the curtailment rate is unconstrained ($\alpha_{curt} = 1$). This scenario is the application of the political target of the island energy transition plan, and represents in this analysis the reference case. Results are aggregated over one year and show the optimal selection of the technology mix (see Table III). In 2030, meeting the demand requires 2 tidal turbines (or 2 MW tidal capacity), 2 wind generators (or 2 MW on-shore wind), and 1,515 PV panels (or 0.3 MW). It also requires 7 batteries as backup to ensure system reliability, or 7 MWh storage capacity.

TABLE III. RESULTS IN TERMS OF COSTS AND CAPACITY, SCENARIO 100% RENEWABLES

Total cost M€	Tidal		Wind		PV		Battery	
	N_{tid}	Generation MWh	N_w	Generation MWh	N_{pv}	Generation MWh	N_{bs}	Capacity MWh
22	2	1 392	2	2 356	1 515	318	7	7

The total cost over the entire system lifetime is 22 M€, out of which battery cost represents more than 55%. Comparing this scenario with a 100% thermal generation mix as it used to be the case before installing tidal energy on Ouessant island, it would be 70% more expensive, i.e. 13.5 M€ in 2050 at 100€/ton CO₂.

The 100% renewable optimal mix shows a rather low contribution of tidal and PV to the total generation due to their small capacity factors, while the on-shore wind energy covers 60% of the load, logically due to its high capacity factor.

This scenario shows however a significant amount of dump energy, which is 60% of the renewable potential. The curtailment rate is quite different by technology type: 28% for photovoltaic energy out of its potential, 31% for tidal and 69% for wind energy of its theoretical potential.

That is, curtailment rates are rather high from an investor perspective, as it could reduce the attractiveness of investments on the island knowing that at least one third will be dump and not sold.

Reducing the maximum curtailment rate implies mathematically that $\alpha_{curt} < 60\%$. Several levels will be tested successively such as to investigate the consequences in terms of system cost.

B. Scenario infrastructure re-sizing

1) Scenario Load shaving

Next simulations test the influence of the constraint set on the balance supply and demand, by introducing the possibility to have unmet loads, reflected in the loss of load probability (LLP). The starting point is the finding that accepting cuts in demand could significantly influence the system infrastructure and ultimately the system cost [7, 9, 10]. As load shaving reduces the need for large generation and storage capacity, this limits the peak loads. Fig 1 plots the total system cost (TPC) for values of LLP in the range of 0% and 10%.

Fig 1 shows that accepting 5% loss of load, reduces the system cost by more than 50% as the required number of batteries decreases. It is important to notice that the quantity of dump energy is only marginally affected by the LPP rate. In all simulations, curtailment rate ranges between 50% and 60%. According to this criterion, the hybrid system is oversized.

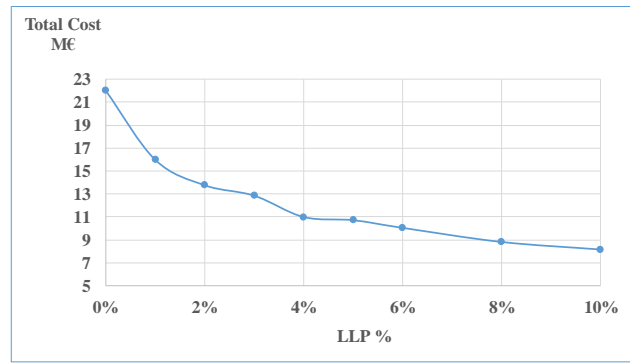


Fig. 1 Impact of loss of load probability on the system cost

Figure reading: A value of 0% of lost load implies that the entire demand is met, whereas a 10% LLP means, for example, that, in average, load might be unmet 1.2 hours per day, but here it is about load shaving, i.e. only partially unmet during one hour.

2) Scenarios Reduced Curtailment

Reducing curtailment rate is a first step towards a reduction of the size of the energy mix and the system cost as well. In this scenario, we assume that the entire demand is served, e.g. $\alpha_{tot} = 0$. Fig. 2 depicts the value of total system cost (TPC) for different values of curtailment. It shows that for constraining values of curtailment, lower than 10%, the present system cost increases sharply, and that above the critical point of 10% it increases steadily compared to the reference case of 22 M€. This cost increase is triggered by the cost of storage, since the number of batteries is necessarily higher such as to store the surplus (see Fig. 3). For instance, at low curtailment levels, under 10%, the battery total cost stands for more than 90% of the system cost. While at 30% curtailment rate, the share of battery cost in the total cost is 75%. Hence, reducing dump energy comes with important investment costs in battery storage.

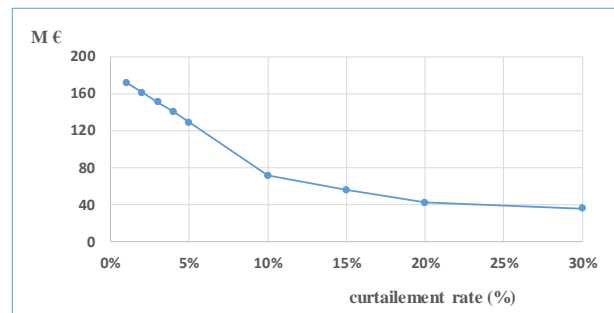


Fig. 2 Influence of maximum curtailment rate on Total Present Cost

For every curtailment rate simulated (from 1% to 30%), the optimal mix selected contains exactly 1 tidal turbine and 1 wind turbine, while the number of batteries and PV panels evolves. Yet, the number of PV panels remains 0 until the curtailment rate reaches 15%, and then increases sharply (Fig. 3). This is partly explained by the hourly potential profile of the PV energy which over the year, excepted some hours, is less correlated with the demand; while wind and tidal potentials are high enough to cover peaking loads. As shown in Fig. 3, there is a high concentration of yellow dots at the beginning of the distribution and the mix design is in favor of batteries for curtailment rates lower than 10% (see high rates of blue dots when yellow dots are close to zero).

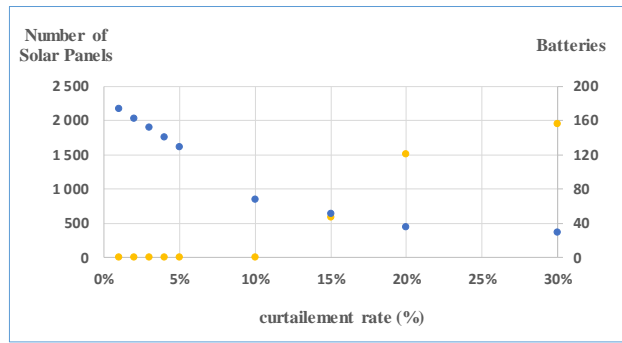


Fig. 3 Impact of the curtailment rate on PV and Battery sizing

It should be noted that curtailment and storage are complementary options up to a certain threshold (here optimally set by the model at 7 MWh of battery storage), and they become substitutable options above this optimal level.

3) Combination of load shaving and reduced curtailment

Combining both reduced curtailment rate and shaving the demand would allow redesigning the infrastructure from both demand and supply sides. Table IV presents the results of tests on the total present system cost at various levels of curtailment and loss of load probability rates.

TABLE IV. TOTAL SYSTEM COST AT DIFFERENT LEVELS OF CURTAILMENT AND LOSS OF LOAD PROBABILITY (M€)

Curtailment rate, %	% LLP					
	0%	1%	2%	3%	4%	5%
1%	172	71	62	59	57	54
5%	129	60	50	47	44	39
10%	72	59	49	37	32	27

As expected, it can be stated that accepting marginal values of unmet loads significantly reduces the system cost whatever the excess of energy is. However, the system cost is significantly high for low values of both constraints, meaning few load shading amounts and low curtailment admitted. For example, an objective of 1% of curtailment and 0% unmet load is reached for a cost of 171 M€. While accepting 1% LLP decreases the cost by almost 60%. Moreover, compared to the optimal scenario, reducing dump energy by 80% (curtailment rate declines from 60% to 10%) is possible for a small cost increase, 4.7 M€ (from 22 to 26.7 M€, + 20%), if only one accepts 5% of LLP. Thus developing demand side management allows significantly reducing the system cost for a given value of curtailment rate. Nevertheless, demand side management option are already promoted in Ponant Island where Ouessant belongs to, and makes the remaining potential in 2030 rather low, thus investing in extra demand response options could enhance a very high cost.

The impact of this set of tests on the mix design is illustrated in Fig. 4. It shows the sensitivity of the number of batteries to both curtailment target and the LLP rate: the number of batteries drops significantly when the LLP rate increases to 1% and in particular at curtailment rates of 5% or 10%. For 1% curtailment rate, the number of batteries being lower than for 5% or 10% cases is explained by different sizes of the installed capacities for all wind, PV and tidal such as to minimize the waste energy.

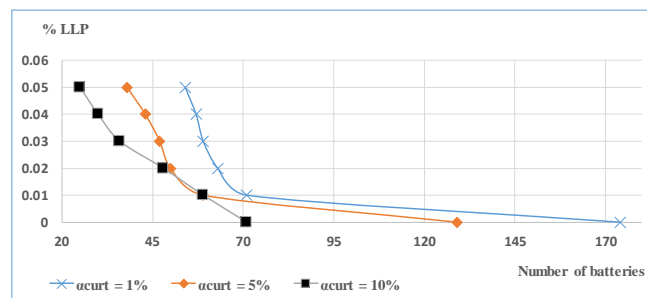


Fig. 4 Impact of loss of load probability on the optimal number of batteries for different values of curtailment rate

4) Scenario Reduced Curtailment with Thermal Generation

Reducing both the system cost and the curtailment rate can also be achieved by admitting the contribution of a certain level of installed capacity of thermal generation in the energy mix. The French Pluriannual Energy Plan [4] targets *almost* 100% renewables on the Ouessant island, but without any mention to precise figures. In general, any stand-alone system needs operating reserves such as to reduce the risk of power shortage, and these options are storage based or thermal generation. In this scenario, the optimization procedure returns next the optimal generation mix under a double constraint, of having limited share of thermal generation for guaranteeing the system reliability, and constraining the curtailment rate. Results in terms of costs are presented in table V.

TABLE V TOTAL SYSTEM COST AT DIFFERENT THERMAL SHARES AND CURTAILMENT RATES (M€)

Curtailment rate (%)	Thermal generation share (%)	
	5%	10%
1%	60.9	57.1
10%	33	23.5

Results show that admitting shares of thermal generation in the power mix, and thus reducing the target set on carbon emissions, leads to a cost of energy close to the one obtained with 1-2% LLP. For the same orders of magnitude of the system cost as in optimal scenario, it is ultimately possible to reduce the system oversizing while reconsidering the CO₂ emission objective. Solutions such as demand side management, storage with batteries and dispatchable generators such as biomass or diesel seem all feasible, yet imperfect substitutes in terms of cost.

V. CONCLUSION

This study has investigated the optimal size of hybrid systems composed of PV, wind and tidal energy and storage installed on the French Atlantic island of Ouessant for energy planning in 2030. Beyond the infrastructure design, the key issue is the evaluation of the load management options that reduce the power curtailment arising from oversizing the power plants on a small-scale island. Three main options seem realistic: installing energy storage, keeping some thermal generation shares and applying demand management measures. Several optimization criteria are used to compare potential solutions: cost minimization, loss of load probability and thermal generation thresholds.

Results show that 100% renewable scenario would cost 22 M€, out of which batteries represent more than 55%. The energy curtailed is significantly high, i.e. 53.8% of the renewable potential. Accepting locally events of unmet load over the year significantly decreases the system cost, irrespective of the energy rate in excess. Targeting small rates of curtailment comes with costs: for example, 1% of curtailment and 0% unmet load are reached for 171 M€. Yet accepting 1% unmet load decreases the cost by almost 60%.

Irrespective of numbers, the method could apply to other islands and remote locations, by accurately accounting for the curtailment criterion while optimally planning the local energy mix (seen an application to another island in [21]). Otherwise, with no economic consideration for the power lost, the model selects oversizing the system meaning that the natural power inflows (wind, solar and tidal) have no economic value. It is also shown that admitting fossil fuels during some hours over the year, with their consequently carbon emissions and energy dependency inconvenients, might be part of the solution to punctually generate 100% renewable power over the year. This solution alone could reduce the high cost of 100% renewables in terms of curtailment and power storage.

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