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Cost-optimal electricity systems with increasing renewable energy penetration for islands across the globe

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HIGHLIGHTS

- Levelized system costs decreases considerably with increased penetration of renewables.
- Cost-optimal systems occur in range of 40–80% renewable penetration.
- Renewable penetration of 60–90% achieved at no additional cost from current prices.
- Batteries become favorable storage option when initial costs reduce by 50–70%

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ABSTRACT

Cost-optimal electricity system configurations with increasing renewable energy penetration were determined in this article for six islands of different geographies, sizes and contexts, utilizing photovoltaic energy, wind energy, pumped hydro storage and battery storage. The results of the optimizations showed strong reasoning for islands to invest in renewable energy technologies (particularly wind energy), as compared to conventional power generation. Levelized cost of systems for electricity generation decrease considerably with increasing renewable energy penetrations, to an optimal point in the range of 40–80% penetration. Furthermore, renewable electricity integration in the order of 60–90% could still be achieved with no added cost from the initial situation. Cost increases after these optimal points are attributed to the growing inclusion of storage, required to meet the higher renewable energy shares. However, with battery costs forecast to fall in the coming years, and a cost reduction of 50–70% already causing lithium-ion batteries to overtake pumped hydro as a cost-favorable storage option in this model, there is a real case for islands to begin their transition in a staged process; first installing wind and PV generation, and then - as storage costs decrease and their renewable energy capacities increase - investing in storage options.

1. Introduction

The proliferation of sustainable energy technologies is growing at a steady rate [1], as society embarks on the colossal, yet imperative process of undertaking a paradigm shift, from default dependence on fossil fuels, to new systems, built on renewable resources. Geopolitical tensions, as a result of dependence for energy imports, climate goals and national contributions agreed upon at the COP21 in Paris, increasing concerns for the environmental impacts associated with fossil fuel extraction and use, and the opportunity for individuals to act as energy producers, are all factors driving this growth. Furthermore, as deployment rises and manufacturing costs for sustainable technologies fall, the economic equation is increasingly favoring renewable energy technologies [2,3].

A large number of small islands around the world are currently almost exclusively dependent on imported diesel and other oil products to meet their energy needs. Diesel and heavy fuel oil (HFO) generation are the primary methods used for electricity generation on these islands. The smaller scale of electricity production and the volume and logistics of supply on islands, results in very high comparative electricity costs. These high costs, coupled with oil price volatility, desire for energy security, and the relatively higher vulnerability of islands to the impacts of climate change, build a strong rationale for islands to shift towards sustainable energy systems.

Most islands with substantial populations (greater than 10,000 people) possess a range of abundant renewable energy resources with high technical potential that can assist in this shift. While this is starting to happen with the more mature technologies of wind and solar

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photovoltaic (PV) energy, the door remains open for more novel technologies, such as wave, tidal and ocean thermal energy techniques, as well as geothermal, biofuels, concentrated solar power (CSP) and concentrator photovoltaic (CPV), to compete. Consequently, islands provide a unique and appropriate test bed for the research and development of such technologies [4]. A number of island governments have also set ambitious targets for achieving sustainable energy integration (many aiming for 100%), however widespread progress is still limited to date, for a variety of reasons, ranging from the technical to the social and political realms. An important question is: how can the optimal use of renewable energy resources on islands be achieved within the context of full analysis of their electricity systems?

The objective of this article is to compare cost-optimal renewable electricity system configurations for different islands with PV, wind and diesel generation, and battery and PHS storage technologies, and determine how system costs and configurations vary with increased penetration of renewables.

1.1. Accomplished research

There is a growing body of research into the topic of optimal renewable energy configurations for island systems, which has predominantly focused on wind, PV, and hydropower as generation technologies, coupled with battery, pumped hydro and a few utilizing hydrogen as storage options. Overview studies on the energy situation and the development of renewables are presented by [5–7]; renewable energy is typically in an early stage of development, but opportunities are considered very significant.

Several articles present methodologies for performing hybrid renewable electricity system optimizations - as well as many applying them to specific case studies - based on various criteria. Net present value (NPV) or levelized cost of energy (LCOE) were the most commonly used economic optimization criteria [8], and optimal systems based on these were investigated in [9–18]. Other, more system performance-based criteria have also been adopted for optimization, namely loss of load probability (LOLP), loss of power probability (LOPP), loss of power supply probability (LPSP) and load coverage rate (LCR). It is explained in [19] though, that these constraints are usually evaluating effectively the same thing, ensuring system reliability. A number of articles [9,18,20–23] determined ‘optimal systems’ by identifying the best performing system among a specified range of proposed options, rather than by solving a pure optimization problem.

A further group of articles have concentrated on approaches for solving the more complex optimization problems posed by hybrid renewable energy systems, as a result of multi-criteria optimization objectives, often with non-linear, non-convex natures. These focus on the various optimization algorithms and techniques. Overviews of existing research and future developments concerning the use of optimization algorithms for design, planning and control problems in the field of renewable and sustainable energy are presented in [8,19,24–26].

The majority of the literature has concentrated on single case-studies, with only a select few analyzing multiple islands, from the same island group: Seven Greek islands were investigated in [27]; three Japanese islands in [12]; three Greek islands in [28]; and the Canary Islands [29]. However, none of these papers compared different islands from across the world. The notable exception is [30], where the optimized configuration including solar PV, wind power, and battery storage into the power supply system was determined for a large number of islands based on GIS. In addition, Ioannidis et al. [5] classify islands regarding several qualitative metrics.

All papers presented here focus on the analysis for each island of one single renewable energy configuration or a few configurations; others provide the single optimum solution. However, in real life a new energy system on an island is not determined in one step, but gradually develops from a small contribution of renewable energy to large penetration of such sources.

Therefore, in this article we will investigate how the optimum configuration and costs of renewable energy systems on islands change with increasing penetration of renewable energy sources. We will do that for a spread of islands across the world, focusing on 6 case studies. We use hour-by-hour simulation of the electricity production system and apply a Sequential Quadratic Programming (SQP) Algorithm using gradient descent to find the optimum system given a certain penetration of renewable energy.

In this article, we first present the selected case study islands (Section 1.2). Subsequently, the methodology and input data are described (Section 2). Next the optimization results are presented (Section 3). We finalize with discussions (Section 4) and conclusions (Section 5).

1.2. Case studies

An overview was compiled of all islands in the population range of 10,000 to 1,000,000, totaling 300. From this group, six islands were selected as case studies for this analysis. We used the following criteria for selection: (i) no connection to a mainland grid; (ii) fair representation of the different geographical water bodies, population sizes and island land areas; (iii) preference for islands with serious renewable energy ambitions, and (iv) data availability. This lead to the selection of islands described below.

Streymoy is the largest island of the Faroe Islands, and lays isolated in the North Atlantic Ocean, between Norway, the United Kingdom and Iceland. The island is quite mountainous, particularly in the northwest corner and has a sub-polar oceanic climate, with average monthly temperatures of 3.4 °C in the winter and 10.6 °C in the summer.

Aruba is an island located in the southern part of the Caribbean Sea, around 30 km north of the coast of Venezuela, and is a constituent country of the Kingdom of the Netherlands. The island is relatively flat and river-less, with white sandy beaches on its western and southern coasts, protected from the strong ocean currents that affect the northern and eastern coasts. It has a tropical semi-arid climate, and unlike most of the Caribbean region is more dry and arid. The average monthly temperature varies within a narrow range between 26.7 °C and 29.2 °C, responsible for a steady constitution of tourists among its population.

Sumba is an island located in the eastern section of the Indonesian Archipelago, west of West Timor and around 700 km north of Australia. The landscape consists of lower hills unlike the steep volcanoes found on many other Indonesian islands. It has a semi-arid, quite dry climate compared to the rest of Indonesia, where the dry season lasts for between eight and nine months while the wet season only lasts for around three to four [31]. The average monthly temperature varies between 22.3 °C and 30.7 °C.

Rhodes is the largest of the Greek Dodecanese islands, in the Mediterranean Sea, around 18 km from the southern shore of Turkey. It has a quite mountainous and forested interior, while also being home to long stretches of pristine beaches along its expansive coastline, making it one of the most popular islands for tourism in Greece. It has a hot-summer Mediterranean climate, with the average monthly temperature ranging from 13 °C in the winter to 27 °C in the summer.

Gran Canaria is the third largest of the Spanish Canary Islands, situated in the Atlantic Ocean around 150 km west of the coast of Morocco. It is renowned for its variety of microclimates: it is generally warm; although inland the temperatures are quite mild, with occasional frost or snow in the winter. Due to the different climates and variety of landscapes found, with its long beaches and white sand dunes contrasting with green ravines and small villages, the island is a popular tourist destination. The average monthly temperature ranges from 17.9 °C in January to 24.6 °C in August.

Rarotonga is the largest and most populous island of the Cook Islands, lying in the South Pacific Ocean around 3000 km north east of New Zealand. It is surrounded by a lagoon, and agricultural terraces, flats and swamps surround the central mountainous area. The islands typically have a tropical oceanic climate, with a wet season from

Table 1
General Island data and electricity system details.

Island	Population	Area (km^2)	Population density (ppl/km^2)	Electricity demand energy (GWh)	Yearly electricity consumption per capita (kWh/person)	Mean demand (MW)	Peak demand (MW)	Electricity selling price ($US/kWh)
Streymoy	22,400	373	60	142	6356	16	25	0.26
Aruba	103,400	179	578	910	8801	104	122	0.25
Sumba	685,186	11,153	61	41	60	5	7	0.07
Rhodes	115,490	1401	82	852	7377	97	213	0.20
Gran Canaria	838,397	1560	537	3384	4036	386	548	0.13–0.18
Rarotonga	11,500	67	157	27	2312	3	4	0.44

December to March, and a mild dry season from April to November. The average monthly temperature varies very little, between 23 °C and 27 °C.

Shown below is Table 1 summarizing the general island information and their respective electricity system details.

2. Methodology – input data, modelling and optimization approach

In order to determine cost-optimal electricity system configurations, the hourly electricity production from solar PV, wind, diesel, pumped hydro storage (PHS) and battery storage was required to be simulated. This was achieved by modelling their hourly production in MATLAB/Simulink. In this section, we will first discuss the input data, followed by the method for modelling each technology, and finally the optimization details.

2.1. Input data/Resource assessment

The simulation is based on the following (hourly) inputs, for a period of one year:

- Solar Irradiance (W/m^2)
- Ambient Air Temperature (°C)
- Wind Speed at turbine hub height (m/s)
- Electricity Demand (W)
- Assumed available head height for pumped hydro system (m)

The hourly solar irradiation data was obtained from the Meteonorm database. As stated in the General Assumptions section, real irradiation data was not available from any of the islands investigated, so the synthesized irradiation data from Meteonorm was the best available option. Shown below in Fig. 1 is the monthly averaged irradiation per day. Note that total global horizontal (Gh) irradiation was used in the model.

Sub-hourly, measured wind data was obtained from weather stations located on each of the islands, using the Integrated Surface Database (ISD) provided by the National Center for Environmental Information's National Oceanic and Atmospheric Administration (NOAA) [NOAA]. The sub-hourly data was averaged in hourly time intervals, with missing measurements filled with the average of the preceding and following real measurements. Note that these measurements are taken at the altitude of the weather station and need to be corrected to the hub height in order to calculate their power output. This correction was performed using the common log wind profile law:

$$V(z) = V_{ref}\left(\frac{ln\left(\frac{z}{Z_0}\right)}{ln\left(\frac{z_{ref}}{Z_0}\right)}\right)$$

V (z) - Wind speed at Hub Height, z [m], V_{ref} - Wind speed at measurement height [m/s], z - Hub Height (m), z_{ref} - Measurement height at weather station [m], Z_0 - Surface Roughness Length [m].

Shown below in Fig. 2 is the monthly average wind speed for the selected islands.

The head height of the theoretical PHS system was assumed to be equal to half of the highest elevation on that island. The magnitudes of the PHS system head heights are shown in Table 2 below.

2.2. Modelling

A simple control logic is implemented, to prioritize production from renewable sources and allow them to meet demand where possible. When the renewable capacity is unable to meet demand, it is first checked to what extent the pumped hydro system has the capacity to do so, then in turn the battery, and finally, the remainder is requested of the diesel generators. The storage technologies can only provide electricity to within their own defined limits, detailed ahead in this section. In the case that the total generation capacity in any hour is unable to

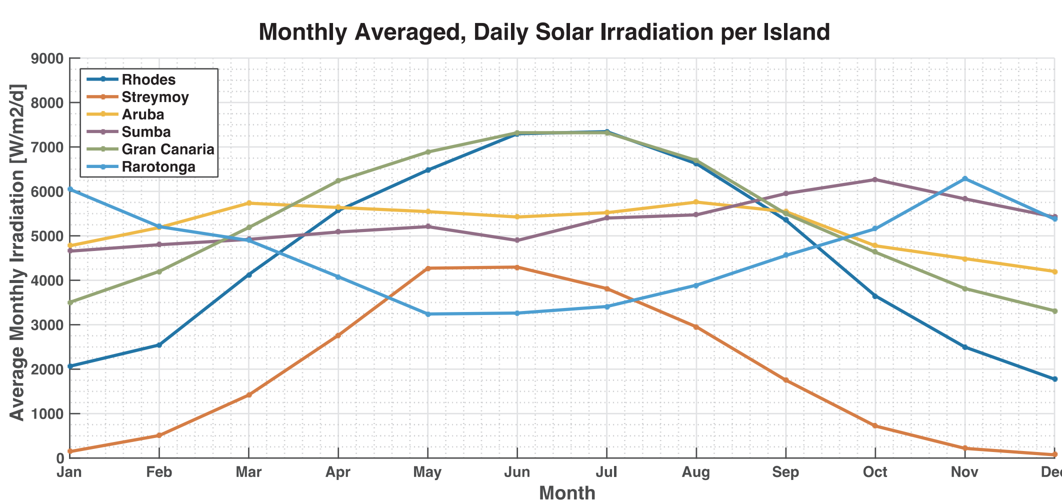

Fig. 1. Solar Irradiation for selected islands.

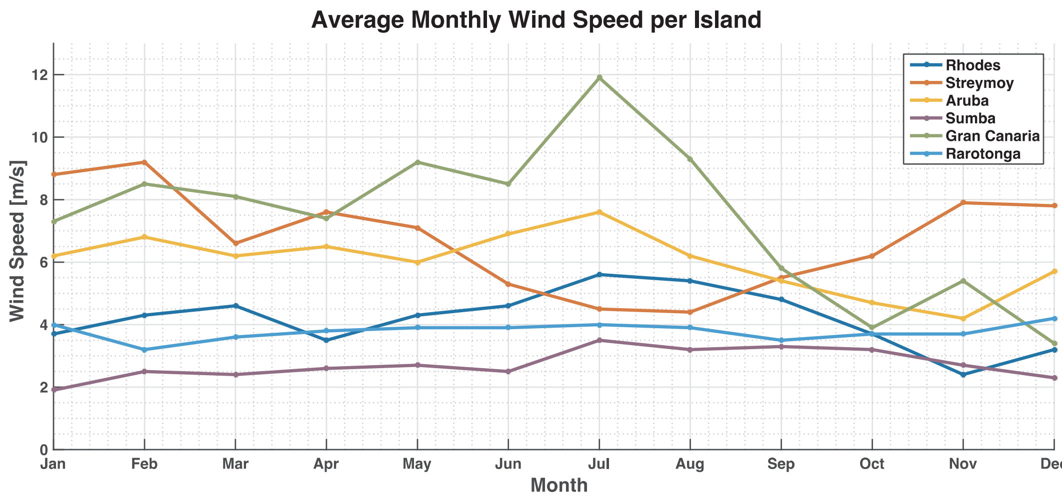

Fig. 2. Average Wind Speeds for selected islands.

Table 2
PHS system head height on islands.

Island	Highest elevation (m)	PHS height (m)
Aruba	189	94.5
Sumba	1225	612.5
Rhodes	1216	608.0
Gran Canaria	1949	974.5
Rarotonga	652	326.0
Streymoy	789	394.5

meet the requested demand, the remainder is categorized as 'unmet demand'. Conversely, when there is a greater production from renewables than demand, the difference between the demand and (over-) production is categorized as 'curtailed' energy. It is important also to note that the system is built up from a zero installed capacity starting point, or a 'greenfield' situation, not considering the current installed capacities of generation and storage technologies already on the islands. This was done since the objective was purely to determine the optimal system, rather than building on top of what is already there.

The production from solar PV, wind, diesel, pumped hydro storage (PHS) and battery storage were modelled according to the following equations [32–34]:

2.2.1. Solar PV

$$P_{PV}(t) = A_{PV}\cdot G(t)\cdot \eta_{PV}(t)\cdot \eta_{inv}\cdot \eta_{MPPT}\cdot \eta_{other}$$

$$\eta_{PV}(t) = \eta_{Tref}\cdot[1-\beta_{ref}(T_C(t)-T_{ref})]$$

$$T_C(t) = T_{amb}(t) + G_t(t)\cdot e^{a+b\cdot WS(t)}$$

Where

η_{inv} = 0.95 [35]
η_{MPPT} = 0.98 [32]
η_{other} = 0.97 [36]
η_{Tref} = 0.15 [34]
β_{ref} = 0.0041 [34]
a = − 2.98 [34]
b = − 0.0471 [34]
$P_{PV}(t)$ - Instantaneous AC power production at time, t [W]
A_{PV} - Area of PV [m^2]
G(t) - Irradiance on module at time, t [W/m^2]
$\eta_{PV}(t)$ - PV efficiency at time, t
η_{inv} - Inverter efficiency
η_{MPPT} - PV Maximum Power Point Tracker efficiency
η_{other} - Other efficiency losses: mismatch between modules, ohmic cable losses, soiling
η_{Tref} - Module reference efficiency at reference temperature and 1000 W/m2 irradiance
β_{ref} - Temperature coefficient [K^{-1}]
$T_C(t)$ - PV cell temperature at time, t [K]
T_{ref} - Reference temperature [K]
$T_{amb}(t)$ - Ambient temperature at time, t [K]
$G_t(t)$ - Solar irradiation on panel at time, t [W/m^2]
a - Experimental coefficient for high radiation and no wind [dim]
b - Experimental coefficient accounting for the wind effect on cell temperature [dim]
WS(t) - Wind speed at time, t, at a standard altitude of 10 m [m/s]

2.2.2. Wind

The conversion from wind speed to electric power was modelled using the power curve of a Gamesa G87-2.0 MW turbine [37]. For use in the model, a hub height of 78 m (4 sections) [37] was selected.

2.2.3. Diesel

Electricity production via diesel generators was modelled as a dispatchable resource, with the diesel generators able to provide any amount of electricity required, up to its installed/rated capacity. The output-dependent efficiency of the diesel generators was not considered, and though relevant, it is of less importance for smaller island electricity systems, as they almost always have multiple generators that can be switched off to match supply and demand and avoid them running on low partial loads. Instead of using output-dependent efficiencies, average fuel costs of generation were determined per island by identifying the financial investments in fuel for electricity generation (via the financial reports of the producers shown below in Table 3) and the amount of electric energy produced from the generation. We see that there is considerable variation, which may be explained by

Table 3
Fuel costs for diesel electricity generation per island.

Island	Year	Annual production from diesel (GWh)	Annual fuel expenses ($US)	Fuel cost ($US/MWh)	Reference
Streymoy	2014	150	25,416,000	169	[50]
Aruba	2011	838	183,010,305	219	[51]
Sumba	2013	21	6,000,000	282	[52]
Rhodes	2010	–	–	220	[53]
Gran Canaria	2015	–	–	110	[54]
Rarotonga	2014	27	7,296,201	267	[55]

transportation distances, fuel volumes used, and monopoly positions.

Since the model operates with hourly time steps, the rate-limited ramping behavior of diesel/oil-based generator(s) are not captured, as this is only relevant for shorter time scales. Hence, no rate-limiting factor has been included in the model.

2.2.4. Battery

Lithium-ion battery technology has been selected for implementation in this model. Modelling the performance of a battery over the course of its life is a complex task, and it can be performed in high detail with regard to its chemical behavior and its subsequent influences on the cell voltage and current, as well as the influence of other factors such as temperature, charge/discharge rate and depth of discharge (DoD). For this analysis a basic battery model has been developed, simplifying the voltage and current relationship present in battery charging and discharging by relating the charge rate with the state of charge (SOC). Furthermore, the effects of charge/discharge rates and depth of charge/discharge on battery life have not been incorporated. It is also assumed in this model that the battery system is operated in ideal constant conditions of 20 °C, as batteries achieve optimum service life when used at 20 °C [38].

The maximum charging rate of a battery decreases with increasing SOC. An approximation of the SOC during charging has been made according to [39], shown in Fig. 3, and used to represent the charging behavior of the battery in a simplified way. Consequently, the battery can be fully charged in 3 h, and the maximum SOC that can be reached after hours 1, 2 and 3 of charging are 80%, 95% and 100%, corresponding with maximum charging rates of 0.8 C, 0.15 C and 0.05 C respectively. The ‘C-rate’ is a measure of the rate at which a battery is theoretically charged/discharged, relative to the capacity of the battery. A 1 C charge rate for example, would fully charge the battery in 1 h, a 0.5 C rate in 2 h, and so on. Naturally, when charging at a lower rate than the corresponding maximum charging rate, the time taken to fully charge the battery is longer. Fully charging the battery to 100% has been permitted in the model.

For discharging, the relationship between the SOC of the battery and the maximum possible discharge rate however can be fairly well approximated as a linear relationship, provided that the SOC is kept above the point at which the voltage (and consequently the SOC) rapidly drops off. Furthermore, batteries are prone to self-discharging, and Lithium-ion batteries are known to self-discharge at a rate of approximately 2–3% of the maximum capacity per month [40]. A self-discharge rate of 2.5% per month has been incorporated into the battery model, scaled linearly per hour. A DoD limit of 90% (minimum SOC of 10%) has been used in the model.

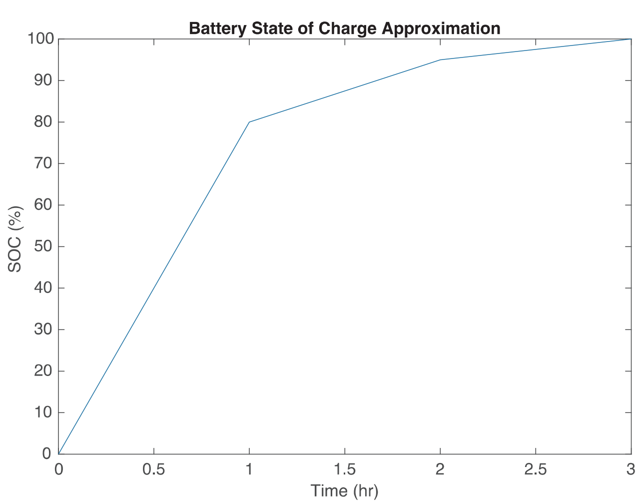

Fig. 3. Approximation of the maximum state of charge behavior over time, during charging.

It was determined in a study on estimation of the state of charge and state of health of Lithium-ion batteries, that at a discharge rate of 1 C, the battery capacity is marginally reduced, by 1.8% of its nominal capacity [41]. A maximum discharge rate of 1 C has been used in the model, as since the simulation model runs with one-hour time steps it is therefore not possible to draw an amount of energy from the battery in one hour that is greater than the battery’s capacity, i.e. it is not possible to exceed a 1 C discharge rate. Consequently, the battery’s nominal energy capacity [in Wh] has been reduced by a factor of 1.8% to represent the functional total discharge capacity. In the model, a charge efficiency of 100% has been assumed, and the discharge-rate dependent efficiency of 98.2% is used, giving the battery a total efficiency of 98.2%.

2.2.5. Pumped hydro storage (PHS)

The pumped hydro storage system is modelled according to the following equations, with the respective efficiencies sourced from [42]:

When producing power:

$$P_{gen}(t) = \rho_w \cdot g \cdot H \cdot q \cdot \eta_t \cdot \eta_g \cdot \eta_{tr},$$

where $\eta_t = 0.90$, $\eta_g = 0.95$ $\eta_{tr} = 0.987$.

When pumping water for storage:

$$P_{st} = \frac{\rho_w \cdot g \cdot H \cdot q}{\eta_t \cdot \eta_g \cdot \eta_{tr}}$$

where $\eta_p = 0.74$, $\eta_m = 0.96$, $\eta_{tr} = 0.990$

$P_{gen}(t)$ - Instantaneous turbine AC power generation at time, t [W]
ρ_w - Density of water [kg/m^3]
g - Acceleration due to gravity [m/s^2]
H - Head height [m]
q - Flow rate [m^3/s]
η_t - Turbine efficiency
η_g - Generator efficiency
η_{tr} - Transformer efficiency
η_p - Pump efficiency

2.3. Optimization

In order to optimize the system configuration based on minimized cost, specific constraints and the respective costs of the generation technologies are introduced, which together with the installed capacities as variables, allow for an objective function to be defined.

A well-established metric in the energy field for quantifying and comparing the costs of electricity generation technologies is the Levelized Cost of Electricity (or Energy) (LCOE). It is calculated by accounting for all of that technology’s (expected) lifetime costs (including investment, construction, financing, maintenance, fuel, taxes, insurance and incentives, and decommissioning), which are then divided by the total energy production over the course of its lifetime [43]. All cost and benefit values are adjusted for inflation and discounted to account for the time-value of money. This definition can be extended to include the levelized cost of storage, in order to assess the Levelized Cost of System (LCOS).

The LCOS incorporates both the costs of electricity generation and of storage, in order to give an indication of the total levelized cost of electricity supply systems. For this project, a simplified formulation was used, omitting the financing, taxes, insurance, incentives and any value that can be salvaged at the end of the life of the project. It should be noted, that this definition does not include costs associated with the conversion, transportation, and distribution of electricity, nor the power quality management services, which are also significant when considering all of the costs attributed to the reliable functioning of an electricity system. Nonetheless, the LCOS does serve as a useful basis for the comparison of various electricity systems.

The LCOS was formulated and implemented as follows in this project:

$$LCOS = \frac{\sum_{t=0}^{T} \frac{I_t + FM_t + VM_t + F_t}{(1+r)^t}}{\sum_{t=0}^{T} \frac{E_t}{(1+r)^t}}$$

I_t = Investment Cost in year t [USD/kW]
FM_t = Fixed Maintenance Cost in year t [USD/kW-year]
VM_t = Variable Maintenance Cost in year t [USD/kWh]
F_t = Fuel Cost in year t [USD/kWh]
E_t = System Energy Yield in year t [kWh]
T = Project Lifetime
r = Discount Rate

The system variables required to be optimized are:

IC_{PV} - The installed capacity of PV power [MW]
IC_W - The installed capacity of wind power [MW]
IC_{PHS} - The installed capacity of the PHS turbine/pump power [MW]
$IC_{res,up}$ - The installed energy capacity of the PHS system upper reservoir [m^3]
$IC_{res,low}$ - The installed energy capacity of the PHS system lower reservoir [m^3]
IC_B - The installed energy capacity of the battery system [MWh]
IC_D - The installed capacity of diesel generators [MW]

2.3.1. Objective function

Following from the LCOS construction, the objective function was formulated as below. The objective function takes the form of a linear programming problem. The goal of the optimization is to minimize the objective (cost) function, while meeting the specified constraints stated below.

$$LCOS = \frac{\frac{\sum_{t=0}^{T} IC_X(I_X)_t + IC_X(FM_X)_t + E_{x,t}(VM_X)_t + E_{x,t}(F_X)_t + IC_Y(I_Y)_t + IC_Y(FM_Y)_t + \cdots}{(1+r)^t}}{\frac{(E_{S,prod})_t}{(1+r)^t}}$$

- Investment costs are applied in [USD/installed kW] for production elements and [US- D/installed kWh] for storage elements
- Fixed maintenance costs are applied in [USD/kW-year] for production elements and [USD/installed kWh-year] for storage elements
- Variable maintenance costs are applied in [USD/kWh produced] for production elements and [USD/kWh produced] for storage elements
- Fuel costs are stated in [USD/kWh produced], only valid for production elements

2.3.2. Constraints

The objective function is subject to the following constraints:

$IC_{PV}, IC_W, IC_{PHS}, IC_{res,up}, IC_{res,low}, IC_B, IC_D \geq 0$

$E_{d,unmet} \leq 0.001 \cdot E_{d,total}$
$E_D = \gamma \cdot E_{S,prod}$
Where $\gamma = 0.1, 0.3, 0.5, 0.7, 0.9$

All variables were logically subjected to the constraint of being greater than or equal to zero.

Additionally, constraints were placed on the unmet demand energy ($E_{d,unmet}$), and diesel penetration (E_D) at intervals of 20% of the produced system energy ($E_{S,prod}$). In this context, the produced system energy is defined as the total electricity demand ($E_{d,total}$) minus the unmet demand energy.

The unmet energy demand was restricted to less than 0.1% of the total electricity demand for this 'ideal' simulation model. Of course, in practice, the goal is always to have demand met at all times, but due to changes from year to year and unplanned availability/system failures, the unmet demand can increase beyond the limit set, especially in cases where there are limited backup generation reserves. Renewable energy penetrations of 10%, 30%, 50%, 70%, and 90%, of the produced system energy were investigated.

2.3.3. Optimization method

In order to find optimal solutions to the objective function, the 'Response Optimization' tool was utilized within the Simulink model [44]. The gradient descent method was implemented, with a Sequential Quadratic Programming (SQP) Algorithm. This selection was suitable for handling the 'continuous' signals and cost function produced in the Simulink model, as the Pattern Search and Simplex Search methods could not deal with these adequately. The gradient descent method uses the function fmincon, "a gradient-based method that is designed to work on problems where the objective and constraint functions are both continuous and have continuous first derivatives," [44]. The parameter tolerance, constraint tolerance and function tolerance were all set to $1e-3$ in the Optimization Options.

The data used for the Investment (I), Fixed Maintenance (FM), Variable Maintenance (VM) and Fuel (F) Costs are shown in Table 4.

3. Results

The optimizations returned a number of interesting results. Fig. 4 shows that as the renewable energy penetration is increased, the levelized system costs (LCOS) for electricity generation decrease considerably up to an optimal point in the range of 40% (in the case of Sumba), to 80% (in the case of Aruba).

Beyond the minimum LCOS points, the ability for PV and wind to meet higher shares of the electricity demand directly is strained, and the requirement for storage becomes essential - associated with the increasing LCOS. Despite this increase, renewable electricity integration in the order of 60–90% can still be achieved with no added cost from the initial situation of 0% penetration of renewables.

A general trend can be observed in the system configurations and the amount of curtailed energy for the cost-optimal systems. The installed capacities of renewables range from 50% of total installed

Table 4
Cost data used in LCOS calculation and optimization.

Technology	Investment Cost		Fixed Maintenance Cost ($US/kW-year)	Variable Maintenance Cost ($US/MWh)	Fuel Cost ($US/MWh)	Reference
PV	1625	$US/kW	11.5	0	0	[56]
Wind	1475	$US/kW	37.5	0	0	[56]
Geothermal	5450	$US/kW	0	35	0	[56]
Diesel	650	$US/kW	15	15	*See Table 3	
*PHS Electro-mechanical equipment + O&M	370	$US/kW	6.5	0	0	[57]
PHS - Civil works	253	$US/kWh	0	0.3	0	[49]
Battery	1054	$US/kWh	11.5	0	0	[49]

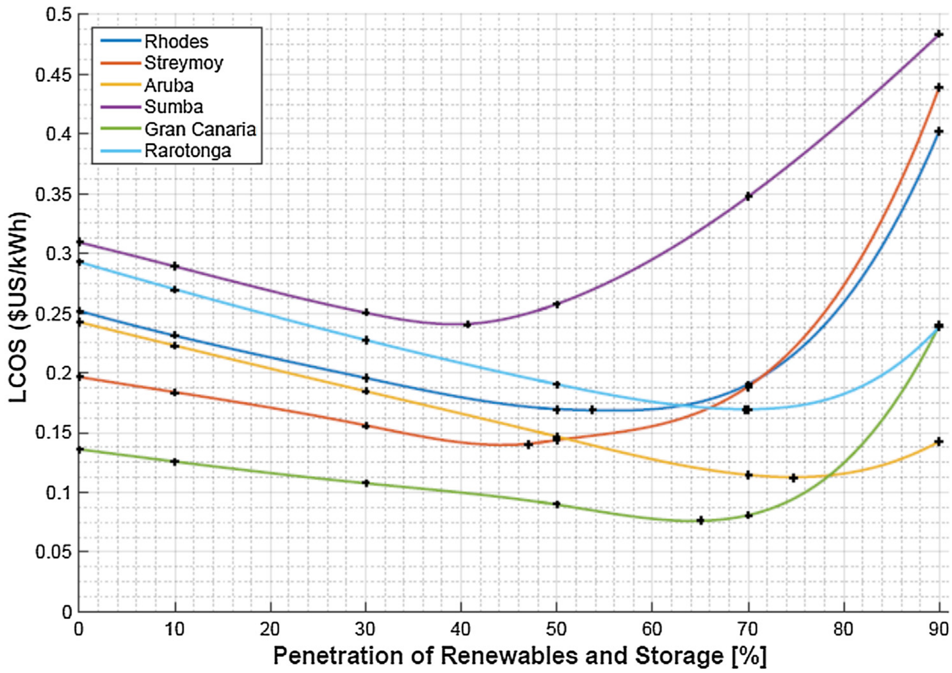

Fig. 4. Levelized Cost of System (LCOS) with increased renewables penetration.

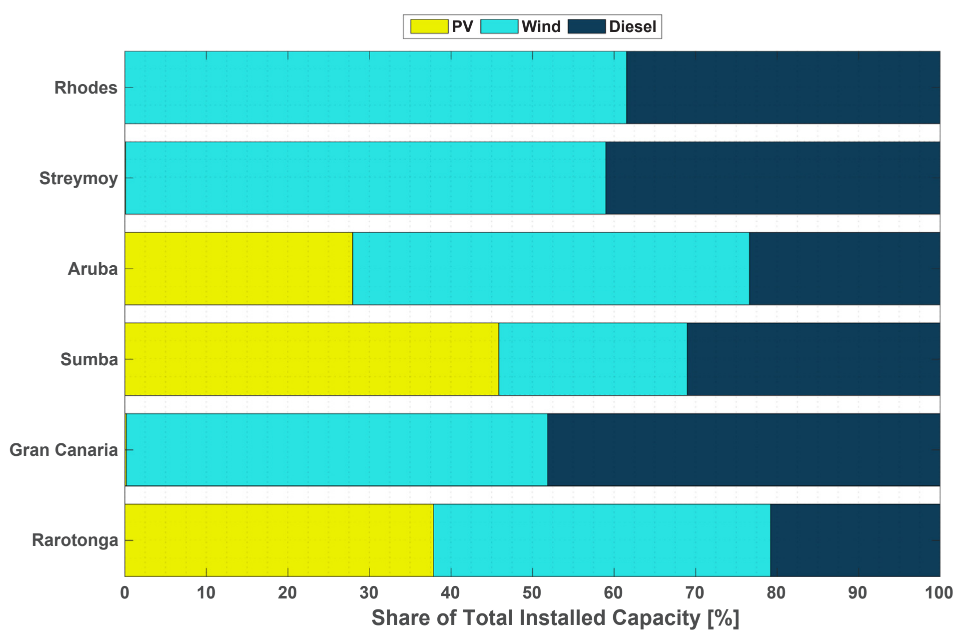

Fig. 5. Share in total installed capacity for the optimal system configurations.

capacity in Gran Canaria up to 80% in Aruba and Rarotonga, see Fig. 5. Also of interest, is the fact that none of the cost-optimal systems include any storage. As for the amount of curtailment, it emerges that all of the optimal systems require a moderate level of curtailment, varying in the range of 10% in Sumba and Gran Canaria up to 37% in Aruba.

Shown below in Fig. 7 are the installed capacities of PV, wind and diesel with increasing penetrations of renewables, as well as the average and peak electricity demands for the 6 islands. The installed capacities largely exceed the average and peak demands, due to the variable nature of the PV and wind generation. The capacity for the renewables to meet the electricity demands, and the need for generation reserves are addressed in Section 4. It can be seen below that the cost-optimal means of meeting the electricity demands as the renewable energy penetration is increased, is by first adding wind capacity. This is due to the fact that wind energy was the cheapest production method on all the islands except for Sumba. Increasing wind capacity was effective up to a critical point between 30 and 70% of renewable energy penetration, where the installed capacity of PV becomes more significant. This is explained by the fact that diesel penetration is limited, and wind energy alone - regardless of how many turbines are installed - cannot manage to meet the system electricity demand to within the specified limit of 0.1% of unmet demand, as there will always be periods of no wind. As a result, it consequently becomes effective to produce with PV (albeit at a higher cost than that of wind energy), also because there is a stronger correlation between the demand and PV production pattern, meaning that more of the PV energy is directly utilized. It is important to note also that these optimal systems are still requiring considerable amounts of curtailed energy, as seen in Fig. 6.

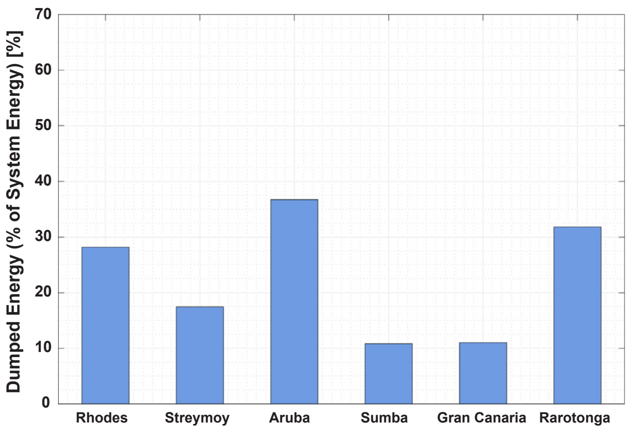

Fig. 6. Dumped Energy for Optimal System Configurations.

Increasing the renewable energy penetration further above 70% sees the need for storage become more significant, as the ability for PV and wind alone to meet the demand becomes strained, and the system costs increase due to the addition of storage.

Illustrated in Fig. 8 below, is the variation of the shares of renewables and storage with increased RES penetrations, for the 6 islands investigated. As can be seen, Sumba stands out as the only island with a significant contribution from the pumped hydro storage, and a curbing of its dumped energy at high penetration. This is attributed to the fact that the periods of no solar production are more strongly correlated with periods of no wind production in Sumba, than in any of the other islands. This means scaling up the PV and wind capacities as higher renewable energy penetrations are desired, makes little contribution to meeting demand at these times, and therefore the requirement for storage is more significant. Also of interest, was that the batteries were installed to meet very small storage demands (which are too small to be seen in the below figure), however as the storage requirements became more significant, the PHS became the favorable option. This is discussed further in Section 4.

As significant reductions in battery costs are expected, also a sensitivity analysis was made for the battery costs. It can be inferred from Fig. 9 that – at least for Rhodes - a reduction in the battery investment costs of between 50% and 70% sees battery storage become a more favorable storage than pumped hydro. A large amount of battery storage is also installed when costs are reduced by 90%, reducing the required capacity of wind installed. In reality, as islands transition to higher shares of renewable energy this will make it more likely that they opt for battery storage rather than PHS, due to their costs forecast to decrease in the coming years.

4. Discussion

4.1. Optimal systems

The optimal RES penetration range of 40–80% achieved is fairly consistent with results obtained in literature for island systems, with RES penetrations of: 55% in the Atlantic and Arctic Oceans, 64% in the Caribbean Sea, 40% in the Indian Ocean, 58% in the Mediterranean Sea, and 49% in the Pacific Ocean (all averages for their regions) [30], 61% on the Island of El Hierro [11], 55–60% on Dongfushan Island [45], 78%, 92% and 85% on the islands of Kithnos, Ikaria, and Karpathos respectively (including maximum RES penetration as an optimization criteria) [28], and 77% on a small island in China [46]. The LCOS range observed of $US 0.08–0.5/kWh ($US 0.076/kWh for Gran Canaria) is consistent with that seen on El Hierro of $US 0.07/kWh [11], although considerably lower than values obtained in other studies which were found, in the range of $US 0.7–1.4/kWh in [20,22,47]. Potential reasons for this difference are the reduction in PV and wind generation costs since those papers were published, the inclusion of costs for additional equipment such as power converters, and the inclusion of more expensive storage methods. Further cost reductions e.g. for PV and wind can be expected. Of course, this will impact the optimum configuration, moving to slightly higher optimum percentages of renewable energy penetration. However, curtailment and costs of storage will eventually limit much further increase. Further sensitivity analysis was carried out for other variables including PV investment costs, and conclusions were found to be robust.

4.2. Additional costs

An important consideration in this discussion is the additional costs associated with the production and actual integration of the produced renewable electricity into the island grids. Costs associated with sub hourly balancing like intra-hour drops of wind speed resulting in sudden losses of production for example – and power quality management due to the increased penetration of the more variable renewable sources – are not included in the LCOS. These smaller time scale concerns could require additional generation/storage capacity, like diesel, batteries, flywheel storage or demand response (see, e.g. [48]), that are able to maintain the smooth and reliable functioning of the system. These technologies however also come at a price, which would need to be added (as required) to the calculated LCOS. It was found however, that adding battery capacity for half an hour at peak demand only marginally increased the LCOS. The same is likely true for taking measures to maintain sufficient inertia in the power system, e.g. through adding idling generators. Additionally, it is likely that the installation of renewables on islands comes at an elevated price when compared to continental installations, due to the transport of required materials and equipment. Island-specific costs were used for the storage technologies, but continental values were used for the PV and wind production; though these continental prices are also likely to decrease in the coming years, partially negating the effect this might have.

4.3. Over-production and curtailment

Another important factor to consider is the large over-production of renewable energy present in each of the island systems examined. In the optimization, no costs/penalties were assigned to the curtailment of renewable energy, allowing for situations of large renewable energy over-production that are seen in the results. In the optimization process, it is evident that in order to meet the electricity system demand while limiting the diesel output, the optimization algorithm needs to find the cheapest way of meeting that demand given the constraints applied. As can be seen from the results, wind energy is favored as the preferred source for meeting the required renewable energy contribution, as it is the cheapest production method on every island usually in the range of $US 0.03–0.06/kWh, compared to that of PV at $US 0.08–0.11/kWh, and storage in the range of $US 0.8–2.0/kWh. Sumba is an exception where PV is cheaper than wind, and Streymoy another exception, where PV costs are around $US 0.22/kWh, double what is seen on the rest of the islands. The reason for the high levelized cost for PV on Streymoy is likely a combination of the fact it has the lowest average irradiation of all the islands, and the effects of not optimally tilting the PV panels, which results in less efficient production than seen at latitudes closer to the equator.

Another consideration for the high comparative price of the PHS relative to PV and wind, was that the round-trip efficiency for the PHS was around 59%, calculated according to efficiencies stated in a study on a hybrid wind and PHS system for the Island of Ikaria [42]. However, it is generally stated that round-trip efficiencies for PHS systems are usually more in the order of 70–80%, so the efficiencies selected are a little conservative - though our assumptions only very marginally increased the levelized cost of the PHS.

The fact that over-production and curtailment emerges as the

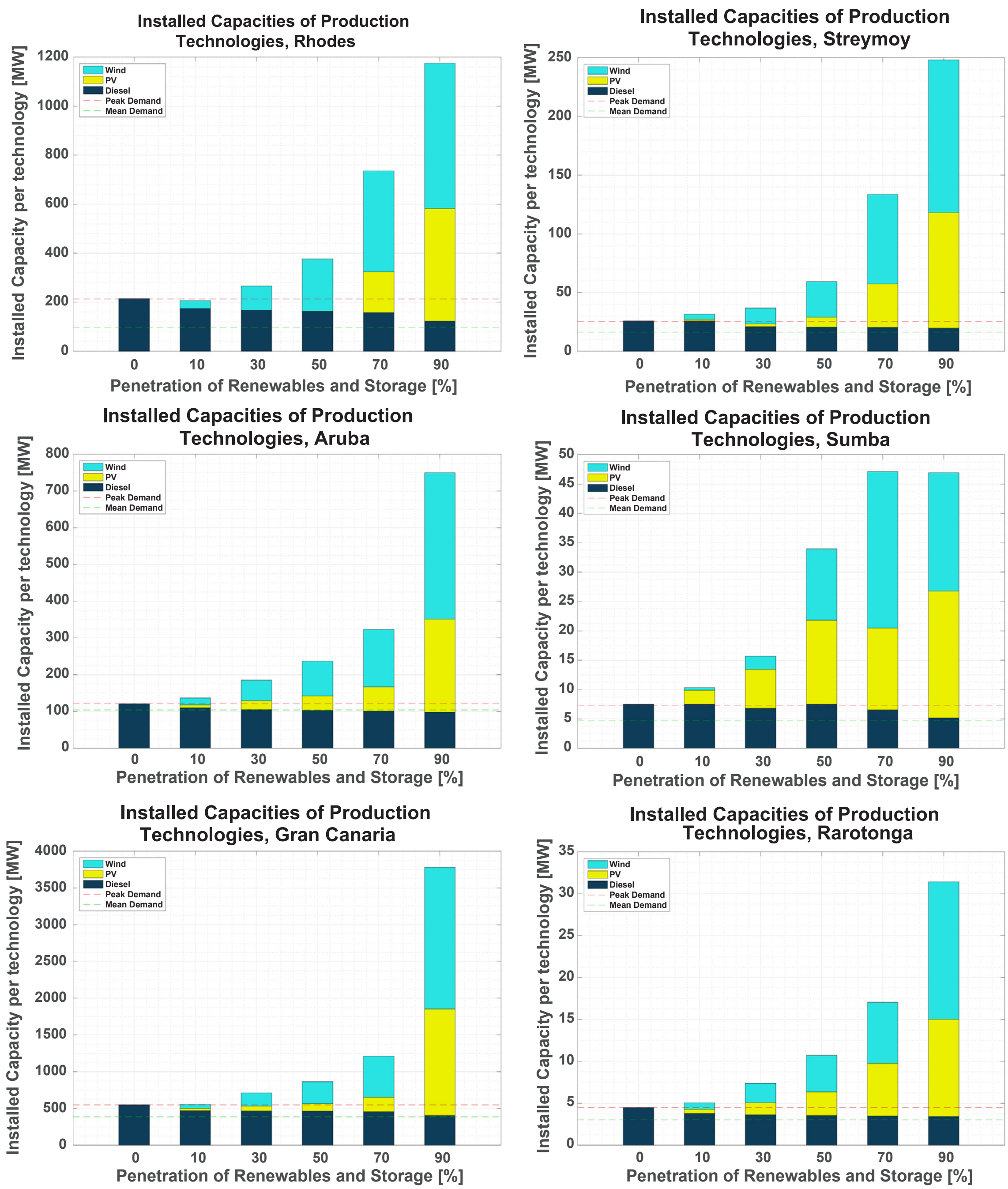

Fig. 7. Installed Capacities of Production Technologies with increasing penetration of renewables.

favorable option gives merit for investigation of additional, flexible uses for the energy that would otherwise be curtailed. Possible applications for islands could be: fresh water production by desalination since many islands also face issues in providing a sufficient fresh water supply, charging electric vehicles, or even hydrogen production as a means of storage coupled with fuel cells, or as a fuel for transportation.

4.4. The storage situation

A general trend was observed during the optimization where battery storage appeared favorable to PHS for very low-power demands. This can be explained by the generation limitations of the PHS, where the PHS system requires a minimum flow of 10% of its rated flow. Hence, as the installed capacity of the PHS system is increased, this minimum flow - and thus minimum power output - is increased, rendering the PHS system incapable of meeting power demands less than its rated minimum.

It also appeared that utilizing a combination of battery and PHS systems in considerable magnitudes was unfavorable. The possible reasons for this are:

- High comparative costs of storage opposed to renewable generation
- Diesel generation, being unlimited in magnitude and fairly cheap in its ability to meet the high peaks of the residual demand, would be reserved for that purpose. In doing so, the limited allowable diesel energy production is easily, quickly reached, necessitating that the storage be able to meet the lower magnitude residual demands of the system. PHS was usually found to produce at lower cost than battery storage, so it makes sense that a larger PHS system would be installed, restricting the possibility for a significantly sized battery

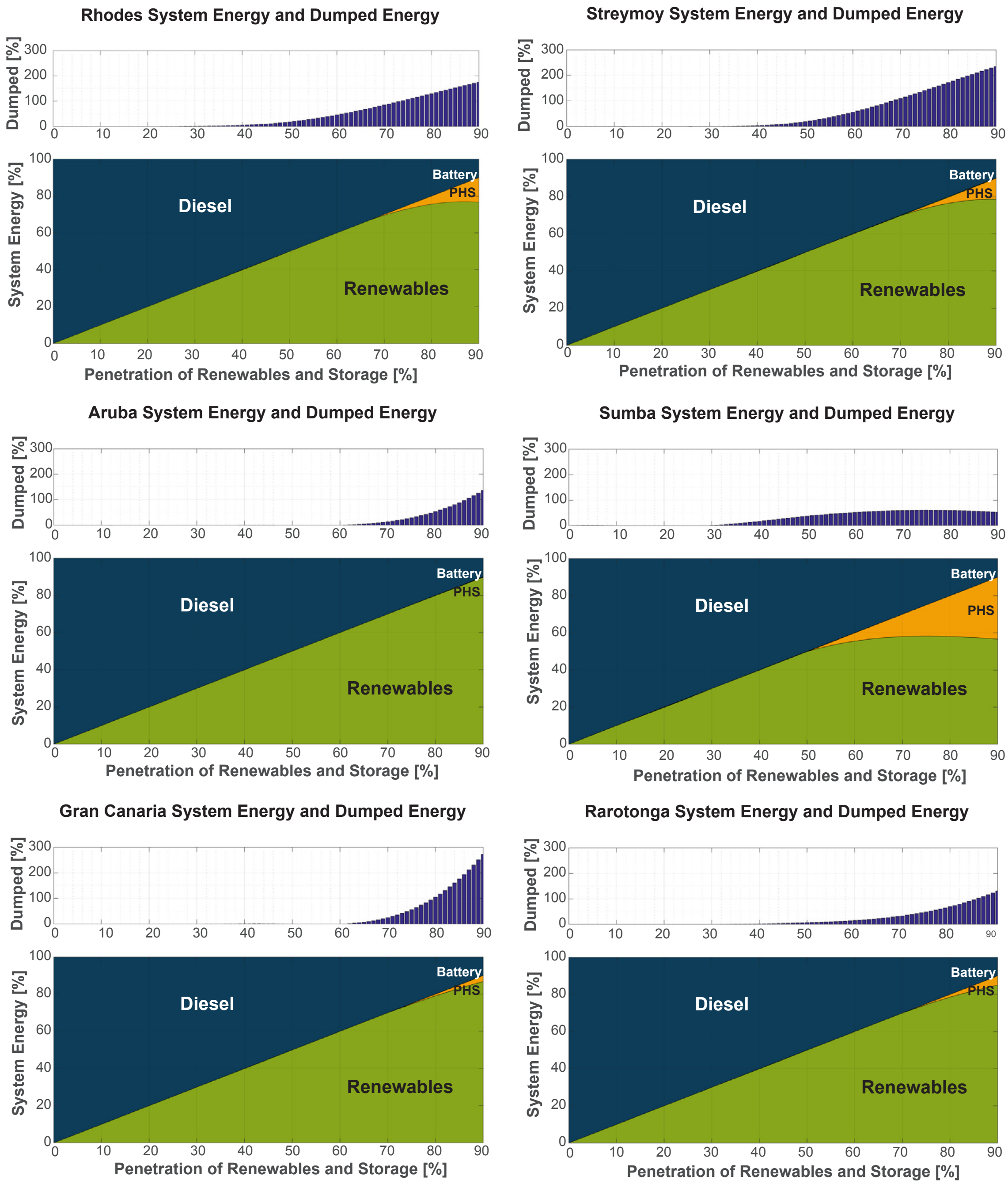

Fig. 8. Share of system energy met by diesel, directly by renewables and indirectly by storage (PHS and battery) technologies with increasing renewable energy penetrations, and dumped energy (above axis).

system to also be incorporated, as the system costs would swell.

- It is easier for the PHS to meet the high peaks since the turbine and reservoirs are sized separately, whereas the battery capacity would have to get very large just to meet the high, infrequent peaks.
- The PHS system was prioritized in the control logic to supply power ahead of the battery. Thus, the PHS will naturally provide more energy to the system even when the battery is able to, decreasing the economic viability a significant battery capacity.

The decision was made to model Pelton turbines for the PHS system. As a result of this, it was also assumed that the required pump costs were incorporated in the non-power generation portion of the PHS costs. Other turbine types also could have fulfilled the purpose of PHS power generation, such as the Francis turbine for example. In this case, since the Francis turbine can operate reversibly both as a turbine and pump, the pump costs would have inherently been incorporated in the power generation costs, and the previously mentioned assumption would not have been required.

4.5. Generation reserves

The optimal system configurations are determined for an ideal system, where the generation and storage technologies are available 100% of the time. As previously mentioned, due to changes from year to year in demand and renewable resource availability, and planned and unplanned unavailability, the unmet demand can increase beyond the specified limit set in the optimization. As a result, and the fact that the goal is generally to maintain a balanced system meeting demand at

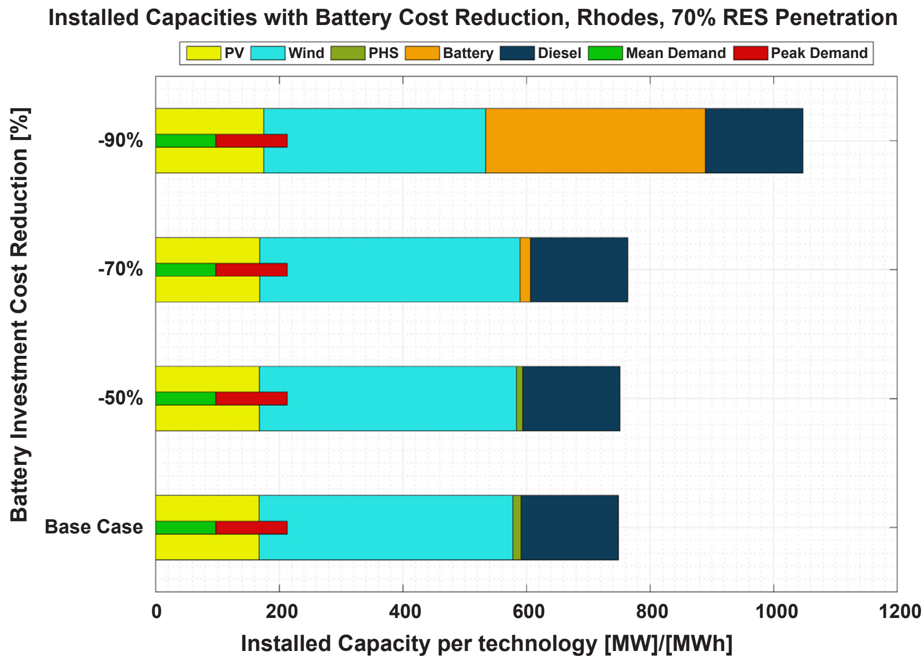

Fig. 9. System Configuration with Battery Investment Cost Reductions.

all times, either over-sizing the system or adding generation reserves may be necessary. Generation reserves were not considered in this project, and would increase the LCOS, but likely only to a small extent, particularly if diesel is selected as the back-up technology.

4.6. Global optimum

Because of the nature of the fmincon solver used - which terminates its search once a local minimum satisfying the optimization constraints is found - it is not possible to guarantee with certainty that global minimums were found in each of the optimizations performed. The fmincon solver is highly dependent on the initial starting point, and this was experienced in practice where local minima were returned from the optimization process, depending on how close to the 'real' global minimum the initial point was. In order to make every effort to ensure that global - rather than local - optima were returned, a range of initial starting points were experimented with in order to heuristically determine an initial configuration that was already close to satisfying the required constraints. Knowledge of the individual LCOE per technology was of great assistance in this process, as the technologies could be ordered by cost of production, and therefore it was understood which technologies should be prioritized and installed in larger capacities. Additionally, as an 'insurance' check, once the 'global' minimum was found, small variations to the system configuration were made to test the nearby points, in order to ensure that it was not possible to find a slightly more optimal system configuration. Weighing all of this up means that although possible, it is quite unlikely that even more cost-efficient configurations exist that are also able to satisfy the constraints in place.

4.7. PHS feasibility

The assumption that PHS is feasible on every island, with an achievable head height of half of the maximum elevation of the island is quite a crude one, and brings uncertainty to the actual cost-effectiveness of PHS. It is entirely possible that local site conditions may not allow for the construction of reservoirs with the head heights assumed in the model, likely altering the amount of storage installed and ultimately, the entire optimal system configuration. However, as mentioned, battery costs are set to fall to the point which they overtake PHS anyway and are feasible everywhere, so the storage contribution should remain.

4.8. Demand evolution

As mentioned earlier, the time frame for the modelling undertaken was a single year with hourly time-steps, using averaged power demands and resource data. Cost-optimal systems (based on LCOS) were determined under the assumption that the demand and production were constant for the entire lifetime of the system, however this neglects the fact that both the electricity demands, and renewable resource availability vary from year to year. Thus the optimal system in one year may be sub-optimal in the following year, depending on the demand and resource availability. Hence, performing this optimization over multiple years, or even just incorporating expected future demand developments (such as increased energy efficiency, demand changes due to electric vehicles, heat pumps, demand response, etc.), could allow for the provision of a system configuration that is cost-optimal over a duration closer to the system lifetime.

4.9. Other near-optimal configurations

It is likely that due to the number of variables, and the level of accuracy for which the optimal LCOS was determined, different system configurations could exist that fulfil the constraints at a quite comparable LCOS, while not strictly being an optimum. In this situation, a decision-maker should be aware of the various other configuration possibilities, and determine what the highest priorities are, consequently determining the most favorable configuration for their particular system. In any case, the renewable penetration is unlikely to be very different as can be seen from Fig. 4 where a clear optimal penetration exists, although the ratio of PV and wind installed capacities could slightly vary.

5. Conclusions

Islands have a genuine reason to invest in renewable energy technologies for their electricity generation needs. Levelized system costs for electricity generation decrease considerably with increasing renewable energy penetration, up to an optimal point in the range of 40% to 80%. At these optimal points, the system configurations predominantly comprise of a considerable portion of wind energy, in the order of 40 to 70%, coupled with diesel generation. Photovoltaic solar energy makes a significant contribution on only half of the islands.

Beyond the 40 to 80% optimal penetration point, the ability for photovoltaic solar energy and wind energy to meet higher shares of the electricity demand is strained, and large over-production occurs with the requirement for storage becoming more significant (associated with the increased levelized system costs) given the increasingly limited amount of diesel production permitted. Despite this increase, renewable electricity integration in the order of 60 to 90% of total system energy can still be achieved with no added cost from the initial situation of 0% penetration of renewables.

The relatively high costs of storage meant that significant over-production and curtailment of renewable energy was preferred over the implementation of storage. Battery storage appeared favorable to pumped-hydro storage for low-power demands, however the contribution of storage in general to the optimal system configurations only became pronounced at renewable penetrations of greater than 70%, with Sumba being the only exception. In all cases, pumped-hydro storage was favored to battery storage as renewable energy penetration exceeded 70%. A reduction in the investment cost of batteries of between 50 and 70% caused battery storage to become more favorable than pumped-hydro storage, and with lithium-ion battery costs forecast to fall by almost half in the coming 5 years [49], larger-scale battery storage will likely overtake PHS and may well become the best approach for island grid applications.

For renewable penetrations up to the optimal points in the range of 40–75%, opting not to make investment in renewables (primarily wind) for islands would be a missed opportunity considering the associated cost reductions. A practical way forward would be to add 10 or 20% renewable energy penetration each year in a staged process. This would allow islands time for battery costs to fall to a price competitive with pumped-hydro storage, and they could then be installed at a later date when renewable penetrations of 50–80% are achieved.

Competing interests

None.

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