Determination of Cost-Optimal Electricity System Configurations for the Transition to Sustainable Energy Systems on Islands

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Master of Science Thesis

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Energy and Industry

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This journey was quite a long and demanding one, and certainly not without its challenges for me. Balancing my time and maintaining a narrow focus on my project, while continuing in my role as Chairman of the TU Delft Green Office student board was not the most highly efficient set-up initially. Dividing my time between them resulted in the slightly extended period required to complete the project. However, achieving a harmonious balance and being able to switch on and off between my thesis topic and the broader perspective of our campus's sustainability, was rewarding, enjoyable and demanded meticulous time management abilities, which I am grateful to have developed.

Working on a topic of my choice was liberating, and I am pleased to say that my interest in it remains strong, as I understand and recognise the desire and need for all layers of society to accept a role in this transition to sustainable systems and ways of life. However, opting for a self-defined topic came with the implication that I was not part of a well-established, long-running group of a department of the University. I began - much like my islands - alone in the vast ocean (of academia), unsure of how to begin, where to look for answers, who to turn to for assistance, and how to address the large and complex task before me. The process of finding these answers, segmenting the project into manageable parts, planning, persevering, and establishing links and contacts with people able and willing to help, was an invaluable learning experience for me. It taught me a great deal about myself, how I work, and my capabilities as a student and future professional.

As I close this final chapter in my life as a student, it would be remiss of me not to acknowledge those who made this journey possible, and have been alongside me, every step of the way. To my mother and father, I am forever indebted to you for the tireless effort, encouragement, and support you have provided me, allowing me the freedom to pursue my aspirations - even as they led me abroad, away from you. The sacrifices you have made over the course of my life, to ensure I had the best possible chance of achieving my dreams, are exceptional, and I admire you both for your unwavering devotion, love, and dedication. To my brother and sister, being away from you is probably a little harder than I like to acknowledge at times, but the fact that we remain close is a testament to our bond, and I sincerely look forward to being with you both again, whenever it is I am back in Australia for good.

Lastly, to my close friends, colleagues, and house-mates both past and present, I thank you very much for supporting and at times enduring me, sharing the highs and lows with me, and challenging me when required. You made the journey ever more enjoyable, and have given me memories I will forever cherish.

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Abstract

The proliferation of sustainable energy technologies is growing at a steady rate, 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. Small islands present unique and interesting challenges in regards to the global energy transition since the majority are almost exclusively dependent on imported diesel and refined oil products, and the high comparative costs of electricity generation position them with a greater incentive to look to alternative energy sources. A number of islands have set ambitious renewable energy targets, however the execution of plans to meet them have left much to be desired. The barriers of availability of technical knowledge and expertise to political, social and economic factors, have hampered progress to date. There is a growing body of research into the potential for islands to utilise the renewable energy resources that many of the islands are abound with, although majority of this research has been limited in its technological comprehensiveness and global perspective towards islands.

In order to approach solutions to the aforementioned challenges, cost-optimal electricity system configurations were investigated and determined for 6 islands of different geographies, sizes and contexts, utilising photovoltaic (PV) energy, wind energy, geothermal, pumped hydro storage (PHS) and battery storage. A database was built in the process, of all the inhabited islands with populations of 10,000 to 1,000,000 people, which was additionally previously lacking. The results of the optimisations showed strong support for islands to invest in renewable energy technologies (particularly wind energy), with the levelised cost of systems (LCOS) for electricity generation decreasing considerably with increasing renewable energy penetrations, to an optimal point in the range of 40% to 80% RES 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 shares of renewable penetration. 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 PHS as a cost-favourable storage option, 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 penetrations increase - investing in storage options.

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Preface

On a sunny Friday afternoon - the 21st of August, 2015 to be exact - I sat down with my colleague (and good mate) Sjoerd Moorman in the Asia Room of the TU Delft Library, for an open, few-hour brainstorm on potential thesis topics that could capture our interest, passion and devotion. It became clear to us, in this expansive session, that we shared a mutual interest and deep concern for the sustainability of our planet in a broader sense, beyond the confines of a specialisation in a single technology, or even the energy field as a whole. The long road of thought brought us to a range of places, from the local environment of our University campus at TU Delft, to developing countries in Africa, and just about everywhere in between. But finally (with the consideration in our minds that it would probably make sense to do something energy-related since we had evidently, both intentionally elected to undertake the Sustainable Energy Technology (SET) Master Program) the journey delivered us to a common destination - the idea that we should start small, in areas with clear boundaries that could become shining examples to the rest of the world of what sustainable, self-sufficient, energy independent societies and systems could become... Islands it was!

With the idea to focus on sustainable energy for islands, we began to formulate a (somewhat vague) thesis topic proposal and completed a background search to identify professors who might be able to guide us on this mission. Among them, was the recently appointed to TU Delft, Prof.dr. Kornelis Blok, to whom we also forwarded our idea. And as it just so happened to be, Professor Blok had that same afternoon posted a Thesis Project Proposal (for SEPAM and SET students) on the topic of 'Ocean Energy for Isolated Communities'! We may never know whether he secretly adapted our brilliant idea and made it his own, or it was just pure coincidence, but in either case, we are very glad he was happy to meet with us and hear what we had to say. After expanding the project to allow several topics to be addressed, and subjecting us to the rigours of ensuring we were up to the task - putting us both on the spot by asking, with typical Dutch directness: "How good are you?"- We were able to convince him we were 'good enough', and are grateful he was willing to take us under his wing, to eventually form the 'Islands Thesis Group.'

“We will be known forever
by the tracks we leave.”

— *Native American Proverb*
Dakota Sioux

Chapter 1

Introduction

The proliferation of sustainable energy technologies is growing at a steady rate, 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 agreed upon at the COP21 in Paris last year, 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 favouring renewable energy technologies [1, 2].

The majority of small islands around the world are currently almost exclusively dependent on imported diesel and refined oil products to meet their energy needs. Diesel generation is the primary method used for electricity generation on these islands, for a couple of reasons. Firstly, because it is more suited to their smaller scale demand since it is more responsive to demand fluctuations; and secondly, diesel generation proves more cost-effective than the large-scale, centralised coal-fired or gas power plants in continental energy systems, which benefit from economies of scale, indigenous reserves and ease of transport [3]. Despite diesel generation being favourable to conventional coal or gas power plants, the smaller scale of electricity production and the volume and logistics of supply on islands, results in very high comparative electricity costs, which are often subsidised by their governments in order to buffer the prices and protect consumers from the full generation 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 case, or rather, a necessity for islands to shift towards sustainable energy systems.

The majority of 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 photovoltaic (PV), the door remains open for more novel technologies, such as wave, tidal and ocean thermal energy techniques, as well as 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 set ambitious targets for achieving sustainable energy integration (many aiming for 100%). Naturally however, there are numerous challenges associated with practically achieving this.

Firstly, in many cases, road-maps laying out short, mid- and long- term strategies to meet such targets are not sufficiently developed, or implementation has been inadequate [2].

Secondly, detailed data on energy demand patterns, system performance and renewable resource potentials is lacking or limited on many of the islands striving to transition to renewable energy systems [2]. To date, there is no existing database covering the scope of small islands with regards to their renewable energy resources and electricity system characteristics. A number of organisations cover a select group of islands including the International Renewable Energy Agency (IRENA), the Energy Transition Initiative (ETI), Eurelectric, the National Renewable Energy Laboratory (NREL), the Aegean Energy Agency (AEA), and the Network of Sustainable Aegean and Ionian Islands (DAFNI) - however none of these are by any means comprehensive in a global sense.

Thirdly, while these islands are developing their own road-maps for transitioning towards sustainable energy systems, many lack the required level of technical expertise to really make feasible and realisable plans. Additionally, there are specific stability issues to be considered, with the integration of increasing shares of variable renewables into diesel generator-based grids. Specific skill sets are needed for the proper operation and maintenance of systems that address these issues, which are also often found to be lacking [2].

Fourthly, in the early stages of adoption, new and unfamiliar power generation based on renewable resources are seen as difficult to design, operate and maintain when compared to the established oil-based systems in place today.

Fifthly, in addition to technical and human capacity issues, the social, political and economic environment on islands can present barriers to renewable energy uptake. Land tenure in the Pacific Island Countries and Territories (PICTs) for example is complex, with most land being communally owned and having complex systems of access rights. This factor, together with the common issue of the limited land area of islands and the existence of numerous cultural sites, can pose challenges to renewable energy systems that require significant land demands. Policy and regulatory frameworks on many islands have been set up for centralised utilities that are usually vertically integrated and state owned. These frameworks will likely require some adjustment to allow widespread renewable energy deployment.

1-1 Current Research

There is a growing body of research into the topic of optimal renewable energy configurations, which has predominantly focused on wind, solar photovoltaic, and hydropower as generation technologies, coupled with battery storage, pumped hydro storage and a few utilising hydrogen storage. However, almost all of these studies focus only on single, isolated case studies, rather than comparing multiple islands in a more comprehensive approach. Furthermore, it is apparent that many studies make approximations of both resource and demand data, rather than using real renewable resource data. The body of current research on the topics relevant to this thesis are fully explored in the **Literature Review**.

1-2 Project

This thesis project aims to address several of the aforementioned challenges, by providing a clear method for optimally utilising the renewable resource availability and storage possibilities, and determining how system cost-evolution takes place with increasing penetrations of renewables and storage, in order to facilitate such a transition in a multi-staged process. This will be achieved by creating a model that can serve as a guide to island governments and stakeholders wishing to transition towards renewable energy generation systems. It is initially envisaged that the model will be built in MATLAB/Simulink, with the optimisation aspect being performed utilising the internal optimisation functions of MATLAB, or (if infeasible) GAMS, a high-level mathematical and optimisation tool, suitable for this task. The outcome of the thesis will be a modelling tool that identifies cost-optimised, sustainable electricity system configurations, including generation and storage technologies. The inputs to the model will be the site-specific renewable energy resources, electricity demand, and properties of different generation and storage technologies at present. It is also intended that the thesis will give answers to the questions of how power system size (and geographical location) will influence the optimal technological configuration. In order to do so, the model will be applied to six (6) real island case studies consisting of varied populations, power system sizes, land areas and geographies, giving a characteristic indication of the geographical island groups, and island and power system sizes with most potential for successfully transitioning towards 100% sustainable electricity systems. As a means to achieving this goal, the project will also develop a database of islands in the predefined population range (10,000-1,000,000), with regard to their populations, land areas and current electricity system parameters.

1-3 Research Questions

1. What does a cost-optimal renewable electricity system configuration look like for islands within the specified population range, when both multiple production and storage technologies are considered?
   (a) Which generation and storage methods are favoured?
   (b) What insights can be gained from the comparison of various optimal configurations?
2. How do system costs and system configuration for electricity generation vary with increased penetration of renewable production technologies?
3. How does the scale of demand (and geographical location) influence the cost-optimal technological configuration for islands?

Chapter 2

Literature Review

A thorough literature survey was performed to garner an understanding of the scope of research that has been undertaken on the topic of optimal integrations of renewable energy sources to island electricity systems. An initial search was conducted with the Scopus document search tool, using the search terms "Renewable energy integration islands", "Optimal renewable energy system islands"and "Optimal renewable energy configurations islands."The results, shown in Figure 2-1 below, confirm the significant growing interest in the field of renewable energy integration and optimal system configurations for islands.

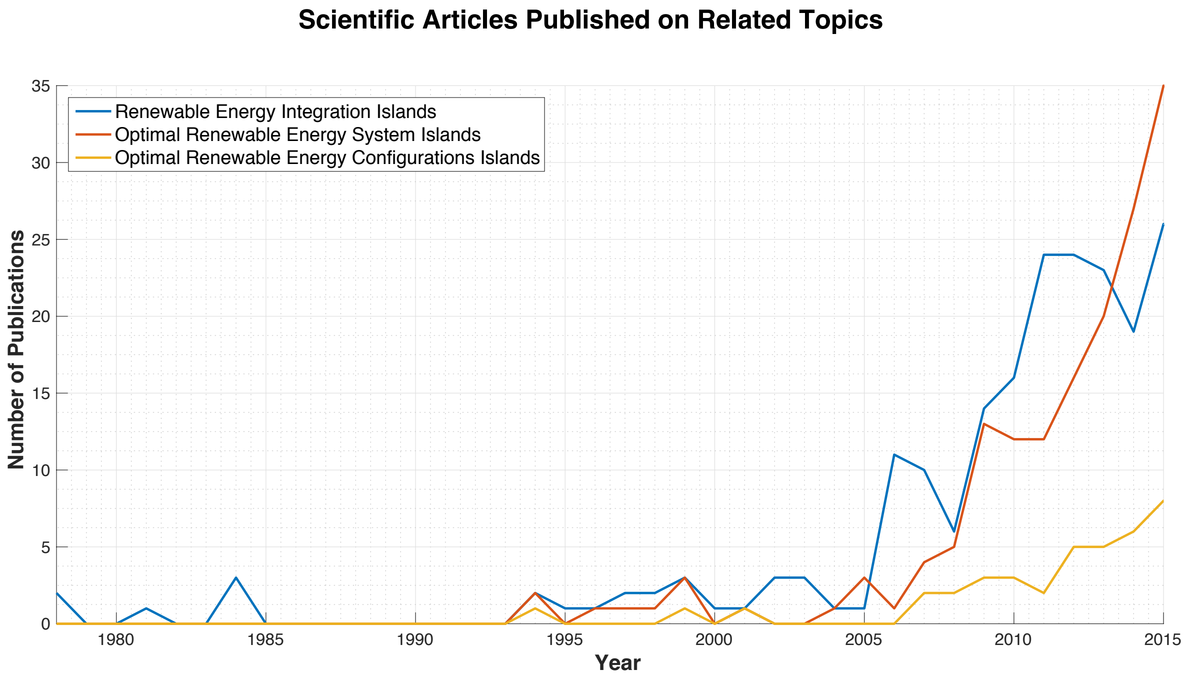


Figure 2-1: Scientific Articles Published on search terms

A total of 34 research papers were examined in the literature review. The review highlighted in particular:

- The combinations of production and storage technologies employed
- Software tools used for the modelling
- Type of modelling undertaken, and level of detail (time step, optimisation, reliability and/or sensitivity analysis)
- Control system logic implemented
- Models were almost exclusively applied to only single case studies
- Methods weren't proposed on how the transition to such an optimal system could realistically be achieved

It is important to note at this stage, that the influence of the objective of a research project naturally influences the analysis approach undertaken. This had to be taken into consideration in the literature review, as not every paper set out to achieve the same objective. For example, papers that opted for a more simple scenario-based analysis rather than solving a pure optimisation problem, are not necessarily rendered sufficient, when the objective was to ascertain a general indication of the domain of possible optimum configurations. However as previously stated, the objective of the literature review was precisely to generate an understanding of the variety of factors at play in the modelling of an optimal system configuration for islands transitioning to completely renewable-based electricity systems.

Out of the 34 research papers examined, 28 of them performed some kind of modelling for an electricity system with renewables integrated, with the others focussed on more qualitative research, such as challenges and barriers for renewable integration, optimisation or control methodology, or being literature reviews themselves. Unsurprisingly, the historically favoured conventional electricity generation technique for islands of Diesel Generators featured in 18 papers of the 28. It also came as no surprise that the mature renewable technologies of solar PV and wind energy were the most prevalent throughout the literature examined, with 24 papers including PV and 25 papers including wind respectively. Additionally, Fuel Cells were included in 7 studies, hydropower in 4, Biomass in 2, Wave energy in 2, Geothermal in 1, and Concentrated Solar Power also in 1.

On the storage side, the most commonly used technologies were Batteries, in 16 studies and hydrogen, in 7. Pumped hydro Storage (PHS) was utilised in 3 papers, two of which were part of the same research. An interesting observation was that out of all the papers examined, only 1 [5] investigated systems making use of multiple storage technologies, namely battery and H_2 storage, coupled with PV production. Thus, none of the papers included battery storage coupled with pumped hydro storage.

In terms of production and storage combinations, the most common renewable configurations were PV/wind/battery, investigated in 14 papers, and PV/wind/H_2 in 4 papers. Logically, all 7 of the papers that utilised Fuel Cells also employed H_2 storage. However, **none** of the papers reviewed included a PV/wind/PHS/battery combination. 3 studies investigated wind/hydro/pumped hydro storage, 1 investigated a PV/CSP/Biomass/FC/H_2 combination, while two looked at PV/battery (with one of these two also including H_2 storage).

Tool	Geographical area	Scenario timeframe	Time-step
			1. National energy-system tools
			1.1. Time-step simulation tools
Mesap PlaNet	National/state/regional	No limit	Any
TRNSYS16	Local/community	Multiple years	Seconds
HOMER	Local/community	1 year[a]	Minutes
SimREN	National/state/regional	No limit	Minutes
EnergyPLAN	National/state/regional	1 year[a]	Hourly
SIVAEL	National/state/regional	1 year[a]	Hourly
STREAM	National/state/regional	1 year[a]	Hourly
WILMAR Planning Tool	International	1 year[a]	Hourly
RAMSES	International	30 years	Hourly
BALMOREL	International	Max 50 years	Hourly
GTMax	National/state/regional	No limit	Hourly
H2RES	Island	No limit	Hourly
MARKAL/TIMES	National/state/regional	Max 50 years	Hourly, daily, monthly using user-defined time slices
			1.2. Sample periods within a year
PERSEUS	International	Max 50 years	Based on typical days with 36–72 slots for 1 year
UniSyD3.0	National/state/regional	Max 50 years	Bi-weekly
RETScreen	User-defined	Max 50 years	monthly
			1.3. Scenario tools
E4cast	National/state/regional	Max 50 years	Yearly
EMINENT	National/state/regional	1 year[a]	None/yearly
IKARUS	National/state/regional	Max 50 years	Yearly
PRIMES	National/state/regional	Max 50 years	Years
INFORSE	National/state/regional	50+ years	Yearly
ENPEP-BALANCE	National/state/regional	75 years	Yearly
LEAP	National/state/regional	No limit	Yearly
MESSAGE	Global	50+ years	5 years
MiniCAM	Global and regional	50+ years	15 years
			2. Tools with a specific focus
			2.1. Time-step simulation tools
AEOLIUS	National/state/regional	1 year[a]	Minutes
HYDROGEMS	Single-project investigation	1 year[a]	Minutes
energyPRO	Single-project investigation	Max 40 years	Minutes
BCHP Screening Tool	Single-project investigation	1 year[a]	Hourly
ORCED	National/state/regional	1 year[a]	Hourly
EMCAS	National/state/regional	No limit	Hourly
ProdRisk	National/state/regional	Multiple years	Hourly
COMPOSE	Single-project investigation	No limit	Hourly
			2.2. Sample periods within a year
EMPS	International	25 years	Weekly (with a load duration curve representing fluctuations within the week)
WASP	National/state/regional	Max 50 years	12 load duration curves for a year
			2.3. Scenario tools
In*vert*	National/state/regional	Max 50 years	Yearly
NEMS	National/state/regional	Max 50 years	Yearly

[a] Tools can only simulate 1 year at a time, but these can be combined to create a scenario of multiple years.

Figure 2-2: Modelling tools reviewed by Connolly et al. in [6]

The investigation into the software and modelling tools available and used in determining an optimal system sizing with integrated renewable energy resources yielded the following results. Firstly, it was discovered that there are a vast range of tools available that can assist in such an analysis. Connolly et al., [6] performed an extensive review of 37 software tools that can be used to analyse the integration of renewable energy into existing energy systems. The tools vary in their suitability depending on scale, technologies used, time scale, and availability. They concluded that the selection of a tool is dependant upon the specific objectives of research, and there is no single tool that is ideal for all situations. They also found that “90% of the energy tools considered had never simulated a 100% renewable based energy system.” Figure 2-2 above shows the list of tools that were reviewed in [6], and the geographical area they are best suited to, along with the time frame they can create scenarios for and the time-step used in the models.

The tools which are designed for modelling smaller geographical areas in the ‘Local/Community/Island’ scale appear to be most suitable for the analysis of islands with populations in the range considered in this research. As can be identified in Figure 2-2 above, these tools are TRNSYS16, HOMER and H2RES. This hypothesis is substantiated through the papers examined, in which out of the 17 papers that embarked on modelling and stated which tool they used, 9 utilised TRNSYS16, HOMER or H2RES. Furthermore, 5 papers made use of MATLAB and/or Simulink. Of the remaining studies, 2 used EnergyPLAN and 1 NEPLAN - suggesting that it is possible to utilise tools designed for larger scales - however, a large proportion of the papers (11) did not state which tool(s) they used to perform their analysis.

A number of papers reviewed also opted for determining an ‘optimal system’ by identifying the best performing system from a specified range of proposed options, rather than determining a purely optimal system by solving an optimisation problem. This was the case in [7, 8, 9, 10, 11] which specified a number of system configurations and then found the best performing system among those proposed.

On time scale and simulation period, the hourly time step was most favoured in the papers reviewed, with 19 out of the 28 adopting it in their studies. Only 3 papers made use of a second or minute time step. Most papers also simulated for a period of a year, however some only investigated much shorter periods, in the order of days or months.

Through the literature review, a few different categories of studies emerged:

1. Optimisation with HOMER for small systems
2. Optimisation with other tools, on Net Present Value (NPV) or Levelised Cost of Energy (LCOE)
3. Complex, multi-criteria optimisations for hybrid energy systems
4. Control system logic and system performance

Optimisation with HOMER for small systems

Firstly, the studies that utilised HOMER software all followed the same process, of identifying the production and storage technologies to be investigated, determining the optimised system configuration based on the single criteria of net present cost (NPC), and then usually performing a sensitivity analysis to determine the influence of one or more factors on the system configuration. The system sizes that HOMER was used for were all relatively small systems, ranging from 40kW to 240kW, with two studies looking at relatively larger systems of 3 and 4 MW.

Optimisation with other tools, based on NPV or LCOE

This group of studies focused on determining an optimal system based on NPV or LCOE, using one of the previously listed tools (although many didn’t state which one specifically).

The systems examined in this category were also predominantly small-scale systems, in the range of 0.3kW to 85kW, with four studies looking at larger systems in the order of 3 to 50 MW. The island with the largest population examined was Miyako, with a population of 56,000 inhabitants. This group of studies were generally carried out in the following manner: A specific case study for the focus of that research was introduced, and that island's energy demands were stated, with some of them looking into future demand growth. Then, some of the renewable energy sources were either acquired from real data, or synthesised from similar data. Usually, a few production and storage technologies were selected from this, and it was then detailed how these technologies would be modelled mathematically. Some configuration options or integration scenarios were then created and an explanation of the optimisation criteria was presented. The 'optimal' configuration was then determined from an economic perspective, with the more detailed studies undertaking more physical reliability analysis, and including this in their optimal system criteria.

Bueno & Carta [12] built a model for sizing components, and economic optimisation with technical restrictions of wind-powered pumped hydro storage systems. However, their model was only suitable for areas with topographically suitable sites with sufficient wind resources. Bueno & Carta [13] then also applied their model to the Island of El Hierro, with their results showing that annual renewable energy penetration of 68% could be achieved, and the renewable system was cost competitive with the conventional system when fuel prices were 0.283€/L.

Chua et al. [10] evaluated the potential for integrating renewables into tri-generation systems for islands, to meet heating, cooling and electricity demands. They modelled a tri-generation system, and found that renewable penetration of 20% offered comparable economic savings of USD $130,000 per year and a CO_2 equivalent reduction of approximately 1000 tonnes per year, 21% reduction of primary energy consumption. 40% penetration resulted in 23% reduction in primary energy consumption, but incurred economic losses. This research could not provide a cost effective solution to support a renewable energy penetration of greater than 40%. Furthermore, the study failed to take into consideration the availability of the biomass resources on the island of Pulau Ubin.

Senjyu et al. [14] built a model for optimal sizing of components to meet demand for 3 Japanese Islands, using PV, wind, diesel generation and batteries. Cost optimisation was done using a generic algorithm (GA). Their results showed that PV wasn't used at all because of its high comparative expense, even when subsidised.

Duić and da Graça Carvalho [15] presented a model for optimisation and energy planning, using wind and a wind/PV mix, with H_2 storage and a fuel cell. Their model was applied to Porto Santo. For peak shaving, the wind/PV mix was more effective, but for 100% penetration of renewables, purely wind was more cost effective. They also asserted "the most promising technologies are reversible hydro where geography allows, and storing hydrogen where it does not" [15].

Cruz Barco [16] utilised the Energy Hub framework in MATLAB/Simulink to develop an optimal configuration of a small-scale renewable energy system to attempt to independently power the 'Croon Facility' Building in The Hague, in a wind/PV/CHP grid-connected system.

Katsaprakakis et al. [17] analysed a system configuration for wind, PV, diesel generator and batteries to meet the seasonal electricity demand of Dia Island, with excess energy used for desalinating water in the uninhabited months. Hourly power demand was synthesised using a Weibull distribution, and the system was optimised using the life cycle costs.

Demiroren and Yilmaz [18] built a model to identify an economic optimal configuration for a PV/wind/Diesel/Batteries system on Gökceada, the largest island of Turkey. They concluded that wind was most advantageous and PV was too expensive, and using wind energy was most attractive in the case it was grid connected. They did not examine the use of any other renewable technologies or storage methods.

Yue, Chen and Lee [19] examined the yearly energy potential able to be produced from renewable energy sources of wind, solar, biomass and wave energy for Wang-An Island, which largely outweighed the current energy demand of the island. The situation was the same for electricity, with potential production dwarfing the the demand. This paper did not examine methods of storage, and therefore did not optimise for meeting energy demand at all times. As a result, electricity production from fully exploited renewables was able to meet 5.8GWh out of the 6.4GWh total demand, due to mismatches between supply and demand. There was also an enormous amount of energy that was produced in excess, and this would only be advantageous if it could be exported via underwater cables to neighbouring grids.

Cosentino et al. [7] created a number of scenarios for transitioning to a renewable based smart energy grid for a real islanded network located in the Island of Pantelleria, in the Mediterranean Sea, and then performed an economic cost-benefit analysis and detailed electrical analysis for a scenario that covers around 50% of the demand with renewable sources. Their results showed that it is beneficial for the Island of Pantelleria to transition towards renewable systems.

Complex, multi-criteria optimisations for hybrid energy systems

This group of studies concentrated on solving the complex optimisation problems posed by hybrid renewable energy systems, as a result of multi-criteria optimisation objectives, often with non-linear, non-convex natures. The factors contributing to this are the intermittent nature of renewables, coupled with system reliability, need for demand to be met at all times, expense of back up generation and storage, as well as environmental criteria and the need for the system to effectively fulfil all these criteria while also minimising costs.

Baños et al. [20] provide an overview of the latest research developments concerning the use of optimisation algorithms for design, planning and control problems in the field of renewable and sustainable energy. The technologies covered include: wind, Solar, hydropower, Bioenergy and geothermal energy. Then, an overview of various algorithms and optimisation approaches are presented for hybrid renewable energy systems, such as Genetic Algorithms (GA), Multi-Objective GA, Evolutionary Algorithm (EA), Multi-Objective EA (MOEA), Particle Swarm Optimisation (PSO), Linear Programming (LP), fuzzy logic, Pareto-based optimisation, and one paper which used a hybrid Pareto-based multi-objective meta-heuristic that combined Pareto archived evolution strategy (PAES) with Simulated Annealing (SA) and Tabu Search (TS).

Bajpai and Dash [21], review the research on the unit sizing, optimisation, energy management and modelling of hybrid renewable energy system components, focussing on Solar PV, with H2, FC and battery. They identify a number of parameters used in literature for technical performance optimisation, such as Loss of Load probability (LOLP), Loss of Power probability (LOPP), Loss of Power Supply probability (LPSP) and Load Coverage Rate (LCR). They also make the distinction between approaches of unit sizing, between conventional techniques (where weather data is accessible) and Artificial Intelligence (AI) techniques such as such as Artificial Neural Networks (ANN), Fuzzy Logic (FL), Genetic Algorithms (GA) or a hybrid of these techniques, for smaller, isolated locations.

Notton et al. [22] also identified target functions which could be used to perform such an optimisation. They included cost of energy (COE), System sustainability (minimum number of supply interruptions) and fuel consumption (minimal use of conventional generation).

Bernal-Agustín et al. [23] reviewed the various simulation, optimisation and control strategies for hybrid standalone renewable systems, particularly: wind, PV, diesel, battery and H2 systems. They also determined NPC or LCE as the most commonly used economic optimisation criteria, as well as referencing that reliability restrictions are usually included evaluating effectively the same thing, using either LOLP, LOSP, or Unmet Load (UL), the fraction of time the load is unmet from the total load time, usually a year. Some studies had also implemented Multi-Objective Evolutionary Algorithms (MOEAs), to perform multi-criteria optimisations.

Deshmukh and Deshmukh [24] reviewed methods to model Hybrid Renewable Energy Systems (HRES) and their components, different topologies and their characteristics, and also identified LOLP and Life Cycle Cost (LCC) as the criteria used for optimisation. Cruz Barco (2013) optimised with the objective of minimising power exchange with the grid. For this, he defined the term energy 'autarky' and examined what the most optimal system configuration is to achieve this. He examined in detail the optimisation theory regarding the objectives of minimising power exchange and improving battery utilisation. He recommended using multi period optimisation, by looking ahead and forecasting the energy demand in the future. A means of which he suggested for his project, could be looking into the following day's calendar to see if it is a working day or not.

Control system logic and system performance

This category of studies was concentrated on the control system logic and performance, which was also integrated in many of the papers previously mentioned. Important decisions need to be made in the control logic and management of a hybrid renewable energy system in order to remain balanced at all times. These include the proportion of renewable energy penetration permitted, which generation technologies are prioritised, the level to which storage can be discharged, how excess energy is dealt with, and how system reliability is maintained in the case of faults. Bernal-Agustín and Dufo-López [23] identified a number of control strategies that can be employed. Barley et al. [25] first proposed the following strategies:

- Zero-charge strategy: the batteries are never charged using the diesel generator, the set point of the State of Charge is 0

- Full cycle-charge strategy: the batteries are charged to 100% of their capacity every time the diesel generator is on; set point of State of Charge is 100%.

- Predictive control strategy: the charging of the batteries depends on the prediction of the demand and the energy expected to be generated by means of renewable sources, so there will be a certain degree of uncertainty. With this strategy, the energy loss from the renewable energies tends to decrease.

Barley and Winn [26] improved the control strategies just listed and proposed 4 control strategies, introducing the parameter Critical Discharge Power. This is the value at which the net energy (that demanded by the loads minus that supplied by the renewable sources) is more profitable when supplied by means of the diesel generator than when supplied by means of the batteries (having previously been charged by the diesel generator). This parameter became of great importance in the control strategies of the software tools HYBRID2, HOMER, and HOGA.

- Frugal Dispatch strategy: if the net demand is higher than Critical Discharge Power, the diesel generator is used. If it is lower, the batteries are used.
- Load Following strategy: the diesel generator never charges the batteries.
- SOC Set-point strategy: the diesel generator is on at full power, attempting to charge the batteries until the SOC Set-point is reached.
- Operation strategy of diesel at maximum power for a minimum time (charging the batteries).

Bajpai and Dash [21] discuss power management strategy considerations, such as maximising renewable use, capital and operational costs, state of charge of storage devices and time at which they can feed the load autonomously, start-up and shut-down cycles, and fuel prices. Many other papers also suggest and implement their own control system strategies, usually fitting in to one of the previously mentioned categories.

Bueno & Carta [13] tested four control strategies for a wind/hydro/pumped hydro system in El Hierro: 1) having two independent electrical systems. 2) Electric resources are disconnected when storage is full. 3) All generating systems are connected to the same electrical grid. 4) Non-controlled load demand is covered by different electricity generation subsystems, depending on whether or not the upper reservoir has reached its maximum capacity.

Qi, Liu and Christofides [27] proposed a conceptual control framework for controlling a renewable electricity system. They applied this to a specific example: simulating a wind/PV/Desalination system connected to the grid. In this smart grid, the flows of energy were controlled from wind, solar and batteries to the demand of a system. A supervisory predictive control was used and system maintenance and optimal system operation were taken into account, which had not been considered in previous works. They concluded that predictive control could be used as a suitable and effective control methodology for such applications.

Li et al. [5] employed a simple preferential strategy, whereby if the renewable production (PV) was unable to meet the demand, storage was used - with batteries prioritised over hydrogen/fuel cell use - and in the case the storage could not satisfy the demand, the system was shut down.

Erdinc et al. [28] discussed many of the challenges in relation to physical power flows and grid reliability in detail, particularly rotor angle, frequency and voltage, as a result of high penetration of renewable energy, and suggested some methods for addressing these.

In terms of case study applications, the overwhelming majority of modelling studies were carried out for single island case studies. Only **2 of the 28 studies investigated multiple**

islands in their case studies, and in both cases the multiple islands were part of the same island group. On the topic of methodology for transition, essentially all of the studies were silent on really proposing a strategy of how a realistic and structured approach could be adopted to transition to the system they had determined optimal. Also, the influence on system composition based on system size and geographical location was not investigated at all. Furthermore, the literature review highlighted the opening to investigate a hybrid renewable based electricity system for islands including multiple production ***and*** multiple storage technologies, since a system including both was not identified in any of the papers that were reviewed.

Chapter 3

The Island Context

3-1 Islands Identification

As previously mentioned in the Introduction, islands are faced with unique challenges in relation to electricity generation, and as a result have greater incentives to reduce their dependence on fossil fuels and transition to renewable energy sources. Their limited size and isolation, limited indigenous conventional reserves, and the elevated costs associated with the logistics of transporting and delivering liquid fuels - not to mention the environmental and political factors - all add up to high electricity generation costs, and contribute to a pressing need for change.

The starting point for this research is to determine how many significantly populated islands actually exist in the world, since there is no single database known to hold all of this information. From this, it could be ascertained what proportion of people in the world live on such islands, and what the potential impact could be in seeing them transition to renewable electricity systems. A couple of incomplete databases do exist, specifically the UNEP Island Directory [29], WorldIslandInfo.com's 'Principal World Island and Groups' list [30] and a list of islands found via worldatlas [31].

An extensive search was carried out to identify all of the islands within the population range of 10,000 to 1,000,000 inhabitants. The reason for the selection of these bounds, is that islands with populations of less than 10,000 have been investigated quite extensively already, and are a little more simple to approach in terms of a transition to renewable energy, as this can be done in a more distributed manner. Larger islands, with populations greater than around 1,000,000 people, tend to possess native resources conducive to conventional electricity generation, and their grids start to resemble those of regular continental grids.

In total, **297** islands were identified within the 10,000 - 1,000,000 population range, with a combined population of 39.5 million people, approximately 0.53% of the total world's population. Data was gathered not only on population, but on geographical location, land area, population density, and highest elevation (to give a crude indication of the topography i.e. flat or mountainous).

3-2 Islands Characterisation

In order to start to categorise the islands and determine some interesting focus areas, some basic analysis was performed on the data. Firstly, a spatial distribution of the islands was made, and is shown below in Figure 3-1.

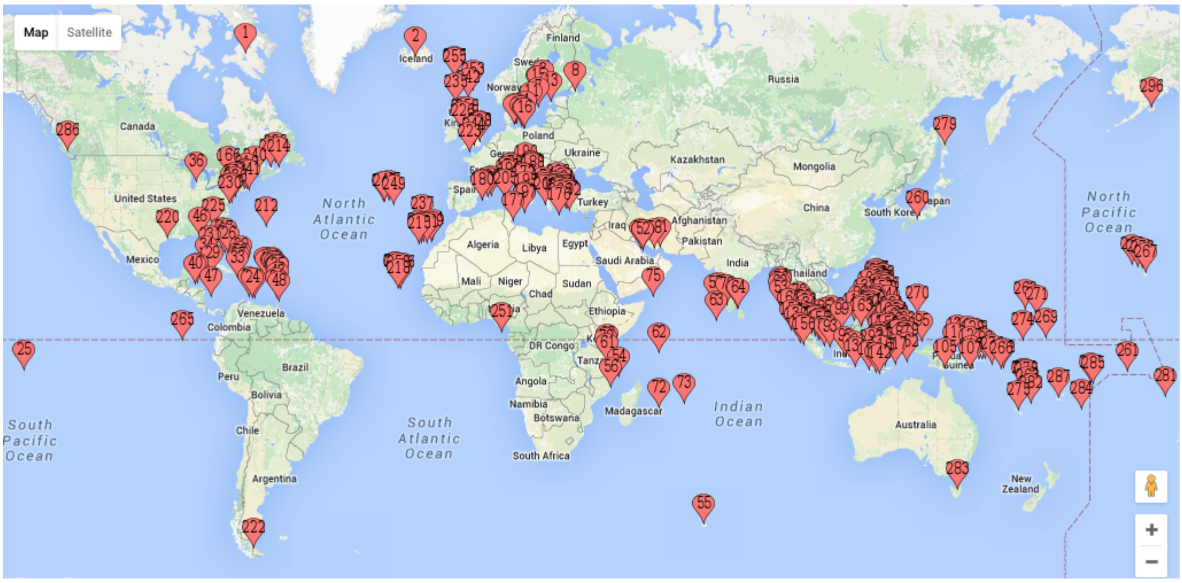


Figure 3-1: All Islands identified in Population Range

Water Body	Number of Islands
Arctic Ocean	2
Baltic Sea	14
Caribbean Sea	35
Indian Ocean and Persian Gulf	31
Malay Archipelago	96
Mediterranean Sea	40
North Atlantic Ocean	49
Pacific Ocean	30

Table 3-1: Distribution of Islands by Water Body

In order to see where the total population of island inhabitants was distributed spatially, the populations per water body were also determined, shown in Figure 3-2.

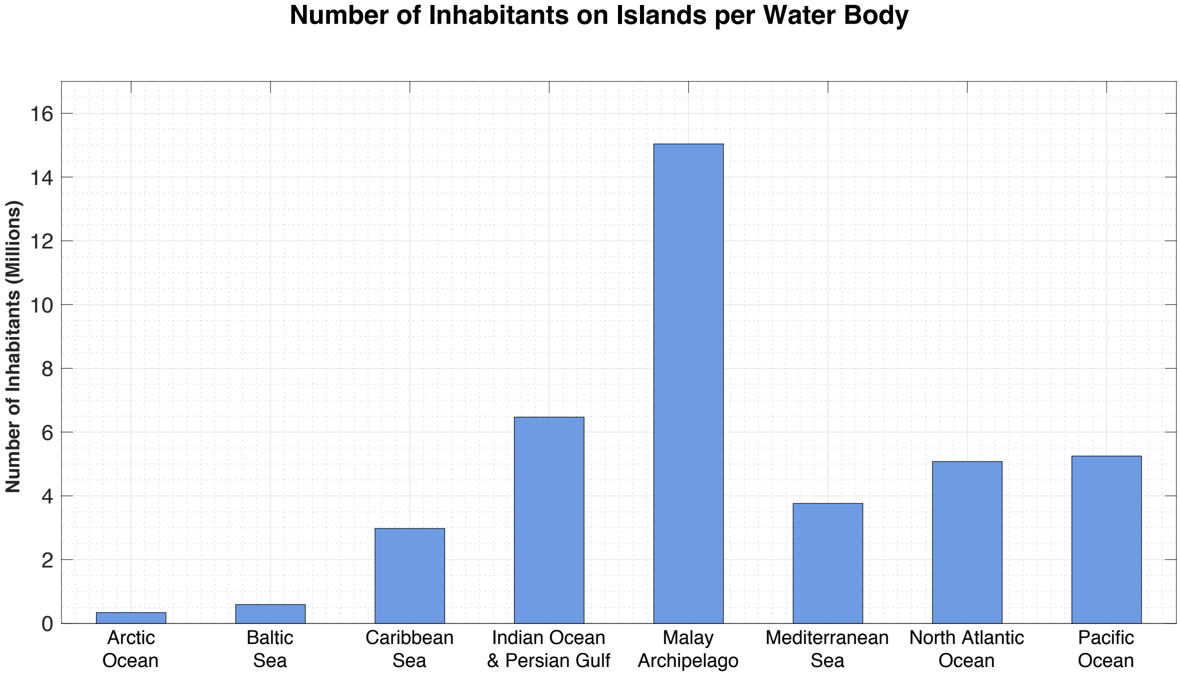


Figure 3-2: Number of island inhabitants per water body

Beyond this, it was also deemed of interest to determine the relationship between the number of islands per population range, and the total population per population range. These can be seen below in Figure 3-3 and Figure 3-4. It is interesting here to note that although there are many more islands in the smaller population ranges, the weight of the fewer, more highly populated islands is noticeably larger.

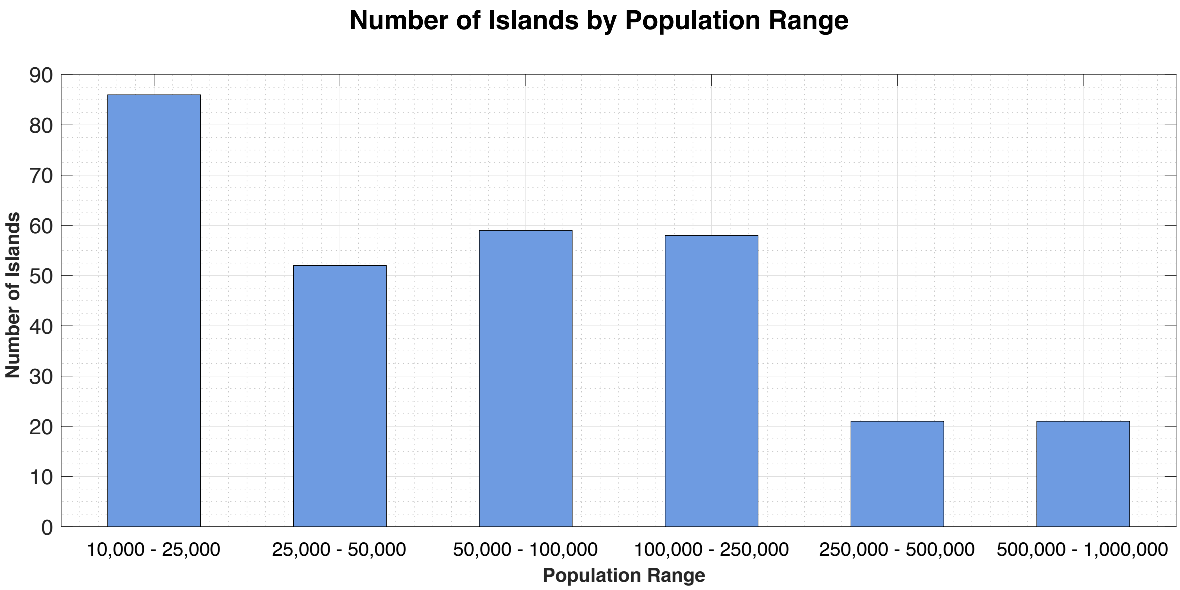


Figure 3-3: Number of islands by population range

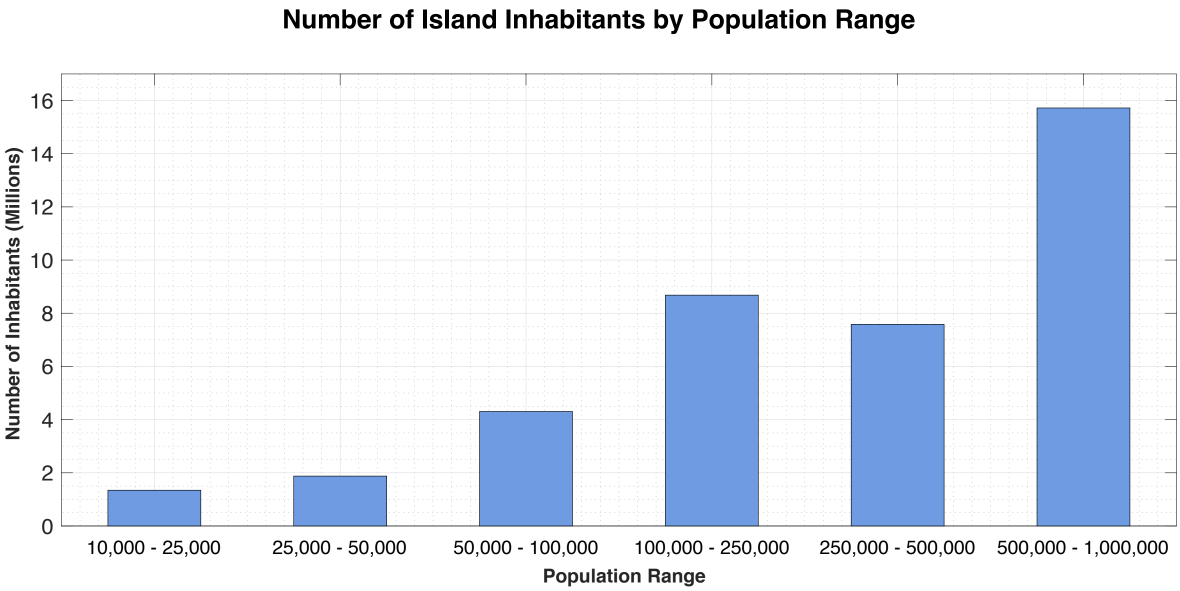


Figure 3-4: Number of island inhabitants by population range

With this general information from the identification and categorisation now at hand, it is possible to proceed to the process of selecting a specific number of island case studies for detailed analysis in this project.

Chapter 4

Island Case Studies

4-1 Selection Criteria

A number of criteria were defined in order to condense the total list of islands to a representative and manageable number to be analysed. These criteria were:

1. Each of the major island groups (per water body) represented: It is intended that most - if not all - of the major island groups that were identified above, will be represented.
2. Political interests: It was preferable to select islands that had already agreed upon renewable energy targets, as the outcomes of this research would be more relevant for these islands. Also they would be more likely to proceed with further detailed studies and implementation based on these outcomes.
3. Non grid-connected: A connection to a continental grid largely resolves many of the challenges islands face in terms of electricity generation, so the decision was made to focus explicitly on those that are non-connected, and also don't have plans in the future for constructing such a connection.
4. Islands in the range of 100,000-1,000,000 inhabitants represented: As mentioned previously, the islands in this range represent the largest portion in terms of population, and have received less attention to date in terms of renewable energy research than smaller islands, so it is preferable to have 1-2 represented in this research.
5. Area: A range of island sizes in terms of land area should be included, to have a basic understanding of how feasible the optimal configurations would be in terms of land availability on various island sizes.
6. Development status: It is a preference to include at least one island that is currently in a developing state.
7. Data availability: It is understood that acquisition of the required demand and renewable resource data can be a challenge, and therefore data availability is also considered in the selection process.

4-2 Relevant Islands identified

Island	Ocean/Sea	Renewable Energy/Electricity Target
Gotland	Baltic Sea	100% renewable energy balance by 2025
Aruba	Caribbean	100% renewable energy by 2020
Bahamas	Caribbean	Increase dependency on renewables to 30% by 2030
Barbados	Caribbean	29% of electricity generation by renewables by 2029
Bonaire	Caribbean	100% renewable energy by 2015
Dominica	Caribbean	Increase renewable energy generation from current 30% from hydro to 100% by adding geothermal energy to the mix; and: Become carbon negative by exporting renewable energy to its neighbours Guadeloupe and Martinique by 2020
Guadeloupe	Caribbean	50% of electricity from renewable sources by 2020
Martinique	Caribbean	50% of electricity from renewable sources by 2020
Saint Lucia	Caribbean	20% renewable energy by 2020
Saint Vincent	Caribbean	Deliver 30% of projected total electricity from Renewable Energy Sources (RES) by 2015 and 60% by 2020
US Virgin Islands	Caribbean	30% renewable energy by 2025
Maldives	Indian Ocean	Carbon neutrality in the energy sector by year 2020
Mauritius	Indian Ocean	35% renewable energy by 2025
Réunion	Indian Ocean	Become a net zero energy island by 2025
Seychelles	Indian Ocean	Renewable energy target of 15% by 2030
Sumba	Malay Archipelago	100% renewable electricity generation by 2025, and 95% access (to renewable electricity) by 2020
Greek Islands	Mediterranean Sea	18% renewable energy share in gross final energy consumption, 40% of electricity demand met with renewable sources
Canary Islands	North Atlantic	36% of its energy met with renewables by 2020
Cape Verde	North Atlantic	Promote the development of renewable energy projects to achieve 25% renewable energy penetration in 2012 and 50% in 2020 and on one island (Brava) attain 100% penetration of renewables
Faroe Islands	North Atlantic	100% green energy production by 2030
Hawaiian Islands	North Pacific	100% renewables by 2045
Kodiak Island	North Pacific	50% of electricity from renewable sources by 2025
Cook Islands	Pacific	100% renewable energy by 2020
Fiji	Pacific	80% renewable electricity generation by 2020, 100% by 2030
Kiribati	Pacific	Renewable electricity generation of 23% on South Tarawa, 40% on Kiritimati 40% of rural public infrastructure and 100% for rural public and private institutions by 2025.
Marshall Islands	Pacific	20% of energy through indigenous renewable resources by 2020
Nauru	Pacific	At least 50% of energy demand provided by alternative sources of energy including through renewable sources by 2015
Palau	Pacific	20% of electricity from renewable sources by 2020
PNG	Pacific	100% renewable energy by 2030
Samoa	Pacific	20% by the year 2030/100% electricity by 2017
Solomon Islands	Pacific	100% renewable energy by 2030
Tonga	Pacific	50% renewable energy by 2020
Vanuatu	Pacific	100% renewable energy by 2030

Table 4-1: Selected Islands with Specific Renewable Energy/Electricity Targets

Considering these criteria, an initial scan was performed to identify a pool of relevant, potential case study locations, that can be seen in Table 4-1. Note that this was not a complete search of all of the 297 islands identified, and hence there is surely more islands than are listed, that have set targets for renewable energy/electricity.

10 island challenge – Carbon War Room

The Carbon War Room is a global non-profit founded by Sir Richard Branson, comprised of entrepreneurs. "It aims to accelerate the adoption of business solutions that reduce carbon emissions at a macro-scale and advance the low-carbon economy." The organisation focuses on solutions that can be realised using proven technologies under current policy landscapes [32].

At Rio+20, Christiana Figueres, Executive Secretary of the United Nations Framework Convention on Climate Change, challenged the Carbon War Room to work with ten Caribbean islands to accelerate their transition off fossil fuels. That challenge was accepted, and resulted in the formation of the 'Ten Island Challenge.' Naturally, these ten islands are of relevance:

1. **Aruba**
2. **Belize**
3. **Bahamas**
4. **British Virgin Islands**
5. **San Andrés**
6. **Providencia**
7. **Dominica**
8. **Grenada**
9. **Saint Kitts and Nevis**
10. **Saint Lucia**
11. **Turks and Caicos**

Also taken into consideration as a reference was the work of IRENA in their Islands Initiative and Pacific Lighthouses. The Islands Initiative aims to "accelerate global adoption of renewable energy on islands by working jointly on establishing an enabling environment for renewable energy deployment in Island States, and States with inhabited islands"[33]. The Pacific Lighthouses initiative aims to "provide island governments and stakeholders, with baseline information to assist in the development of local renewable energy deployment roadmaps, as well as strengthening the implementation of regional initiatives" [34]. In light of the overlapping aim of this research, IRENA was consulted with in order to see if there were opportunities to investigate islands of mutual interest.

A couple of other islands without specific renewable energy targets were included in the long list as possibilities, just as matter of pure personal fascination:

Baffin Island (Arctic Ocean)
Sao Tome and Principe (North Atlantic)

4-3 Case Studies Selection

With the specific identification of the islands above and the selection criteria in mind, an initial selection was made of 3-5 islands per water body, which was then finally cut to six, as shown below.

Arctic/North Atlantic (1)	**Caribbean Sea (1)**
Eysturoy or Streymoy (Faroe Islands)	Aruba
Baffin Island	Dominica
Shetland	Bonaire
Malay Archipelago (1)	**Mediterranean Sea (1)**
Sumba	Rhodes
Koror, Palau	Syros
Papua New Guinea	Hvar
Savu	Korcula
North Atlantic (1)	**Pacific (1)**
Gran Canaria	Cook Islands
Madeira	Hawaiian Islands
Santiago	Nauru
São Miguel	Malaita or Guadalcanal

Table 4-2: Initial Short-list Selection

4-3-1 Final Selection

Figure 4-1: Islands Selection

1. **Streymoy (Faroe Islands)**
2. **Aruba**
3. **Sumba**
4. **Rhodes**
5. **Gran Canaria (Canary Islands)**
6. **Rarotonga (Cook Islands)**

4-4 General Information on selected Islands

4-4-1 Streymoy

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 north-west corner. Streymoy has a sub-polar oceanic climate, with average monthly temperatures of 3.4°C in the winter and 10.6°C in the summer, and is home to the capital city, Tórshavn, which is among the cloudiest places in the world with very low significant sunshine hours per day. It has a population of 22,400 inhabitants, representing around 40% of the total Faroe Islands population. The island has a parallelogram shape, with a land area of 373km^2 running in north-west south-east direction with a length of 47km and width of about 10km. The main energy supplier on the island, SEV, has set a goal to have 100% green energy production by 2030. The Faroe Islands' power generation mix in 2015 consisted of around 18% wind, 42% hydro-power 40% oil. The consumer price of electricity in 2010 was around $US 0.26/kWh.

4-4-2 Aruba

Aruba is an island located in the southern part of the Caribbean Sea, around 30km 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 it is more dry and arid. The average monthly temperature varies within a narrow range between 26.7°C and 29.2°C, a reason for it's popularity as a tourist destination. It has a resident population of 103,400 inhabitants, and an additional tourist population ranging at any one time between 60,000 and 90,000 people. The island has a parallelogram shape, with a land area of 179km^2 running in north west-south east direction with a length of 32km and width of 10km at its widest point. Aruba has set an ambitious goal of 100% renewable energy by 2020. Aruba's power generation mix currently consists of around 18% wind energy, with the 82% remainder being met by Heavy Fuel Oil (HFO). The electricity price has four rate structures, with residential consumers paying a base price starting at $US 0.25/kWh.

4-4-3 Sumba

Sumba is an island located in the eastern section of the Indonesian Archipelago, west of West Timor and around 700km 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 [35]. The average monthly temperature varies between 22.3°C and 30.7°C. The island has a population of 685,186 inhabitants, and an allantoid-shape, with an area of 11,153km^2 running in the east-west direction. Sumba is a developing region, and one of the poorer islands in Indonesia, with electricity access only around 25%. The island was selected for the 'iconic island' project, initiated by HIVOS, as a showcase for the possibilities of Indonesian islands to transition to

100% renewable energy islands. As part of the project, the government adopted the target of 100% renewable electricity generation by 2025, and 95% access (exclusively to renewable electricity) by 2020. Both of the main grids in the Sumba electricity network are served exclusively by diesel generators of varied capacities between 20 and 50kW. Additionally, there is one 800kW hydro plant, which constitutes around 8% of the total installed capacity. The selling price of electricity to the public is equivalent to $US 0.07/kWh, but as a result of this price, the electricity producer (PLN) incurs a loss of up to $US 0.25/kWh it generates.

4-4-4 Rhodes

Rhodes is the largest of the Greek Dodecanese islands, in the Mediterranean Sea, around 18km 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. The island has a population of 115,490 people, and a spearhead shape running north east-south west, with an area of 1,401km^2, 77km long and 37km wide at its widest point. Rhodes has not set an individual renewable energy target, but Greece as part of the EU 20-20-20 by 2020 policy has the target of achieving an 18% renewable energy share in gross final energy consumption, and 40% of electricity demand met with renewable sources. The power generation mix in Rhodes consists of 12MW of wind [36], 94MW of diesel generators, 30MW of steam turbines and 68MW of gas turbines [37]. The average electricity tariff for medium-sized households in Greece in 2015 was $US 0.20/kWh, though in Rhodes the price is likely higher.

4-4-5 Gran Canaria

Gran Canaria is the third largest of the Spanish Canary Islands, situated in the Atlantic Ocean around 150km west of the coast of Morocco. It is renowned for its variety of micro-climates, 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 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. Its population is 847,830 constituting around 40% of the total population of the archipelago. The island has a round shape with an area of 1560km^2 and is of volcanic origin with increasing elevation towards its centre. The Canary Islands government has set the target of meeting 36% of its energy with renewables by 2020. The power generation mix in the Canary Islands in 2015 was around 8% from renewable sources (5% from onshore wind and 3% from PV), with the remaining 92% met by combined cycle plants, steam turbines and diesel generation. The cost of electricity on the Canary Islands varies depending on the power demanded, for small to medium sized households the price ranges from $US 0.13-0.18/kWh.

4-4-6 Rarotonga

Rarotonga is the largest and most populous island of the Cook Islands, lying in the South Pacific Ocean around 3,000km 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 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. It has an estimated population of 11,500 inhabitants, though there is a large number of tourists who visit the Cook Islands in the order of 100,000 per year. Rarotonga is a round, volcanic island with an area of 67km^2 and diameter of approximately 10km. The Cook islands have set the goal of having 100% of their energy needs met by renewables by 2020. They are currently in the process of up-scaling their renewable power generation options, but have stated that their grid cannot accommodate all the renewables that are ready. Their power generation mix was effectively entirely dependent on diesel generators previously, with diesel constituting 99% of the electricity generation capacity. Electricity access on the island is almost complete at 99% coverage, and the average consumer price for electricity in 2013 was approximately $US 0.44/kWh.

Shown below is a table summarising the general island information and their respective electricity system details. Note that the ‘Demand Energy’ and ‘Demand Energy Per Capita’ refer to the electric energy consumed in a period of one year.

Island	Population	Area (km^2)	Population Density (ppl/km^2)	Demand Energy (GWh)	Demand Energy 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	1,401	82	852	7377	97	213	0.20
Gran Canaria	838,397	1,560	537	3384	4036	386	548	0.13-0.18
Rarotonga	11,500	67	157	27	2312	3	4	0.44

Table 4-3: General Island data and electricity system details

4-5 Electricity Demand of selected Islands

The averaged hourly electricity demand for 1 year will serve as an input to the model. For the islands of Gran Canaria & Rhodes, the real demand data was able to be sourced from the power producer/distributor. For Streymoy, real data was obtained for the electricity demand of the entire Faroe Island network, and this data was scaled according to the fraction of the total Faroe Island population living on Streymoy. In the case of Rarotonga, three months of the data were missing, and in this case the preceding three months of daily data were mirrored, to keep intact the seasonal variation pattern observed.

For Aruba and Sumba, the task was a little more complicated as only one day and two days worth of data respectively were able to be acquired. For Aruba, the yearly demand data was synthesised by repeating the ‘average daily demand’ profile for each day of the year, and scaling it per month, according to the total population on the island (including tourists).

For Sumba, an average daily demand profile was acquired for both a week day and weekend day from the two main grids of the island, and additionally, the monthly load variation was known for each. Thus, a 'typical' week was constructed for each grid, and repeated for an entire year, which was then scaled according to the monthly variation, and finally summed together to form the total island demand.

4-5-1 Data

Island	Data Year	Duration of data	Data Source
Streymoy	2015	Full year	[38]
Aruba	2011	One day	[39]
Sumba	2013	One day	[35]
Rhodes	2010	Full year	[40]
Gran Canaria	2015	Full year	[41]
Rarotonga	2014	9 months	[42]

Table 4-4: Demand Data details for Islands

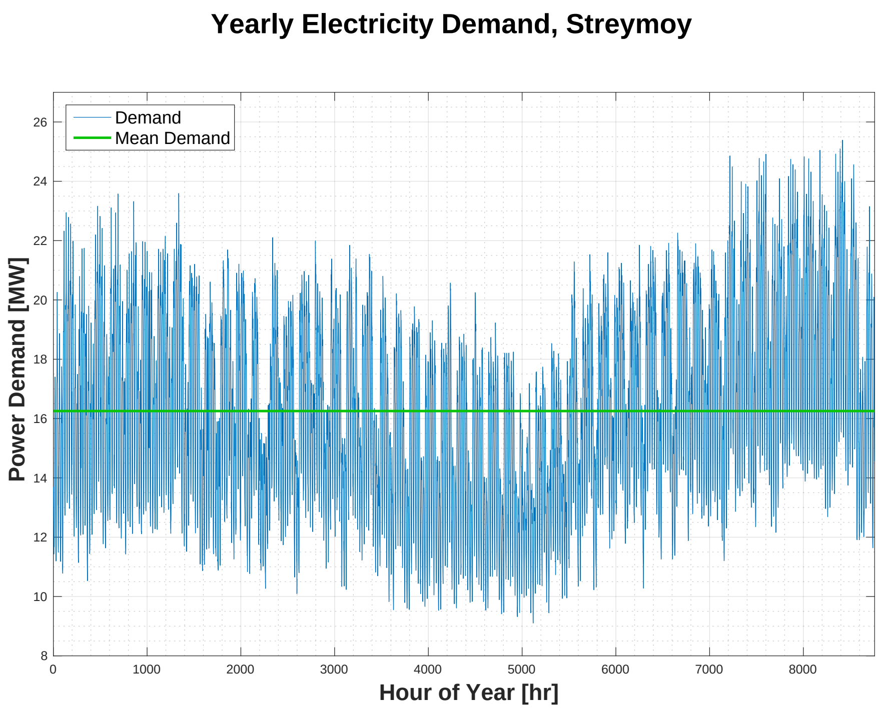


Figure 4-2: Yearly electricity demand, Streymoy

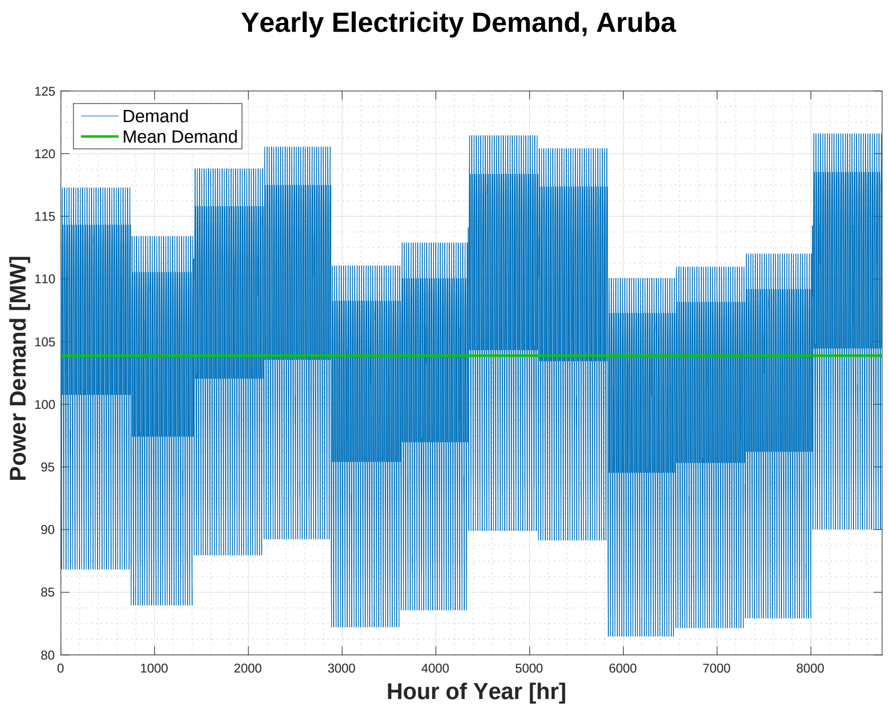


Figure 4-3: Synthesised Yearly electricity demand, Aruba

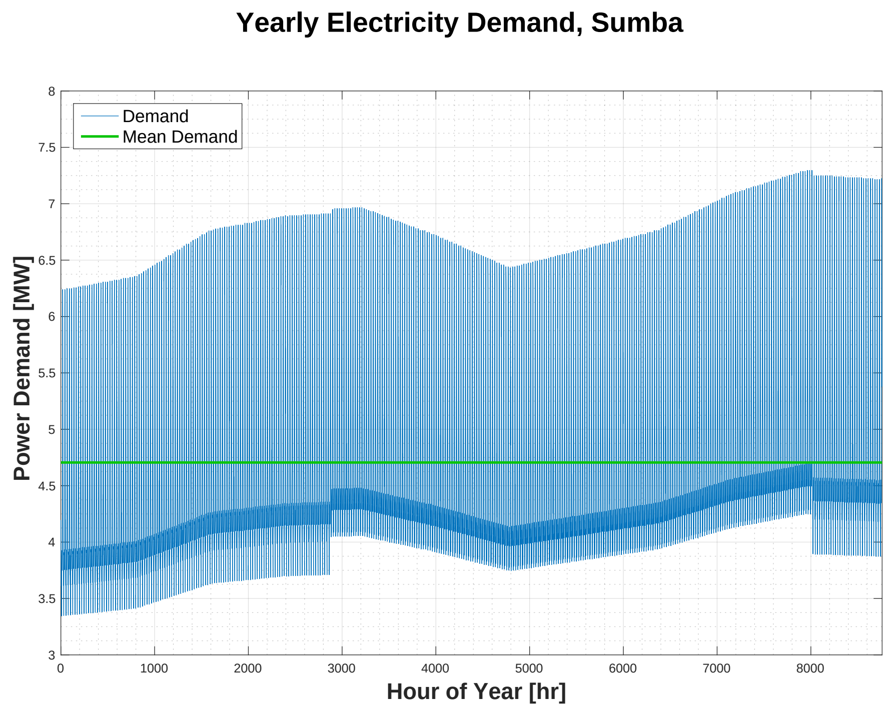


Figure 4-4: Synthesised Yearly electricity demand, Sumba

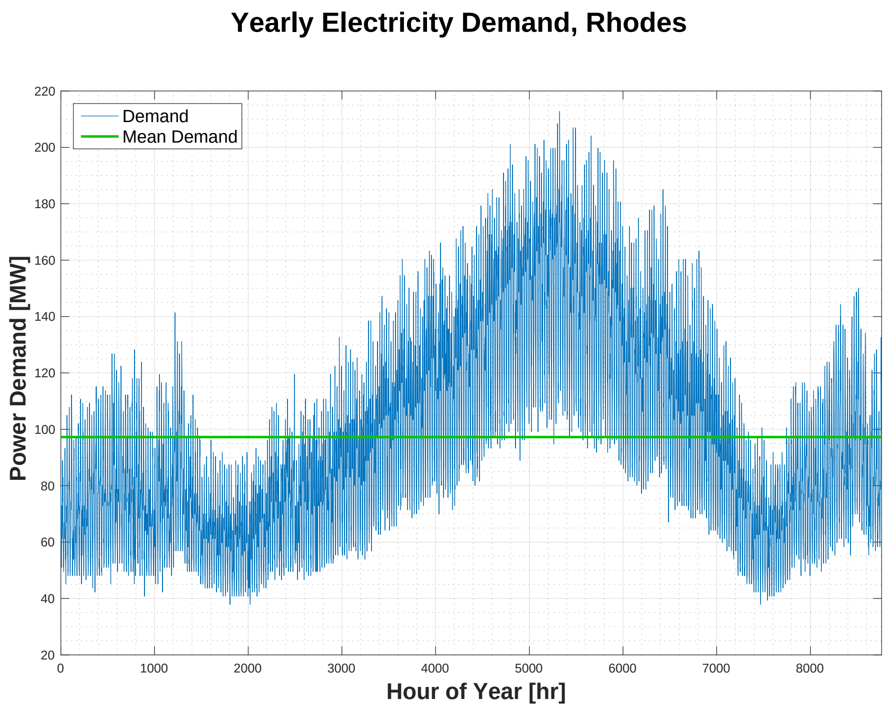


Figure 4-5: Yearly electricity demand, Rhodes

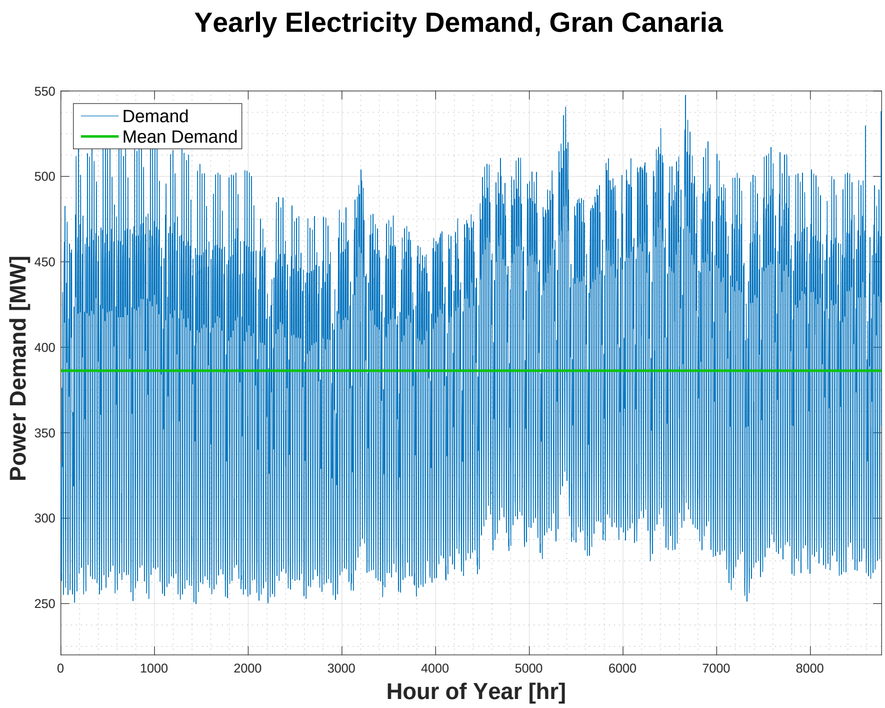


Figure 4-6: Yearly electricity demand, Gran Canaria

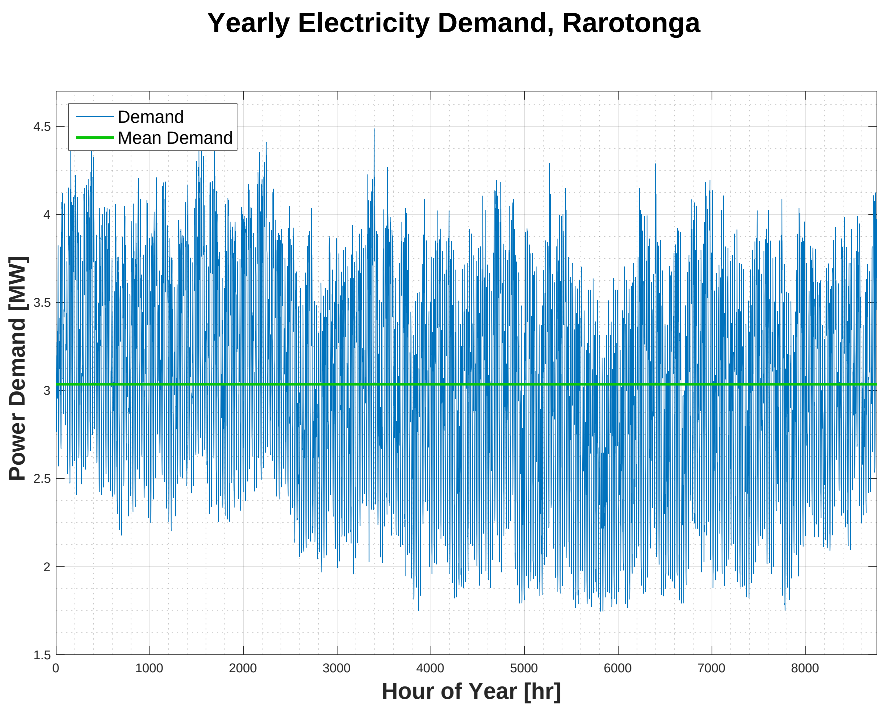
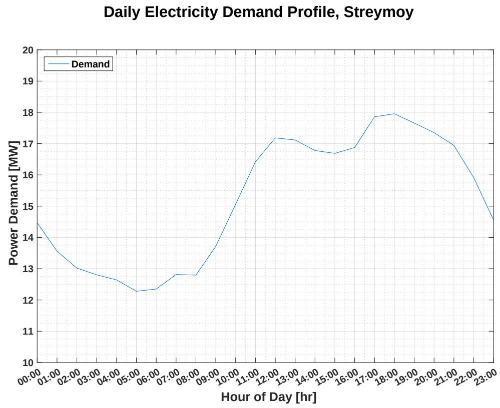


Figure 4-7: Yearly electricity demand, Rarotonga

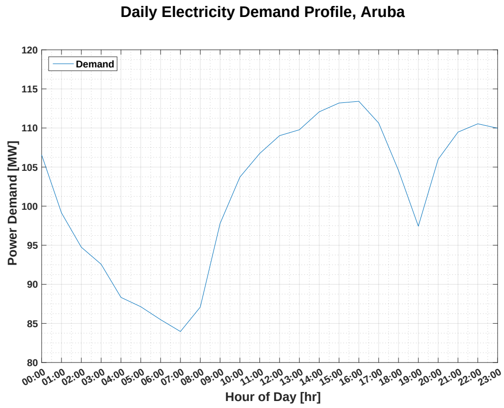
Assumptions

1. Seasonal electricity demand varies proportional to population

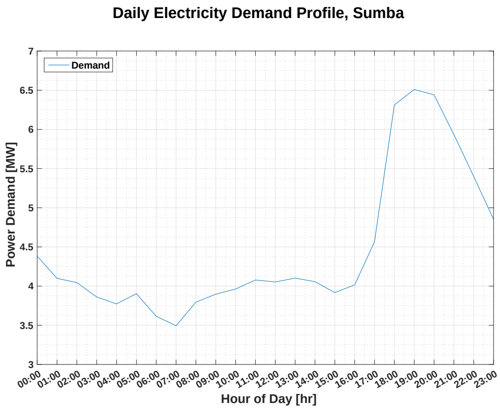
   In the absence of real yearly data for Aruba, the daily demand pattern was repeated for a year and scaled according to the monthly total population on the island, including both residents and tourists. While there is a general relation between the number of people on the island and the power demand, the decision to scale the data in this manner assumes that it is the only influencing factor, which of course is not the case in reality.



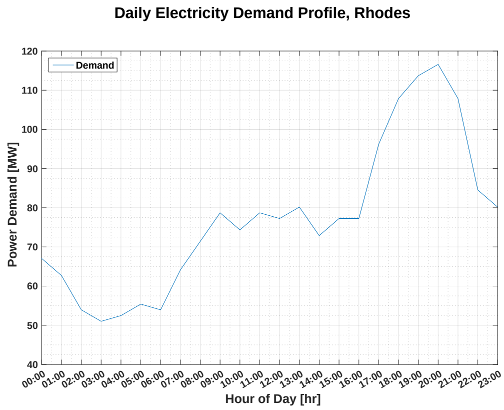
(a) Streymoy



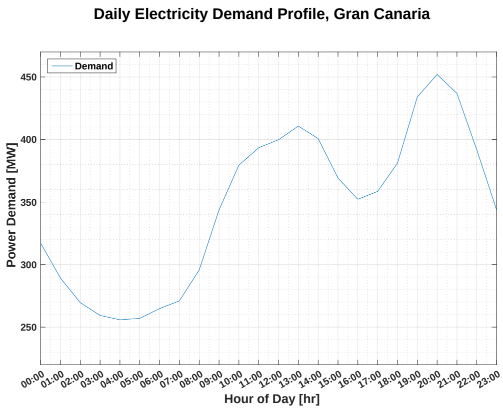
(b) Aruba



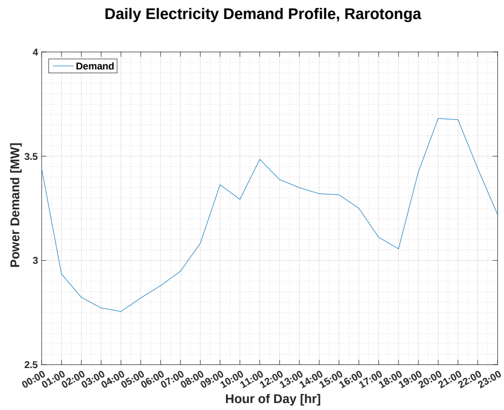
(c) Sumba



(d) Rhodes



(e) Gran Canaria



(f) Rarotonga

Figure 4-8: Daily electricity demand profiles for Islands

Chapter 5

Technology Selection

5-1 Production

5-1-1 Solar PV & Wind Energy

As two of the most mature renewable energy production technologies to date, solar PV and wind energy are natural inclusions within the model. Furthermore, it is acknowledged that the more predictable and regulated production of solar PV can be complemented by the more unpredictable and variable wind energy production.

5-1-2 Biomass

The decision was made to neglect biomass as a source for electricity production. It was envisaged that biomass would not be an ideal source given the space limitations islands are constrained by, and importing biomass fuel is less preferable than making use of indigenous resources. Secondarily, it was recognised that the environmental impacts of biomass for electricity production can be quite significant, particularly when whole tree harvesting is undertaken, rather than utilising waste biomass forms. There is some scientific research to support the notion that biomass is not strictly carbon neutral, due to differences in the carbon uptake rate when comparing mature forests with young regenerated ones [43].

5-1-3 Geothermal

Geothermal energy has been included as a potential source of electricity. Since geothermal energy is highly location-dependant - and its resource potential can only really be known after adequate exploration and investigation - the geothermal source will be treated with caution, and only implemented in the case it poses significant proven potential.

5-1-4 Hydropower

Similar to Biomass, Hydropower is renowned for its potential to have significant environmental impacts. It is however the largest-capacity means of grid-scale energy storage in use today, and has added advantages in terms of load balancing - particularly relevant for renewable electricity systems. In this model, hydropower will only be used in a closed system with pumped hydro storage.

5-1-5 Diesel Generation

The goal of this thesis is to determine cost-optimal electricity system configurations for multiple islands for increased penetrations of renewables, towards 100%. Many islands are heavily dependent on diesel generation currently, and in order to give an indication of how the transition to increased renewables can take place, diesel generation must be simulated, and has thus been included in the model.

5-1-6 Fuel Cell

The use of fuel cells has been neglected in the model due to the technology still being in a developmental phase in larger scale applications. While fuel cells possess a large, scalable potential as a renewable energy source, to date only a handful of large-scale projects have been realised, and these were all dependant on supportive policy mechanisms and subsidies.

5-1-7 Ocean Energy (Wave, thermal, tidal)

Islands inherently provide interesting opportunities for the application of ocean energy technologies. These technologies can provide continuous generation, an advantage when compared to the more intermittent modes of generation, and will be investigated and potentially added to this model by another member of the 'islands thesis group,' Leonore van Velzen.

5-2 Storage

High performance, low-cost energy storage remains a pivotal element and challenge in the transition to renewable energy systems. The selection of a particular energy storage technology is largely dependant on its application, particularly the energy capacity, and discharge rate at which they can deliver power, but also the storage duration, self-discharge rate, lifetime and of course, cost.

5-2-1 Batteries

Large-scale storage has traditionally been dominated by pumped hydro storage, however renewable energy deployment and policies to modernise electricity production and consumption are propelling numerous advances, including increased battery storage [44]. Batteries have been consistently coupled with PV systems in residential and other small-scale applications; however they have more recently gained traction in larger scale applications with hybrid renewable energy systems, and islands present unique opportunities for their implementation in this field, for reliability purposes, peak-shaving, and to aid increased integration of renewables into their grids [44]. Furthermore, with Li-ion batteries expected to decrease by 47% in the next 5 years [45], their cost viability in grid-scale storage will only become stronger. Hence, battery storage has been included in the model.

5-2-2 Pumped Hydro Storage (PHS)

Pumped hydro storage involves storing a reservoir of water that can be converted to electricity by a hydro-powered generator, and is another proven technology that has been utilised for decades, due to its large energy capacity and storage duration. More recently, it has been implemented as a means of storage to support renewable-based electricity systems to large success, such as on the islands of El Hierro and Ikaria [46, 47]. Because it has proven ability in large-scale electricity system applications, PHS has been included in this model.

5-2-3 Hydrogen (H_2)

Hydrogen storage – coupled with fuel cell technology – is receiving growing interest both scientifically and in practice, and the world's largest commercial fuel cell park, the 59MW Gyeonggi Green Energy facility is currently in operation in South Korea. In many cases though, such as that in Gyenoggi the H_2 is converted from natural gas. Also, despite regenerative hydrogen fuel cells demonstrating a higher energy stored on energy invested (ESOI) ratio, "Li-ion batteries remain energetically preferable when considering the operation of the system, as well as its manufacture, due to their higher round-trip efficiency (90%)" [48]. Because of use of natural gas rather than renewables, the efficiency difference, and the fact that large-scale applications for fuel cell technology are still under development, hydrogen storage has been omitted from the model.

5-2-4 Flywheel and Capacitors

Flywheel storage and capacitors are technologies that can be employed for rapid response to frequency deviations caused by the fluctuating nature of renewable energy technologies. They possess very high power densities, but have high self-discharge rates, low energy densities and low storage durations. Due to the nature of the modelling being performed in this model, in the minute/hour time scale, the effect of implementing these technologies would be indiscernible, and therefore they have been neglected from the model. Provision has been incorporated however for grid reinforcement and ancillary services such as those provided by these technologies, in the financial costs.

Chapter 6

Modelling

As mentioned in the **Literature Review**, there are numerous computer software tools available for the modelling of electricity systems. Although it was identified in the review by Connolly et. al [6] that the software packages TRNSYS16, HOMER and H2RES are suitable for the scale of energy system analysis undertaken in this project, these lack the flexibility of being adapted and tailored to include new energy sources such as Ocean Thermal Energy or Electric Vehicle Storage for example, which will be added to the model in concurrent and follow up research of the 'Islands Energy Group.' Furthermore, the fact that Simulink/MATLAB models are used for similar analysis in the System Integration Project 1 (SIP1) course of the Sustainable Energy Technology (SET) Master, and therefore support in this type of modelling would be accessible, the decision was made to opt for a Simulink/MATLAB model.

The model simulates (and outputs) the hourly electricity production of PV, Wind, Diesel, Pumped Hydro Storage (PHS) and Battery storage, based on their defined installed capacities, and the following (hourly) inputs:

- Solar Irradiance (W/m^2)
- Ambient Air Temperature (°C)
- Wind Speed at turbine hub height (m/s)
- Geothermal Production Potential (W)
- Electricity Demand (W)

A simple control logic is implemented, to prioritise 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 PHS system has the capacity to do so, then in turn the battery, and finally, the remainder is requested of the diesel generation. 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 meet the requested demand, the 'grid' provides the remaining energy, although this is in actuality 'unmet demand', and is classified as such in the model.

In order to optimise the system configuration based on minimised cost, specific constraints, and the respective costs of the generation technologies are introduced, with the installed capacities as the variables allowing an objective function to be defined. The details of this process are outlined in the **Optimisation** Chapter.

6-1 General Assumptions

A number of assumptions were made in order to simplify the complex task of modelling the entire electricity system of multiple islands. It is important to clearly state these assumptions and understand their potential influence on the behaviour and results of the model. The relevant implications of these assumptions are considered and explored in the **Sensitivity Analysis** and **Discussion**.

1. 'Green Field' Situation

   In modelling the electricity systems of the various islands, a zero installed capacity starting point is assumed, taking no account of the installed capacities of current power generation facilities on the islands. There are a couple of reasons why this assumption was made: Firstly, since the objective of the research was to identify cost-optimal systems based on the technologies selected and secondly, since accurate information on the current installed capacities of power generation facilities was unable to be sourced for all the islands. When looking at the transition and implementation of such an optimal system however, it is indeed relevant to know the current system configuration and its past investments, particularly in the cases where hydropower is currently installed and can provide base load renewable generation. Including the current starting point to the model could be an interesting addition for follow-up work, in investigating how the transition can optimally take place.

2. Single year analysis

   The modelling is performed on an hour to hour basis for a single year, of which the most recent data could be sourced. It is important to note that yearly demand and resource variation is not considered in this analysis. The electricity system is to be optimally sized based on the levelised costs over its lifetime, under the assumption that the same demand and production occurs over the entire lifetime of the system.

3. Feasibility of implementation

   The outcome of the simulation model is a cost-optimal sustainable energy based electricity system. This 'ideal' configuration is silent on the feasibility of implementing such a system, neglecting considerations in reality such as the local topography for PHS, grid reinforcements and balance of system requirements. In order to realise such a system, site-specific and detailed research must be undertaken, taking into account such limitations. Some calculations are performed on the feasibility of the area requirements of wind and PV, the results of which can be seen in Figure 9-10.

4. Converter Efficiencies & Losses

   Electrical efficiencies for conversion of electricity into a usable for mare considered in the wind turbines and batteries, inverter for the PV system, and also for transformers in the PHS system, however the physical and financial requirements for transformers and other ancillary services and maintaining power quality in the grid were not considered in the model. Due to the smaller distances required for power transportation on islands, transport losses are of less significance. Neglecting the grid management predicates that the actual total cost of the system would be marginally higher than determined via the model.

5. Data Reliability

   Correlation of data from different sources

   Actual measured wind speed and temperature data was used in the model, obtained from weather stations on the respective islands and accessed via the Integrated Surface Database (ISD) of the National Oceanic and Atmospheric Administration. Unfortunately, the weather stations present on the six islands investigated do not also measure solar irradiance, and therefore there was a requirement to source this data elsewhere for use in the model. The solar irradiance data was obtained from the Meteonorm database, which produces averaged data over a 10 year period to construct hourly irradiance data for a 'typical year.' A comparison was made between the real wind data and the wind data synthesised by Meteonorm, and it was found that the synthesised data did not adequately reflect the variability of the wind speeds evident in the real data. Consequently, the decision was made to use the real measured data for the wind speeds and temperature, complemented with the solar irradiance data from Meteonorm. Using these two different data sources has the implication that any physical correlation between the wind speeds, temperature and solar irradiance may not be kept intact, however in this situation it was the best option possible. Naturally, real measured data for all model inputs would be most ideal.

6-2 Production

6-2-1 Solar PV

The conversion from solar irradiance to electric power by Photovoltaic Systems was modelled according to the following equations:

$$P_{PV}(t) = A_{PV} \cdot G(t) \cdot \eta_{PV}(t) \cdot \eta_{inv} \cdot \eta_{MPPT} \cdot \eta_{other} \quad [49] \tag{6-1}$$

Where

$$\eta_{PV}(t) = \eta_{Tref} \cdot [1 - \beta_{ref}(T_C(t) - T_{ref})] \quad [50] \tag{6-2}$$

and

$$T_C(t) = T_{amb}(t) + G_t(t) \cdot e^{a+b \cdot WS(t)} \quad [51] \tag{6-3}$$

$$\eta_{inv} = 0.95 \quad [52] \tag{6-4}$$

$$\eta_{MPPT} = 0.98 \quad [49] \tag{6-5}$$

$$\eta_{other} = 0.97 \quad [53] \tag{6-6}$$

$$\eta_{Tref} = 0.15 \quad [51] \tag{6-7}$$

$$\beta_{ref} = 0.0041 \quad [51] \tag{6-8}$$

$$a = -2.98 \quad [51] \tag{6-9}$$

$$b = -0.0471 \quad [51] \tag{6-10}$$

$P_{PV}(t)$ - 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 [dim]
η_{inv} - Inverter efficiency [dim]
η_{MPPT} - PV Maximum Power Point Tracker [dim]
η_{other} - Other efficiency losses: mismatch between modules, ohmic cable losses, soiling [dim]
η_{Tref} - Module reference efficiency at reference temperature and 1000 W/m^2 irradiance [dim]
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 10m [m/s]

Assumptions

1. Mounting

   The ‘a’ and ‘b’ parameters shown in Equations 6-9 and 6-10 are defined based on the way in which the PV system is mounted, dictating the amount of air that is able to flow under the cell providing a cooling effect. Fuentes [51] presented three different mounting options, namely ‘open rack,’ ‘close roof mount,’ and ‘insulated back.’ NREL [54] states:

"Open rack parameters are best used in ground mounted situations where air can flow freely around the cells. Close roof mount is appropriate for situations where there is little clearance between the building surface and module back allowing limited air flow. Insulated back is suitable where the module is mounted directly to a building surface in a building-integrated PV (BIPV) application preventing air from flowing over the module back."

Since there is generally limited area available on most islands for large scale PV power plant installations, which would allow for open rack mounting, it was assumed that all the PV panels would be mounted on roofs, and therefore the close roof mount parameters were used. This is a conservative assumption, as PV efficiency generally decreases with increasing temperature, and a close-roof mount situation limits the amount of airflow around the modules and subsequent cooling - increasing the temperature-dependent efficiency losses. In the case of a utility-scale installation, an open mount situation would be more appropriate, resulting in reduced temperature-dependent efficiency losses and thus increased PV production.

2. Tilt

   A close roof mount situation is assumed in the PV modelling. Since global horizontal irradiance is used as am input to the model for PV production (and is not converted to direct/diffuse radiation or for a specified tilt angle), inherently a purely horizontal, 0°tilt angle is assumed. This allows for a near optimal production in islands close to the equator, however would serve a sub-optimal production in locations with more northern or southern latitudes. The energy yield reductions as a result of the horizontal orientation (when compared to a full 2-axis tracked system) range from 2.5% at latitudes of around 10°N to 25% at latitudes of 65°N [55].

6-2-2 Wind

The conversion from wind speed to electric power was modelled using the power curve of a Gamesa G87-2.0 MW turbine [56], as shown below. For use in the model, a hub height of 78 metres (4 sections) [56] was selected.

As mentioned, in order to calculate the power output from the turbine, the wind speed data (obtained at the reference height of the weather station) needs to be corrected to the turbine hub height of 78m. This conversion was made according to the common log wind profile law:

$$V(z) \quad = \quad V_{ref}\left(\frac{\ln\frac{z}{Z_0}}{\ln\frac{z_{ref}}{Z_0}}\right) \quad [57] \tag{6-11}$$

$V(z)$ - 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]

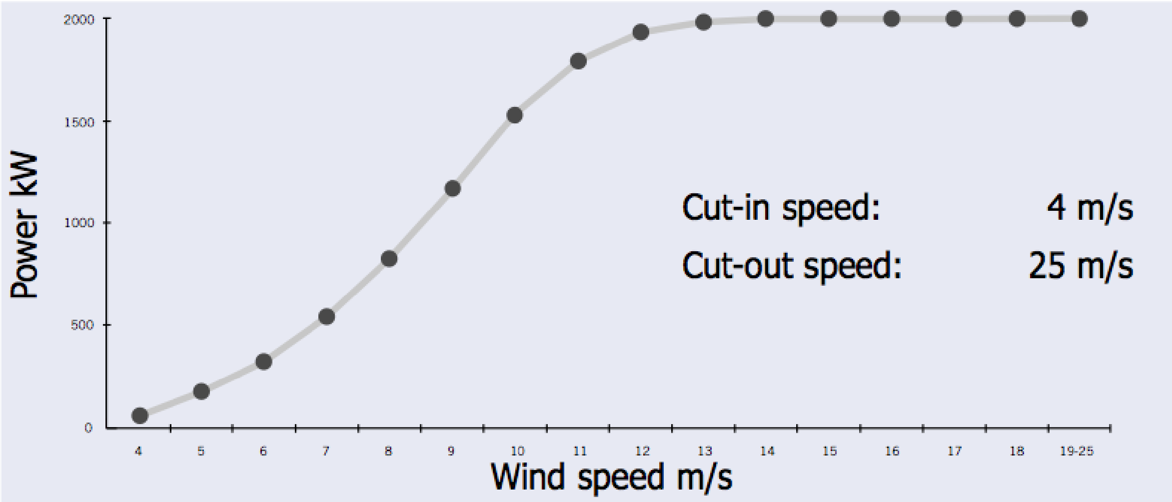


Figure 6-1: Power Curve of a Gamesa G87-2.0 MW turbine

Assumptions

1. Surface Roughness Length

   This formula assumes neutral atmospheric stability conditions under which the ground surface is neither heated nor cooled compared to the air temperature. A surface roughness length of 0.2m was used in this calculation for "agricultural land with many houses, shrubs and plants, or 8 metres tall sheltering hedgerows within a distance of about 250 metres"[57]. If a lower surface roughness was to be assumed, i.e. the measurement and turbine locations were at sea or in a less obstructed area, this would reduce the calculated wind speeds at hub height.

2. Sub-hourly Wind Speed Variation

   Wind gusts and large wind speed variations at the minute and second scale can influence the power output of a wind turbine, although this influence is considerably mitigated by the inertia of the turbine's rotor. In the model, the impact of this shorter term variation in wind speed is avoided since hourly time steps are considered, and it is assumed the turbine power output can increase from zero to rated speed within each time step. Therefore, no rate-limiting factor has been included to limit the rate at which the turbine power can vary.

6-2-3 Geothermal

Geothermal heat is able to provide constant, baseload power, by utilisng high-temperature hydrothermal resources. There is also ongoing research into the potential for hot dry rock (HDR)/enhanced geothermal systems (EGS), geopressure, and magma energy techniques [58] to do so as well, however these are not yet commercially viable [59] and hence have been omitted. The conversion of geothermal heat to electric power is modelled with the use of the **DoubletCalc** software tool, developed by TNO, in order to determine the constant electric power that could be produced, given the specific properties of the geothermal reservoir/resource on each island. The DoubletCalc tool requires the following information to be input, shown in Table 6-1 below:

Parameter	**Unit**
AQUIFER PROPERTIES	
Aquifer Permeability	mD
Aquifer gross thickness	m
Aquifer top at producer (TVD)	m
Aquifer top at injector (TVD)	m
Surface Temperature	degC
Geothermal Gradient	degC/m
Aquifer net to gross	-
Aquifer water salinity	ppm
Aquifer kh/kv ratio	-
Mid aquifer temp producer	degC
Initial aquifer pressure at producer	bar
Initial aquifer pressure at injector	bar
DOUBLET & PUMP PROPERTIES	
Exit temperature from heat exchanger	degC
Distance between wells at aquifer	m
Pump System efficiency	-
Production Pump depth	m
Pump Pressure Difference	bar
WELL PROPERTIES	
Outer diameter producer	inch
Outer diameter injector	inch
Skin Producer	-
Skin Injector	-
Penetration angle producer	inch
Penetration angle injector	inch
skin due to penetration angle producer	-
skin due to penetration angle injector	-

Table 6-1: Required parameters for calculation of Geothermal Power production using DoubletCalc software

6-2-4 Diesel Generation

Electricity production via diesel generators was modelled as a dispatchable resource, with the diesel generators able to provide any amount of electricity required, below 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 partial loads at lower fuel efficiencies. 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) and the amount of electric energy produced from the generation. Since the model operates with hourly time steps, the diesel/oil based generator(s) present in the system are not limited by their ramp up/down rates, and can ramp up/down from zero to rated capacity (and vice versa) within one hour [60]. Hence, no rate-limiting factor has been included in the model.

6-3 Storage

6-3-1 Battery

Lithium-ion battery technology has been selected for implementation in this model, due to Lithium-ion cells exhibiting relatively high energy and power densities, and the fact that they can be produced and used safely, without the use of toxic chemicals or rare metals. Furthermore, Lithium-ion is becoming the standard for grid-scale storage applications, and their costs are continuing to decrease.

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 behaviour 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 project a basic battery model has been developed, simplifying the voltage and current relationship present in batteries when charging, by relating the maximum charge rate with the state of charge (SOC).

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 1C charge rate for example, would fully charge the battery in 1 hour, a 0.5C rate in 2 hours, and so on. This is not exactly what occurs in reality, as is seen in Figure 6-2, where the charging behaviour of a Lithium-ion battery is characterised by four stages, and always requires at least 3 hours to reach a full state of charge. The charging behaviour is summarised as follows: Prior to Stage 1, a trickle charge is applied to restore the deeply depleted cells, which are usually below 3V, at around 0.1C. Then in Stage 1, a constant current is applied, in the 0.2-1C range, which sees the cell voltage rapidly shoot up. Once the cell voltage stabilises at its nominal value of around 4.2V, saturation charging takes place in Stage 2. Here, the voltage remains constant while the current decreases. When the current decreases to 3% of its rated current, the battery is full, and in Stage 4 an occasional top-up charge will be applied to counter for the voltage drop due to self-discharge.

The state of charge (SOC) of the battery while being charged, does not increase linearly over time, even under a constant charging rate, as shown below in Figure 6-3. This relationship has been approximated and used to represent the charging behaviour of the battery in a simplified way, by breaking this curve into three linear lines at hourly intervals. Consequently, the battery can be fully charged in 3 hours, 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 0.8C, 0.15C and 0.05C respectively. Naturally, when charging at a lower rate than the

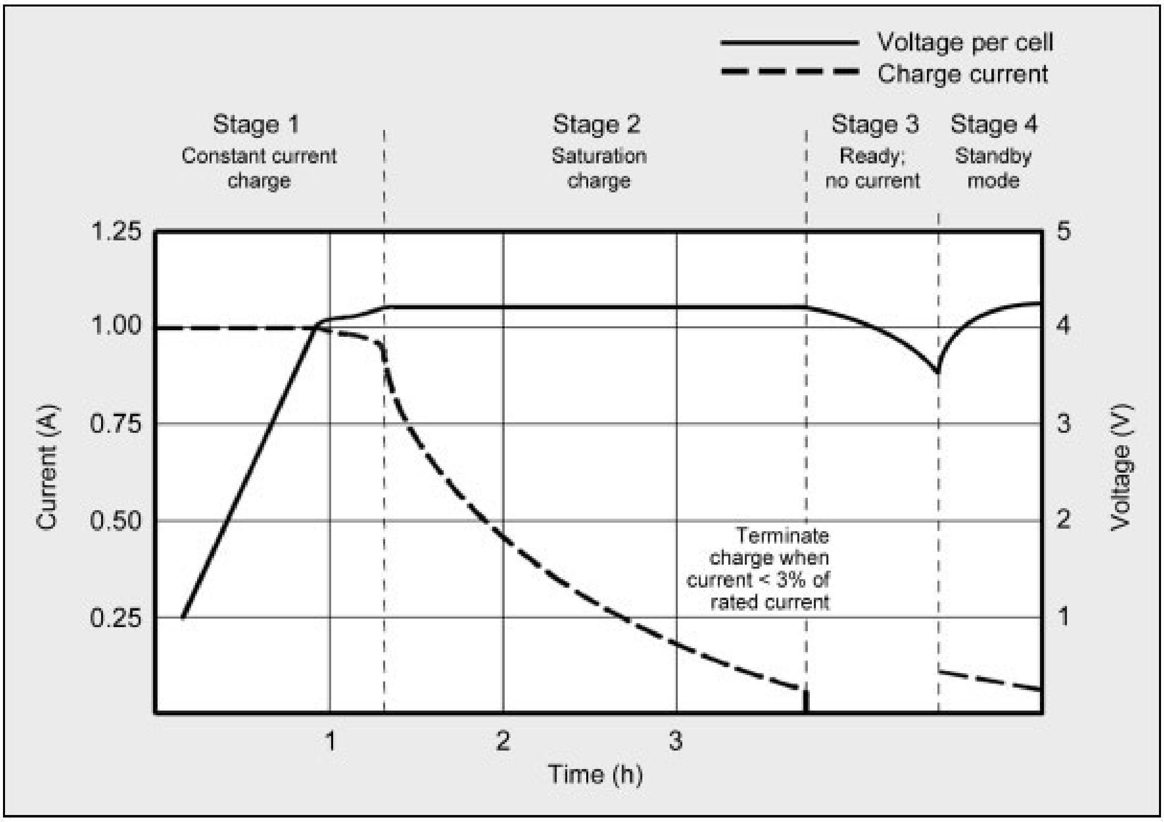


Figure 6-2: Lithium-ion Battery Charging Behaviour/Stages [61]

corresponding maximum charging rate, the time taken to fully charge the battery is longer. The approximated charging behaviour can be seen in Figure 6-4. It is important here also to note, that the assumption of having a constant charge rate during the hourly intervals in the model would be quite difficult in practice, due to the fact that renewable production varies on a much shorter time scale than this, in the scale of minutes, or even seconds.

For discharging, the relationship between the SOC of the battery and the 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. This point can be seen to occur around the 90% discharge point (1800mAh point for the 0.2C black line) in Figure 6-5 below. Furthermore, batteries are prone to self-discharging, and Lithium-ion batteries are known to self-discharge at a rate of 2-3% per month [62]. A self discharge rate of 2.5% per month has been incorporated into the battery model, scaled linearly per hour, i.e. 2.5%/(30*24) per hour.

Assumptions

1. Initial SOC

   An initial SOC of 80% was assumed for the battery system in the model. No constraint has been implemented to require the final SOC of the battery to also be at 80% at the

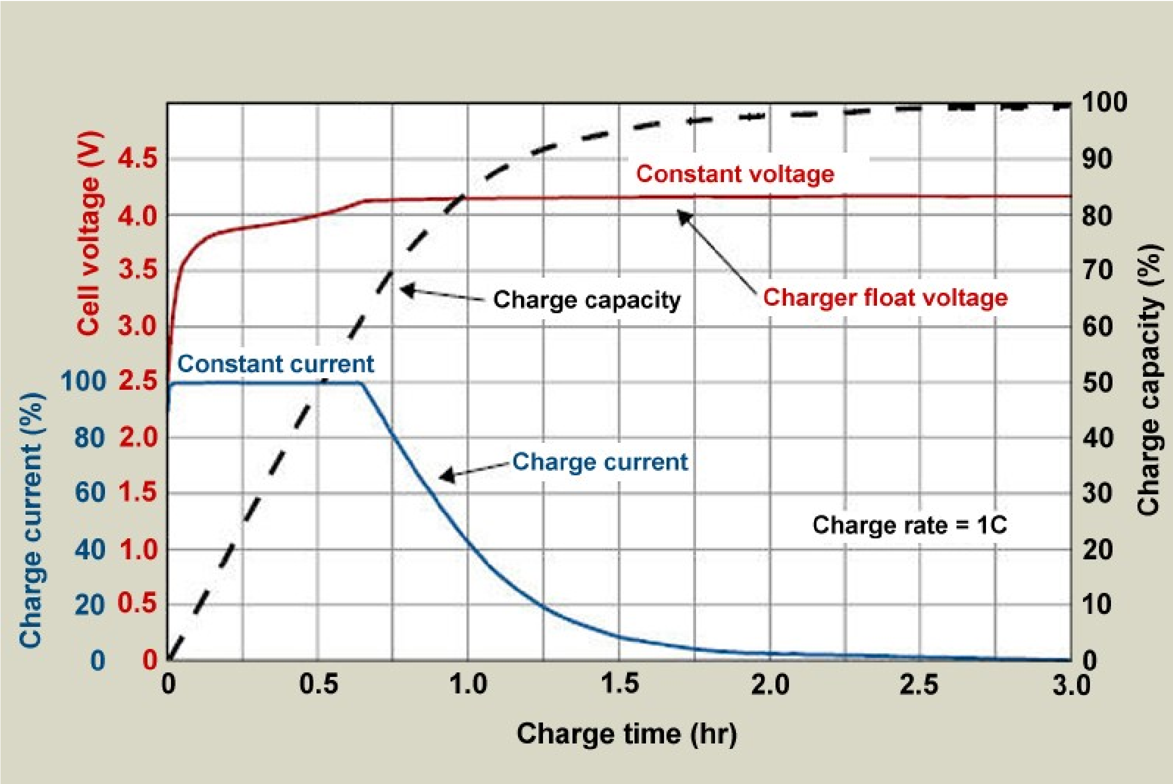


Figure 6-3: Lithium-ion cell State Of Charge (indicated as charge capacity) increase with constant charging rate of 1C applied [61]

end of the simulation, however since it is expected that the battery will serve a relatively large number of cycles, the initial and final SOC are fairly irrelevant.

2. Discharge rate influence on total discharge capacity

   The total discharge energy capacity of a battery is influenced by the rate at which it is discharged. Generally, the total discharge capacity is reduced when discharged at rates greater than 0.2C and battery manufacturers typically specify the capacity of batteries at a 0.2C discharge rate [64]. 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 1C, the battery capacity is marginally reduced, by 1.8% of its nominal capacity [65]. Since this simulation model runs with 1 hour time steps, it logically follows that the maximum amount of energy that can be released by the battery in each one hour time step cannot exceed the battery capacity. It is therefore safe to assume that a 1C discharge rate will not be exceeded. 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. This assumption disregards the use of the battery for other functions/services such as frequency regulation, voltage support, congestion relief, power reliability etc. that may require high power for durations in the scale of seconds to minutes, at discharge rates in excess of the 1C limit taken here.

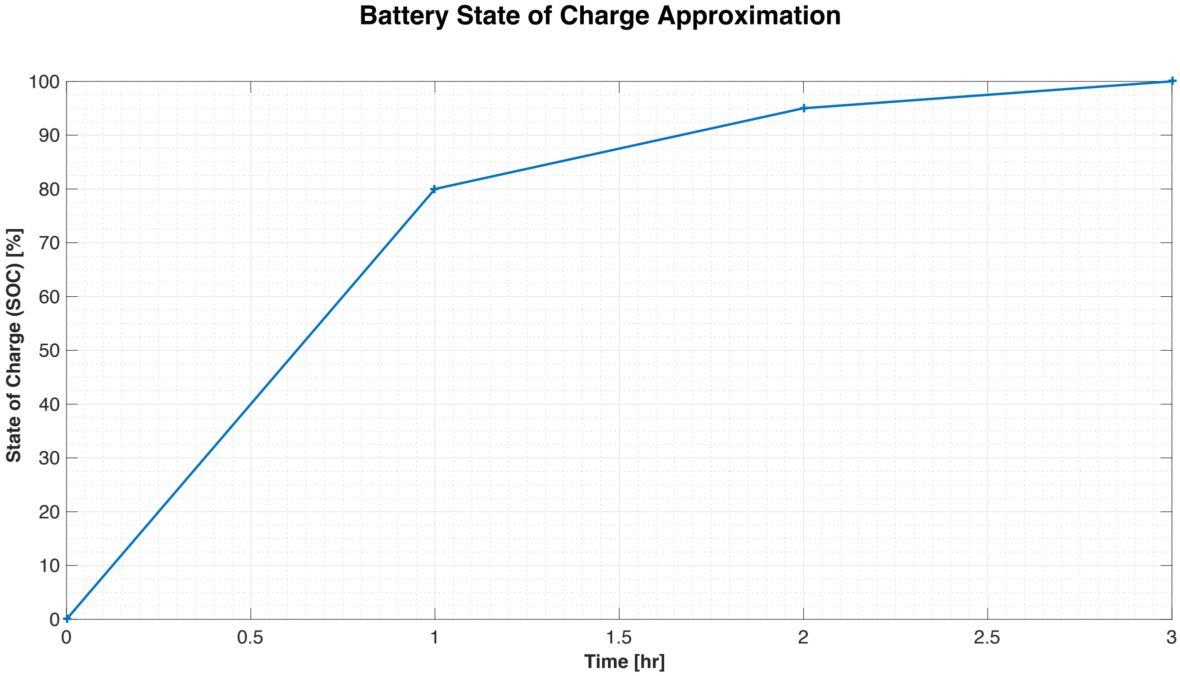


Figure 6-4: Approximation of State of Charge behaviour over time, During Charging

3. Charge rate influence on battery life

   Unlike the discharge rate, increasing the charging rate to greater than 1C does not significantly affect the total capacity of Lithium-ion batteries. By doing so, the 1st (constant-current) stage of charging time is reduced, but the overall charge cycle time is not reduced because the percentage of time in the 2nd (constant voltage) stage increases proportionately [64]. Furthermore, battery manufacturers recommend charging at 0.8C or below in order to prolong battery life. Since the charging rate has been limited in this model to a maximum of 0.8C, it is assumed that any battery degradation negatively affecting the battery life due to charging rate, can be neglected.

4. Charge/Discharge Efficiency

   The round-trip efficiency of Lithium-ion batteries is very high, with a charge efficiency of close to 100% [61]. The amount of energy able to be discharged from the battery, is dependent on the discharge rate, as previously mentioned. At a discharge rate of 1C, the total discharge capacity, and thus discharge efficiency, is reduced by a factor of 1.8%. 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%. Note however that a (albeit low) self-discharge rate is also included, further reducing the efficiency in the case it is sitting for prolonged periods without being charged or discharged.

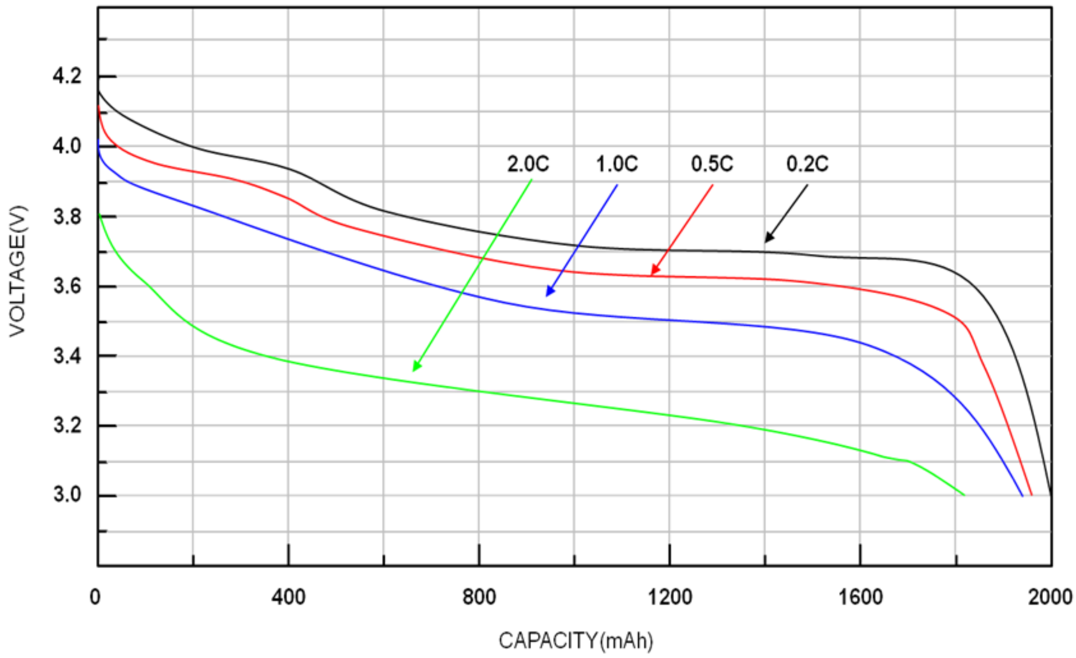


Figure 6-5: Discharge curve of a Lithium-ion Battery at varied constant Discharge Rates [63]

5. Temperature effects on battery capacity and cycle life

   The total discharge energy capacity of a battery is highly influenced by the temperature of the environment in which it is operating. At very low temperatures, Lithium-ion batteries suffer from Lithium plating of the anode causing a permanent reduction in capacity. At the upper extreme, the active chemicals may break down destroying the battery [62]. Between this range, battery performace generally improves at increased temperatures, as can be seen below in Figure 6-6. All batteries achieve optimum service life when used at 20°C [66], and it has been assumed in this model that the battery system will be operated in constant conditions of 20°C.

6. Depth of discharge (and charge) influence on battery life

   Most Lithium-ion cells discharge to around 3.0V. Discharging beyond this would see the voltage drop off very rapidly, which is unhealthy for the battery. To protect the battery from over-discharging, most devices prevent discharging beyond their specified 'end of discharge' voltage [67]. As can be seen in Figure 6-7 below, restricting the permitted DoD from 100% to 60% of its capacity makes little difference to the cycle life of the battery. However, restricting the DoD to less than 60% of its capacity results in more substantial increases in cycle life. An optimal balance exists between maximising energy output per cycle - therefore reducing the amount of batteries required to meet a certain demand - and prolonging the life of the battery by limiting the depth of discharge. Additionally, it is not desirable to charge a battery right up to 100% SOC, as the high voltage stresses the battery, and battery life can be prolonged by limiting the 'full' threshold [61]. In this model, fully charging the battery has been permitted and a DoD limit of 90% (minimum SOC of 10%) has been set.

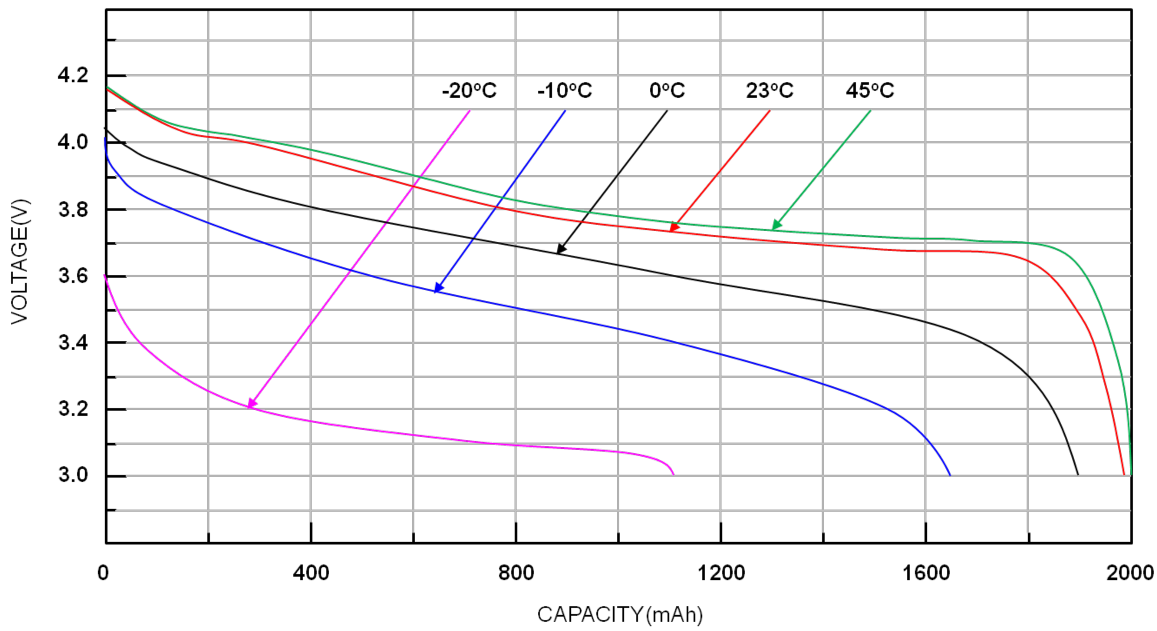


Figure 6-6: Discharge curve of a Lithium-ion Battery at various Temperatures [63]

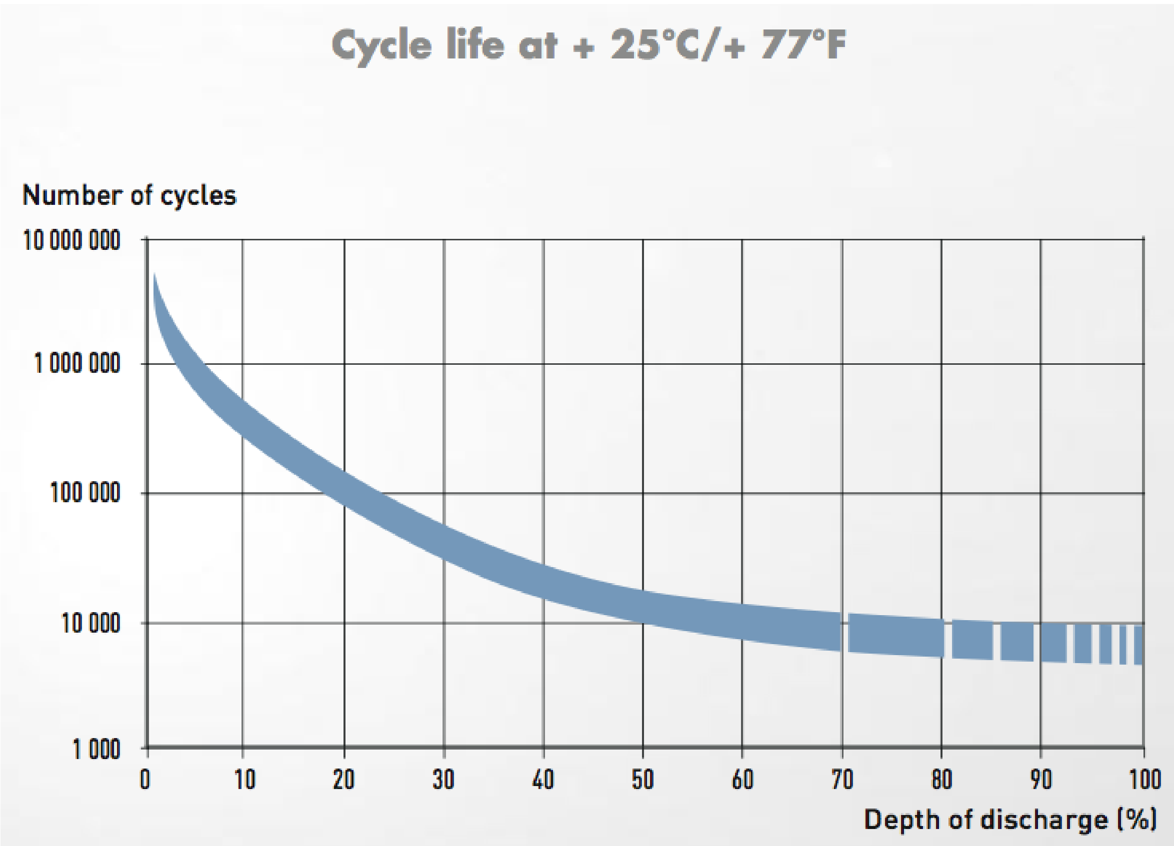


Figure 6-7: Battery Life Cycles based on Depth of Discharge (DoD) [68]

6-3-2 Pumped Hydro Storage (PHS)

The implementation and selection of turbines for pumped hydro storage (PHS) is highly dependent on the topography of the site. As shown in Figure 6-8 below, the most suitable turbines for applications with high head levels of greater than 100m are the Francis and Pelton turbines, with the Pelton turbines most suitable for very high head levels.

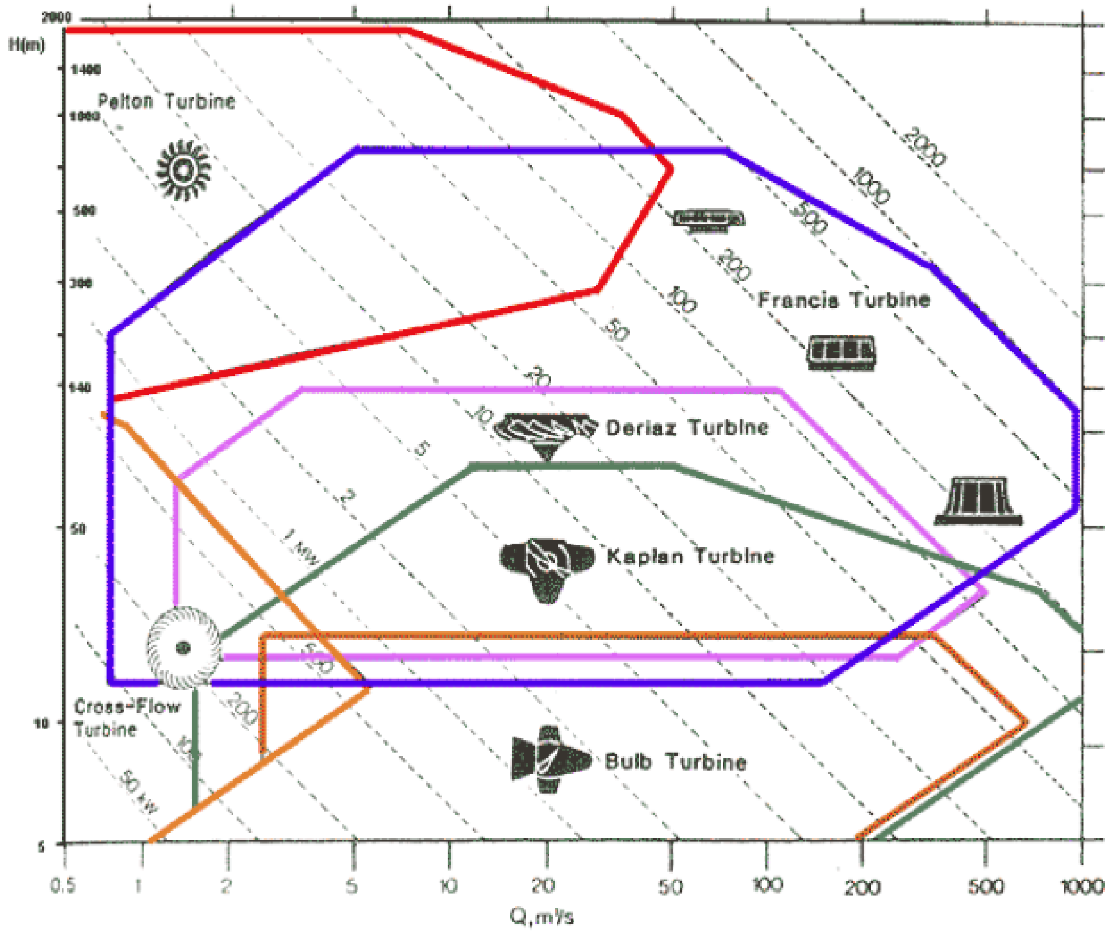


Figure 6-8: Comparison of various Turbine Application Ranges

A secondary, and equally important consideration is the efficiency performance of the turbines in their planned operation range. As can be seen in Figure 6-9, the Pelton turbines perform considerably better than the Francis turbines at lower proportional flow rates. This is an inherent physical characteristic of the turbines with significant implications for operation in renewable electricity systems: a larger operation range at high efficiency is highly preferable, as it allows for both small and large renewable electricity deficits to be met in an efficient manner, maximising the overall efficiency of the PHS. As a result of this, and the fact that Pelton turbines have been implemented in two key PHS projects on islands to date, namely on El Hierro and Ikaria [46, 47], Pelton turbines have been selected for implementation in the model. The potential effects of the PHS system turbine selection is also addressed in the Discussion section.

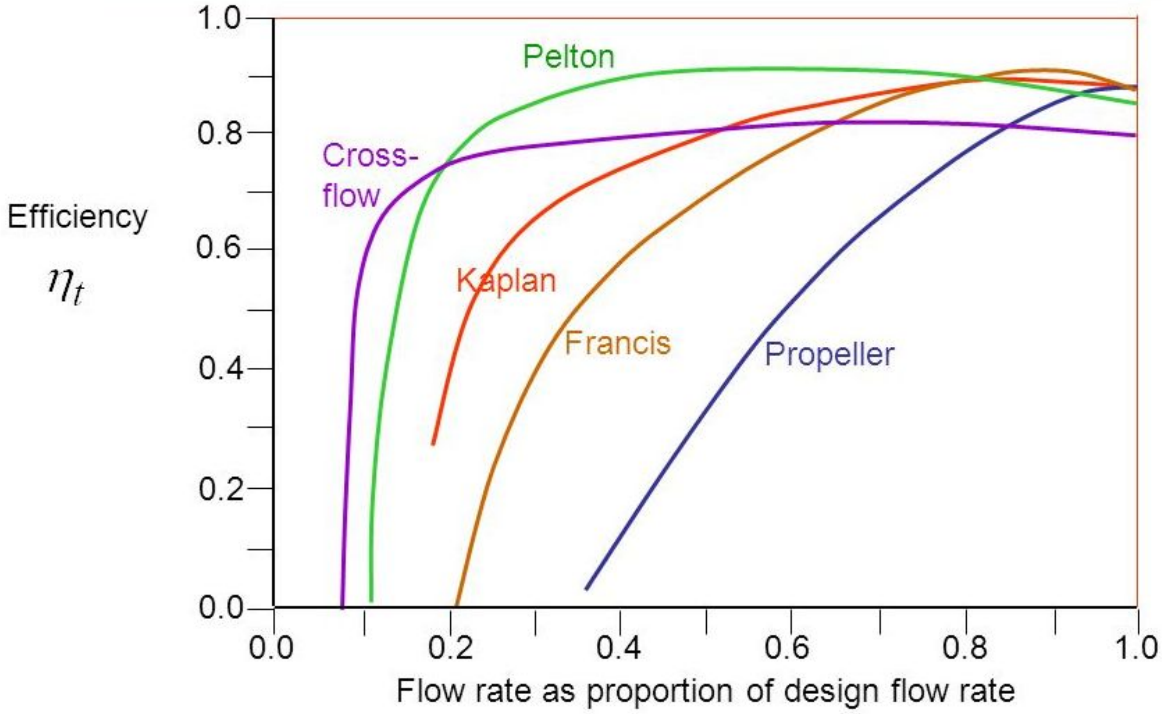


Figure 6-9: Comparison of Turbine Efficiencies as proportion of Design Flow Rate

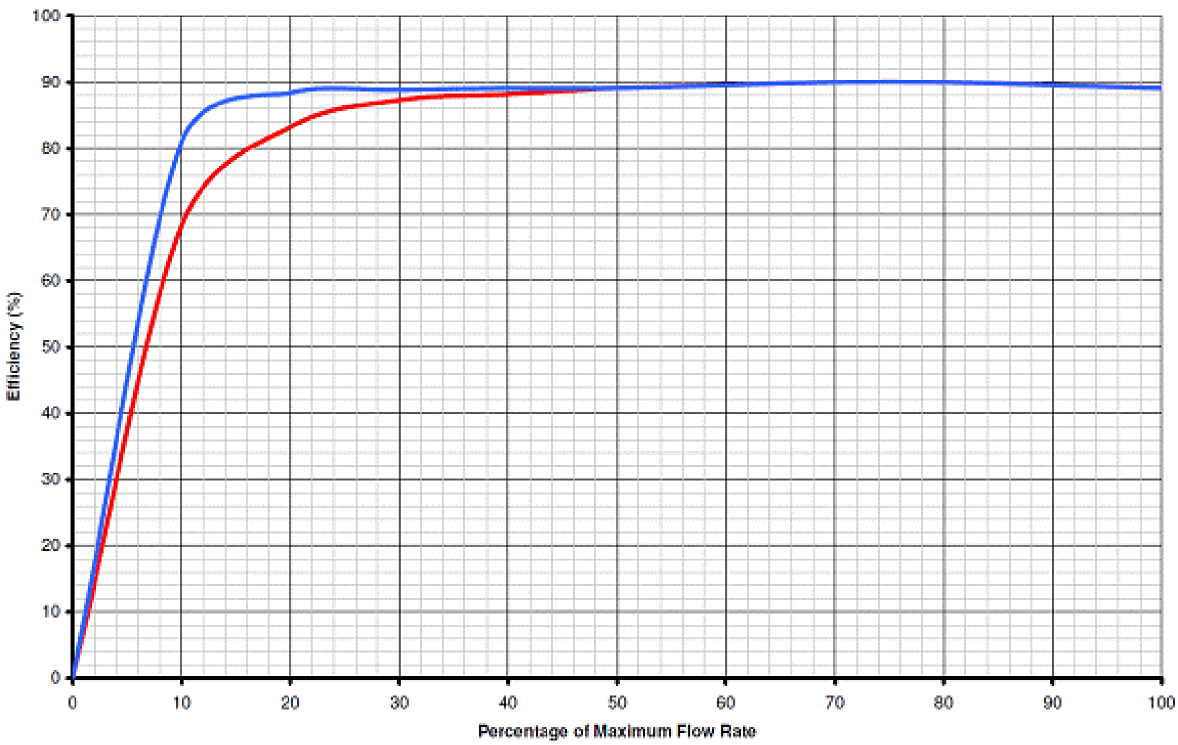


Figure 6-10: Pelton Turbine Efficiencies as proportion of Design Flow Rate

The efficiency of the Pelton turbine is seen to be effectively constant around 90%, at flow rates greater than 10% of its rated flow [47], as can also be seen in Figure 6-10. Additionally, the minimum flow rate required for hydropower generation has been set at 10% of rated flow.

The pumped hydro storage system is modelled according to the following equations, with the respective efficiencies sourced from [47]:

When producing power:

$$P_{gen}(t) = \rho_w \cdot g \cdot H \cdot q \cdot \eta_t \cdot \eta_g \cdot \eta_{tr} \tag{6-12}$$

Where

$$\eta_t = 0.90 \tag{6-13}$$

$$\eta_g = 0.95 \tag{6-14}$$

$$\eta_{tr} = 0.987 \tag{6-15}$$

When pumping water for storage:

$$P_{st} = \frac{\rho_w \cdot g \cdot H \cdot q}{\eta_p \cdot \eta_m \cdot \eta_{tr}} \tag{6-16}$$

Where

$$\eta_p = 0.74 \tag{6-17}$$

$$\eta_m = 0.96 \tag{6-18}$$

$$\eta_{tr} = 0.990 \tag{6-19}$$

$P_{gen}(t)$ - 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]
g - Flow rate [m^3/s]
η_t - Turbine efficiency [dim]
η_g - Generator efficiency [dim]
η_{tr} - Transformer efficiency [dim]
η_p - Pump efficiency [dim]

Assumptions

1. Initial reservoir levels

   The levels of both the upper and lower reservoirs were assumed to be at half of their maximum capacity.

2. Head Height between reservoirs

   Due to the variety of influencing factors at play and the sheer complexity of trying to site an ideal location for a pumped hydro storage system in reality, a rudimentary assumption was made, that a theoretical PHS system could be realised utilising a head height (H) (the height difference between the upper and lower reservoirs) of half of the highest elevation on the island. This assumption neglects the local topography and physical forms or limitations present on the islands, but allows for the very basic influence of altitude difference to be incorporated.

3. Rain and evaporation

   It was assumed that the volume of water in both the upper and lower reservoirs remains constant when not used for power generation or storage. This assumption neglects the influence of rain and evaporation of water on the reservoir's volume.

4. Pumping capacity

   It was assumed that the pump system's minimum and maximum power capacity are the same as that of the turbine. The efficiencies differ for generation and pumping as outlined above. The assumption that the pump system is sized the same as the turbine capacity however neglects the fact that the turbine and pumping systems are usually sized separately. This would have necessitated the pump system to be included as a technology in the optimisation however, which was not preferable. As such, a specific pump system/technology has not been specified, and it is assumed the costs of the pump system are included in the costs of civil works, reservoir construction and other equipment for PHS systems.

5. Usable reservoir capacity

   It was assumed in the model that the entire reservoir volume could be utilised, provided that the minimum flow for generation and pumping could be respectively met for the entire hourly time step. This assumption neglects the 'dead' or 'inactive' volume of water that usually exists in a reservoir in order to allow for sediments to settle. It also neglects the possibility for the pump/turbine to operate at the minimum flow rate for sub-hourly intervals.

Chapter 7

Resource Assessment

7-1 Solar Irradiation

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 synthesised irradiation data from Meteonorm was the best available option. Shown below in Figure 7-1 is the monthly averaged irradiation per day. Note that total global horizontal irradiation (Gh) was used for the model.

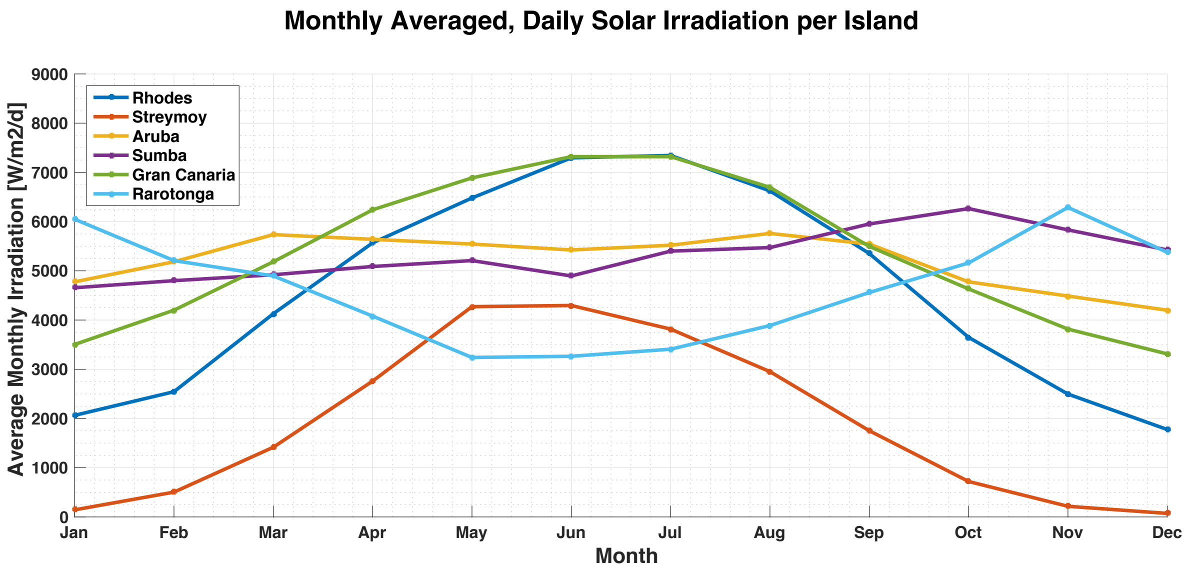


Figure 7-1: Solar Irradiation for selected islands in W/m^2/d

7-2 Wind

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). 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 is explained further in the **Modelling** section.

Shown below in Figure 7-2 is the monthly average wind speed for the selected islands.

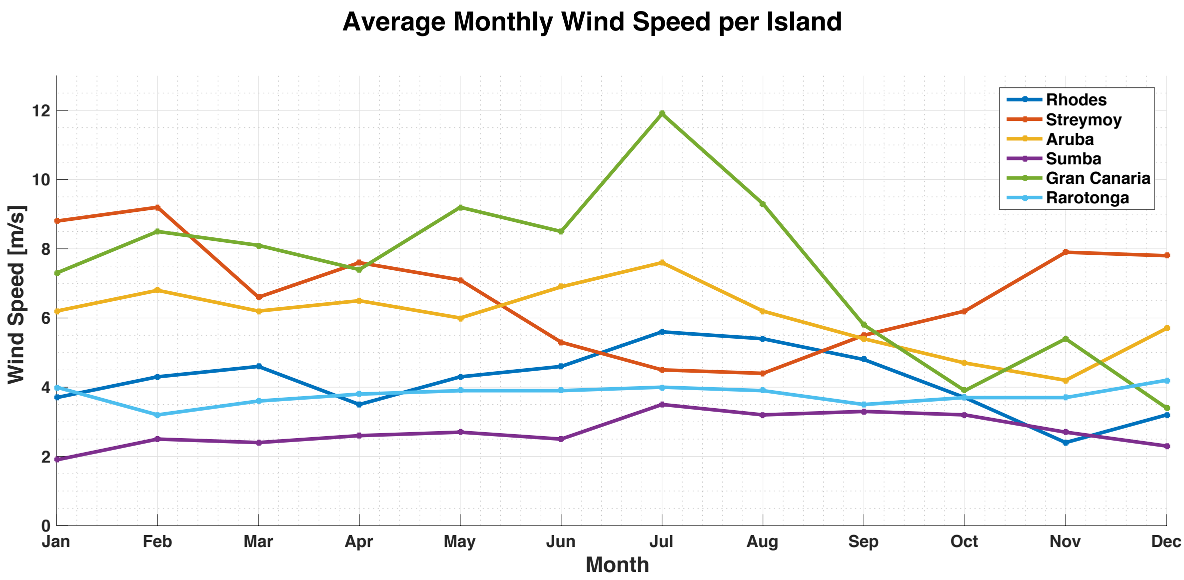


Figure 7-2: Average Wind Speeds for selected islands in m/s

7-3 Geothermal

Utilising geothermal energy for hydrothermal electricity production is critically dependent on the geotechnical properties of the hydrothermal reservoir. For a project to be viable, detailed analysis/exploration must be undertaken, in order to ascertain the dimensions and properties of the underground reservoir. Without this knowledge, it is effectively impossible to identify a suitable location for a plant, even given the general indication of high potential areas such as those with volcanic activity or along the Pacific 'Ring of Fire.'

Rhodes

A review of geothermal exploration studies performed in Greece [69] found that "high-temperature (>200°C) geothermal resources are found on the islands of Milos and Nisyros, and inferred also in Santorini based on its volcanic activity." Furthermore, "low-temperature (<100°C) thermal aquifers, whose water chemistry indicates the possible existence of deeper, intermediate- temperature (100–200°C) resources, have been found on the islands of Chios, Lesvos and Samothraki" [69]. However, there is no indication that Rhodes has any reservoirs suitable for geothermal electricity production. This was confirmed through email correspondence with a professor from the Technological Educational Institute of Crete, who explained "apart from the islands you already discovered with your research, namely Milos, Nisiros and Lesvos, there is no other high or medium enthalpy geothermal field discovered in Greece anywhere else, including Rhodes" [70].

Streymoy

The search for information regarding the geothermal potential on Streymoy was ultimately unsuccessful. Although neighbouring Iceland is renowned for its abundant geothermal resource and utilisation, there is no indication (yet) that the Faroe Islands share similarly favourable conditions.

Aruba

There is a general indication that there are no hot springs or evidence of surface geothermal activity on Aruba or neighbouring Curaçao [71], rendering conventional geothermal energy for electricity production infeasible. Three petroleum wells were drilled off the coast of Aruba from 1989-1990 [71] and these indicated a relatively low geothermal temperature gradient of 20°C/km, meaning that a well of around 10 km depth would be required in order to reach the required temperatures of 200-250°C necessary to even explore hot dry rock (HDR) applications.

Sumba

A preliminary renewable energy resource assessment - for the Indonesian islands of Sumba and Buru - was commissioned by Hivos and carried out by Winrock International [72] in 2010. This report found that for the island of Sumba there was "no geothermal potential identified."

Gran Canaria

The island of Gran Canaria presents an interesting situation in regard to geothermal energy. It has long been thought that Gran Canaria has geothermal energy potential, and it is classed as a volcanically active island. Furthermore, geothermal reservoirs have been found at depths around 1500m, with moderate temperatures of 50-70°C. In 2008, the Australian company Petratherm was granted 4 exploration licences in Tenerife and Gran Canaria, and in 2010 it was granted permission to convert the exploration licences into investigation licences. The plan was then to have a gradient drilling campaign in 2012, and if successful, the first geothermal well in 2013 [73]. It appears however that these investigations were unsuccessful, as the status of the project has remained unchanged on the company's website, no information on the project can be found anywhere else, and the company failed to respond to contact requests on the project. This tends to suggest that despite the existence of some geothermal resource, utilising it for electricity production remains non-viable.

Rarotonga

A report on geothermal resources in the Pacific Islands [74] found that in the Cook Islands, no geothermal locations have been identified, and the development potential is low. Hence, geothermal energy for electricity generation appears infeasible.

7-4 Pumped Hydro Storage (PHS)

As previously mentioned, 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 below.

Island	Highest Elevation (m)	PHS system Head Height (m)
Streymoy	789	394.5
Aruba	189	94.5
Sumba	1225	612.5
Rhodes	1216	608
Gran Canaria	1949	974.5
Rarotonga	652	326

Table 7-1: PHS system Head Height on islands

Chapter 8

Optimisation

8-1 Problem Formulation

In order to answer the primary research question of this thesis - determining cost-optimal electricity system configurations for islands - a clear definition of what constitutes the costs of an electricity system is required.

A well-established metric in the energy field for quantifying and comparing the costs of electricity generation technologies is the Levelised 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), which are then divided by the total energy production over the course of its lifetime [75]. 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 levelised cost of storage, in order to assess the Levelised Cost of System (LCOS).

8-1-1 Levelised 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 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. Furthermore, it does not allocate costs for the curtailment of power, which would be required in situations of large penetration of renewables as investigated here. Nonetheless, the LCOS does serve as a useful basis for the comparison of various electricity systems - the intention of this research.

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

$$LCOS \quad \frac{[USD]}{[kWh]} \quad = \quad \frac{\sum_{t=0}^{T} \frac{I_t \quad + \quad FM_t \quad + \quad VM_t \quad + \quad F_t}{(1+r)^t}}{\sum_{t=0}^{T} \frac{E_t}{(1+r)^t}} \tag{8-1}$$

Where:

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

8-1-2 Decision Variables

The system variables required to be optimised are:

$\mathbf{IC_{PV}}$ - The installed capacity of PV power [MW]

$\mathbf{IC_{W}}$ - The installed capacity of wind power [MW]

$\mathbf{IC_{PHS}}$ - The installed capacity of the PHS turbine/pump power [MW]

$\mathbf{IC_{res,up}}$ - The installed energy capacity of the PHS system upper reservoir [MWh]

$\mathbf{IC_{res,low}}$ - The installed energy capacity of the PHS system lower reservoir [MWh]

$\mathbf{IC_{B}}$ - The installed energy capacity of the battery system [MWh]

$\mathbf{IC_{D}}$ - The installed capacity of diesel generators [MW]

8-1-3 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 optimisation is to minimise the objective (cost) function, while meeting the specified constraints stated above.

$$LCOS = \frac{\sum_{t=0}^{T} \frac{IC_x(I_x)_t + IC_x(FM_x)_t + E_{x,t}(VM_x)t + E_{x,t}(F_x)_t + IC_y(I_y)_t + IC_y(FM_y)_t + \ldots}{(1+r)^t}}{\sum_{t=0}^{T} \frac{(E_{S,prod})_t}{(1+r)^t}} \tag{8-2}$$

- Investment costs are applied in [USD/installed kW] for production elements and [USD/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

8-1-4 Constraints

The objective function is subject to the following constraints:

$$IC_{PV}, IC_W, IC_{PHS}, IC_{res,up}, IC_{res,low}, IC_B, IC_D \geq 0 \tag{8-3}$$

$$E_{d,unmet} \leq 0.001 * E_{d,total} \tag{8-4}$$

$$E_D = \gamma * E_{S,prod} \tag{8-5}$$

Where

$$\gamma = 0.1, \quad 0.3, \quad 0.5, \quad 0.7, \quad 0.9 \tag{8-6}$$

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 demand energy 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 is limited backup generation reserves.

Diesel penetrations of 10%, 30%, 50%, 70%, and 90%, of the produced system energy were investigated.

8-1-5 Optimisation Method

In order to find optimal solutions to the objective function, the 'Response Optimisation' tool was utilised within the Simulink model. 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," [76]. The parameter tolerance, constraint tolerance and function tolerance were all set to 1e-3 in the Optimisation Options.

8-2 Cost Data

The following data was used for the Investment (I), Fixed Maintenance (FM), Variable Maintenance (VM) and Fuel (F) Costs:

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	[77]
Wind	1475	$US/kW	37.5	0	0	[77]
Geothermal	5450	$US/kW	0	35	0	[77]
Diesel	650	$US/kW	15	15	See Table 8-2	
***PHS Electro-mechanical equipment + O&M**	370	$US/kW	6.5	0	0	[78]
PHS - Civil works	253	$US/kWh	0	0.3	0	[45]
Battery	1054	$US/kWh	11.5	0	0	[45]

Table 8-1: Cost Data used in LCOS calculation and Optimisation

Island	Year	Annual Production from Diesel (GWh)	Annual Fuel Expenses ($US)	Fuel Cost ($US/MWh)	Reference
Streymoy	2014	150.2	25,416,000	169.2	[79]
Aruba	2011	837.5	183,010,305	218.5	[80]
Sumba	2013	21.3	6,000,000	282.0	[72]
Rhodes	2010	-	-	220.0	[81]
Gran Canaria	2015	-	-	110.0	[82]
Rarotonga	2014	27.4	7,296,201	266.5	[83]

Table 8-2: Diesel/Fuel Costs for Electricity Generation per Island

8-2-1 Assumptions

1. System Lifetime

   A system lifetime of 20 years was applied for all of the technologies used in the model. This assumption misrepresents the much longer lifetime of a PHS - often in the order of around 60-80 years - which would reduce its levelised cost.

2. Battery replacement

   A battery replacement cost was included in the upfront investment costs for the battery, which would normally take place after 10 years. This assumption neglects the fact that this investment would be made 10 years later, at a discounted cost.

3. Interest rate (r)

   An interest rate of 5% [84] was incorporated for the discounting of future costs and energy production.

4. Wind onshore

   The investment and operation & maintenance cost data for the wind turbines used in the optimisation were taken for the case of onshore wind production. This assumption neglects - as mentioned earlier - the practical feasibility of implementing these turbines on the islands investigated. In the case of offshore wind production, the costs may be higher, which could affect the composition of the optimal configuration.

5. PV utility-scale

   The investment and operation & maintenance cost data for the PV production were taken for the case of utility-scale crystalline silicon production. This somewhat conflicts with the previous assumption made in the PV modelling section where certain parameters were selected for a close-mounted rooftop scenario since it was assumed there would be limited space for utility scale PV installations. However since the total scale of production will be at utility-level, it is reasonable to assume the investments made will be collective, and large enough to warrant using cost data for that scale.

6. PHS reservoir construction & power generation costs

   In order for the PHS reservoir and power generation equipment to be sized separately via the Optimisation, the costs of these also had to be divided. This was achieved by determining the proportion of the total project costs that were dedicated to the power generation equipment, and assuming the rest was allocated to the reservoir construction, pumping equipment and other associated civil works. Power generation equipment constitutes on average 16% of the Investment Costs for large-scale hydro power projects [85]. Hence, the values of $US 370/kW and $US 253/kWh used in the Optimisation were calculated by 16% * 2312.5 for the power generation and 84% * 301.5 for the construction, pumping and civil works respectively.

   It is also worthwhile here to note that reservoir construction costs per cubic metre of capacity were unable to be sourced, and as a result the investment costs for civil works etc. were priced per kilowatt-hour of installed capacity. In converting the reservoir capacities in cubic metres to kilowatt-hours of potential energy, naturally the head height is required to be known. In the case of this project, it was assumed that the associated costs scale proportionately to the head height. This is a reasonable assumption when considering the piping, tunnel excavation, and other civil works that are influenced by head height. Furthermore, the 16%/84% breakdown would not always strictly apply, as in the Optimisation these are sized separately, meaning the ratio of turbine capacity to reservoir capacity would differ. However this breakdown was used purely to have two costs that could be applied to the respective variables.

The total investment costs for reservoir construction, pumps, and other civil works were calculated by converting the capacities of the upper and lower reservoirs to the total amount of kilowatt-hours able to be produced, and stored, according to the following formula:

$$Energy \quad Capacity \quad [J] \quad = \quad (IC_{upper} + IC_{lower}) \cdot \rho_w \cdot g \cdot H \tag{8-7}$$

Then, to convert from J to kWh, a factor of 1e-3*1/3600 was applied, and this was multiplied with the $US 1054/kWh cost stated in the table above, to determine the total investment costs for reservoir construction, associated civil works and pumping/other equipment.

7. Diesel investment costs included in LCOE

   Since the objective of this project is to determine a theoretic cost-optimal renewable-based electricity system, and also because of the difficulty of sourcing information on the size and number of existing diesel gensets on each island, the investment costs for diesel generation were also included. This assumption neglects the cost savings that would be made by making use of the existing diesel generators on these islands, however the fuel costs for diesel are of much more significance over the lifetime of their operation anyway.

8. Identical costs for all islands

   It was assumed that (apart from the Diesel costs which were determined case specifically) the costs for the technologies are equal for every island. Naturally of course it is likely that there is some variation in these costs, particularly with the transport of equipment and machinery and the general project logistics per island. Sourcing cost data for larger-scale projects on these islands could allow for more site-specific comparative costs to be included.

Chapter 9

Results

9-1 Optimal LCOS Values with increasing RES Share

Business Case for Renewables

The results of the optimisation clearly mount a strong supporting case for the integration of renewable electricity generation into their respective island grids. As shown in Figure 9-1, the levelised system costs (LCOS) for electricity generation decrease considerably with increasing renewable energy penetration, up to an optimal point in the range of 40% (in the case of Sumba), to 80% (in the case of Aruba). This optimal RES penetration range is fairly consistent with results obtained in literature for island systems, with RES penetrations of: 61% on the Island of El Hierro [13], 55-60% on Dongfushan Island [86], 78%, 92% and 85% on the islands of Kithnos, Ikaria, and Karpathos respectively (including maximum RES penetration as an optimisation criteria) [87], and 77% on a small island in China [88]. 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 [13], although considerably lower than values obtained in other studies which were found, in the range of $US 0.7-1.4/kWh in [11] [89] [8]. 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.

Beyond this optimal point, 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. Furthermore, the costs of Li-ion batteries are rapidly decreasing, a fact which could be used to the advantage of islands wishing to make their electricity system transition in a staged process. Developing the electricity system in such a way - by for example adding 10 or 20% renewable penetration each year - would delay the need for storage for multiple years, allowing for significant cost reductions for batteries, and other storage options like H_2 Storage for example, to take place. The Sensitivity Analysis highlighted that a reduction in the Investment Cost of the batteries of between 50 and 70% already caused battery storage to become more favourable than PHS, and with battery costs expected to fall by 47% in the coming 5 years [45], larger-scale battery storage may well become feasible for such an approach.

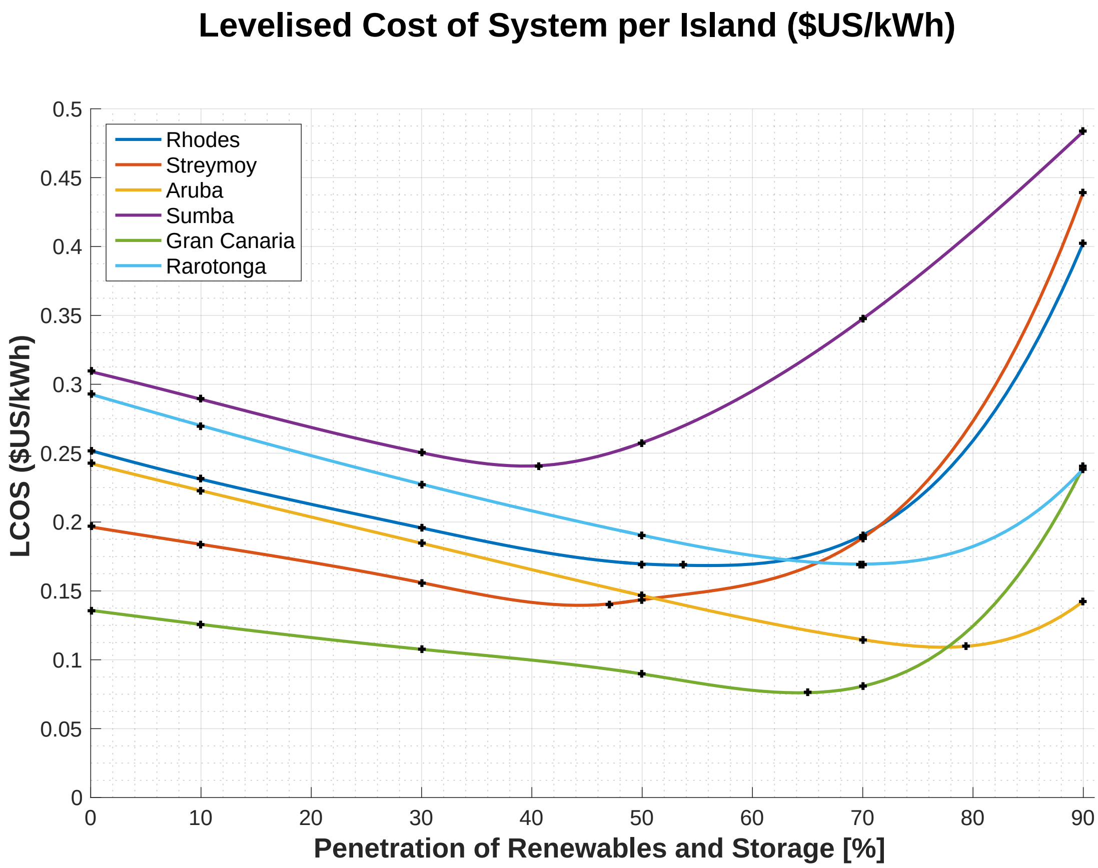


Figure 9-1: Levelised Cost of System (LCOS) with increased RES penetration

9-2 System Configurations, Dumped Energy, and Installed Capacities of Optimal Systems

A general trend can be observed in the system configurations and the amount of dumped energy for the cost-optimal systems. The installed capacities of renewables range from 50% in Gran Canaria up to 80% in Rarotonga and Aruba. Also of interest, is the fact that none of the cost-optimal systems include any storage. As for the amount of dump, it emerges that all of the optimal systems require a moderate level of dump, varying in the range of 10% in Sumba and Gran Canaria up to 37% in Aruba.

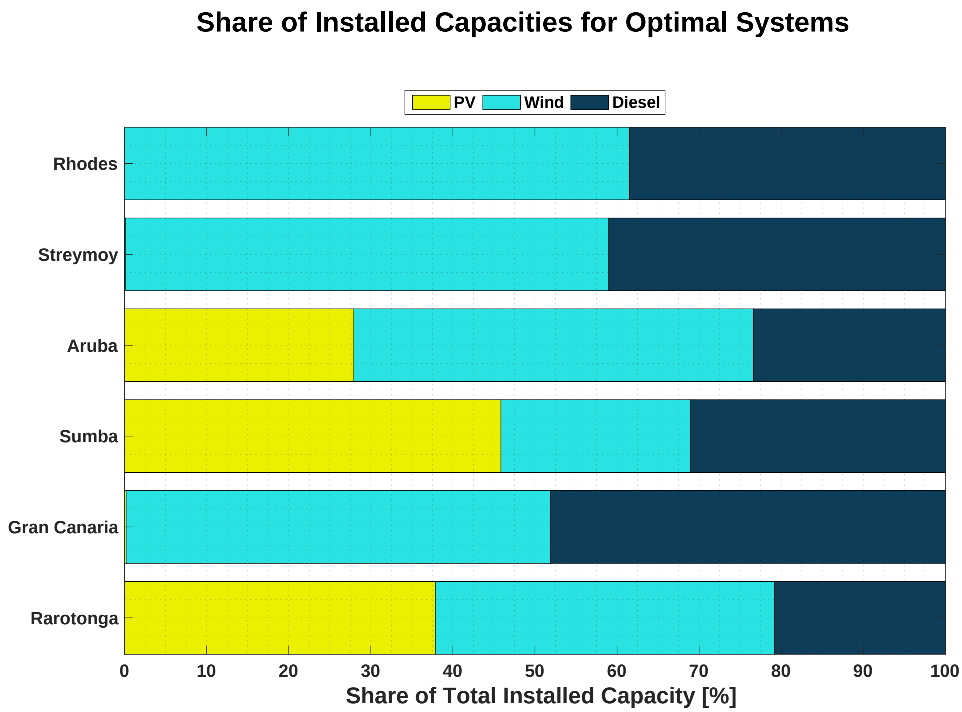


Figure 9-2: Optimal System Configuration by % of Total Installed Capacity

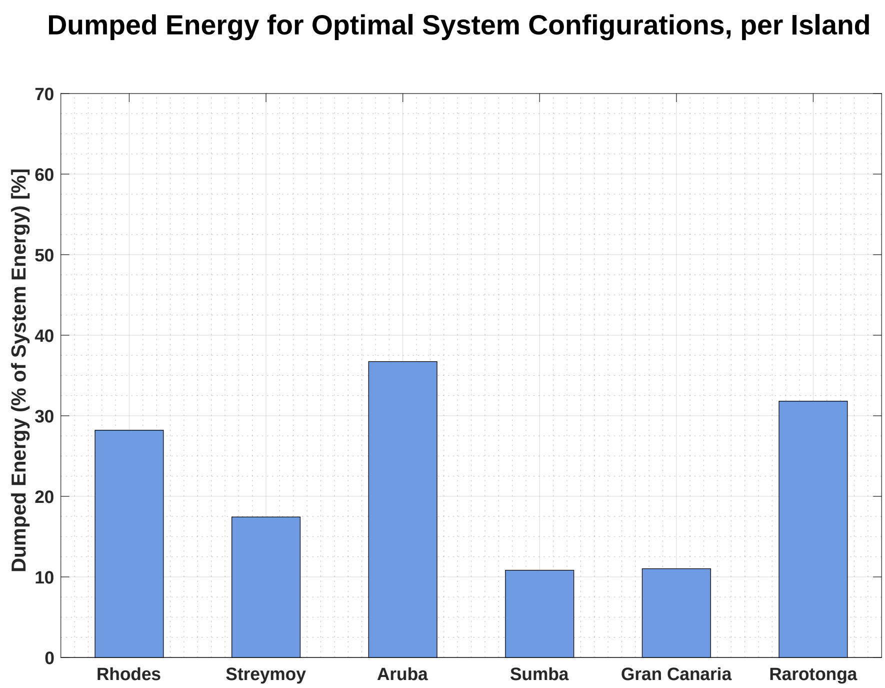
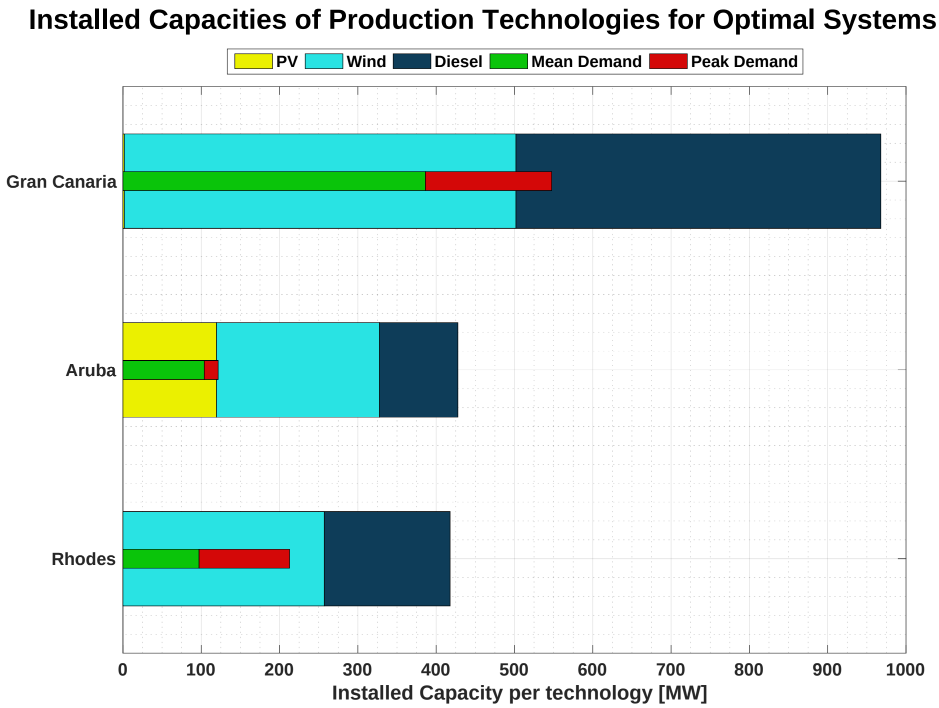
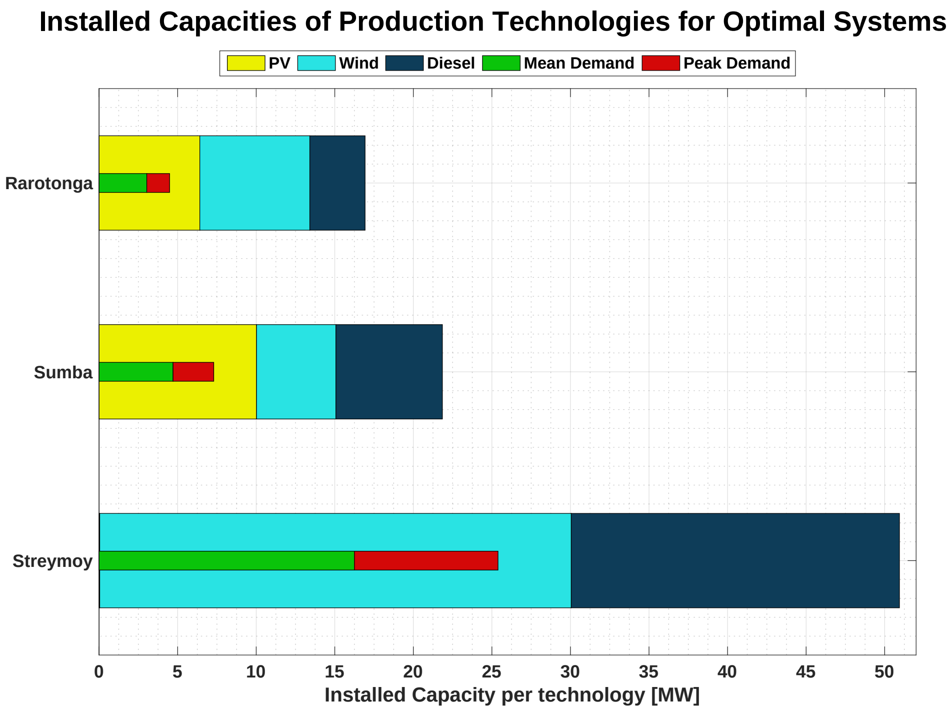


Figure 9-3: Dumped Energy for Optimal System Configurations



(a) 'Large' Islands: Rhodes, Aruba & Gran Canaria

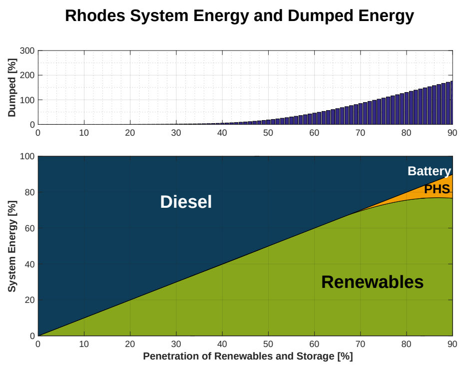


(b) 'Small' Islands: Streymoy, Sumba & Rarotonga

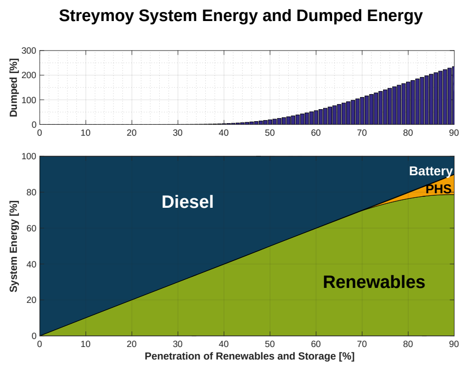
Figure 9-4: Installed Capacity of Optimal System Production Technologies

9-3 Share of Renewables, Diesel, Storage and Excess Production

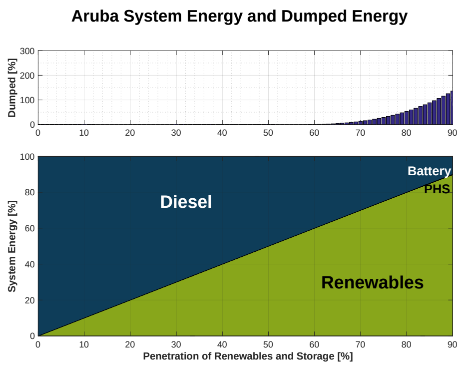
Illustrated in Figure 9-5 below, is the variation of the shares of renewables and storage with increased RES penetrations, for the 6 islands investigated. As can be seen, Sumba stands out as the only island with a significant contribution from the PHS, and a curbing of its dumped energy at high penetration. The primary reason for this appears to be 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 can be seen later in Figure 9-9. Other possible underlying reasons, and an analysis of these results are explored in the **Discussion**.



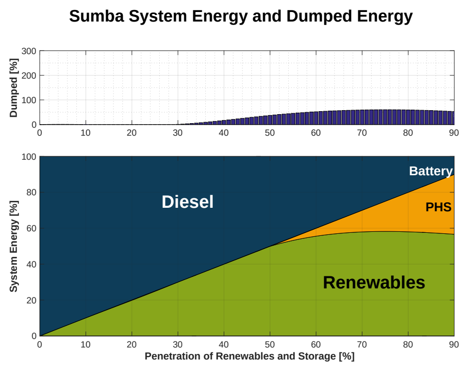
(a) Rhodes



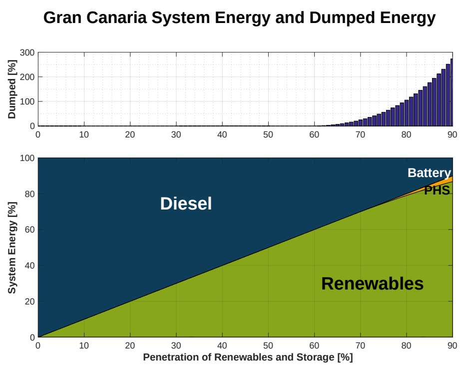
(b) Streymoy



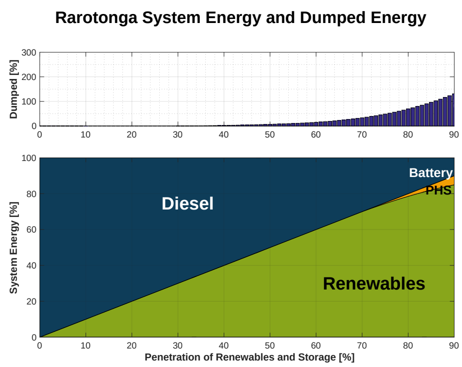
(c) Aruba



(d) Sumba



(e) Gran Canaria

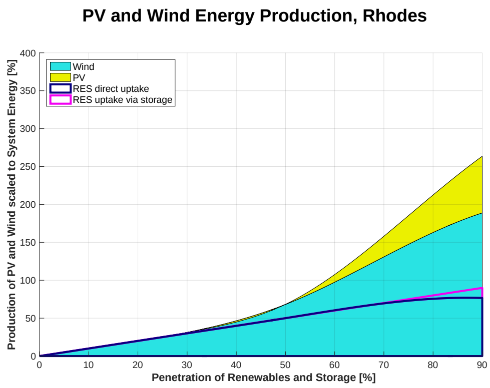


(f) Rarotonga

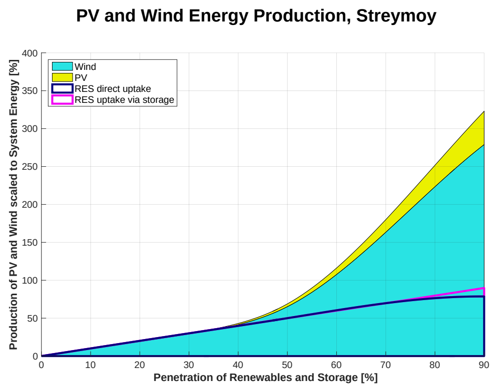
Figure 9-5: System Energy Produced and Energy Required to be Curtailed

9-4 Production Share of PV and Wind Energy

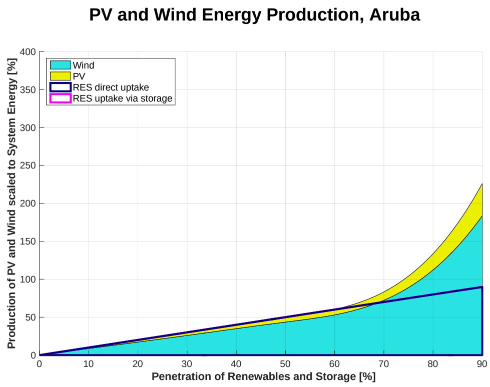
Shown below in 9-6 is the amount of PV and wind energy produced as a function of RES penetration, with the portion of renewable energy meeting the demand directly - and indirectly via storage - indicated also.



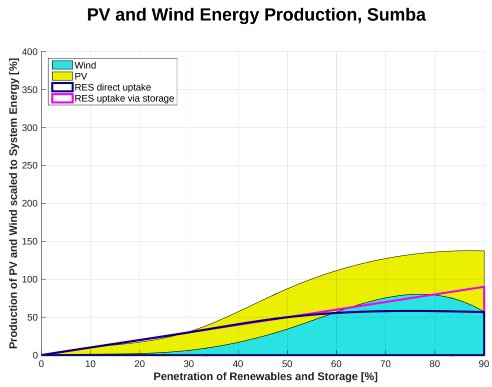
(a) Rhodes



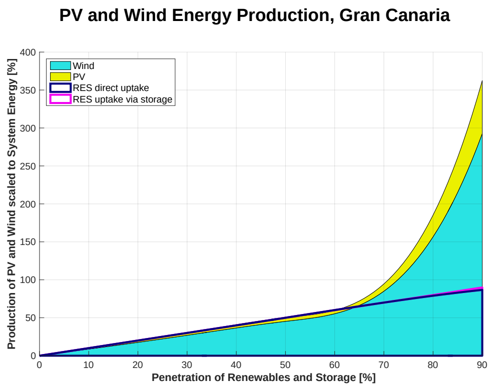
(b) Streymoy



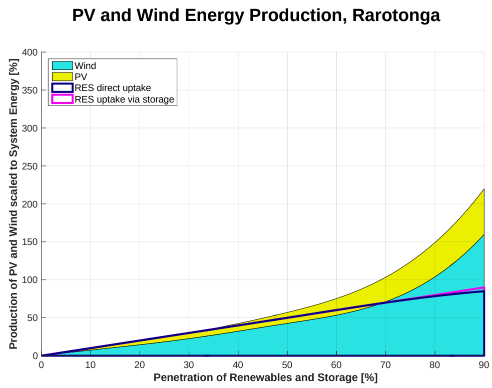
(c) Aruba



(d) Sumba



(e) Gran Canaria

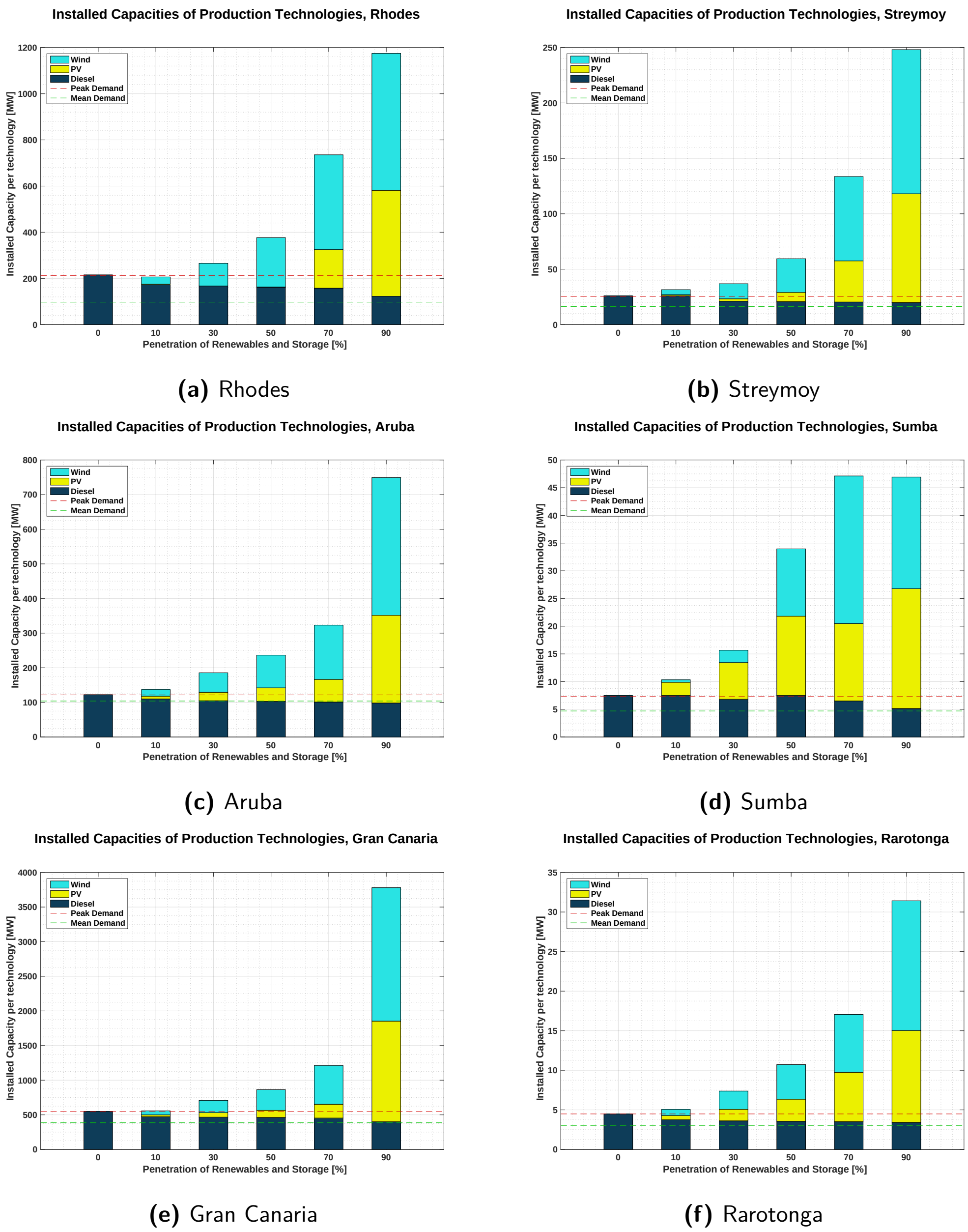


(f) Rarotonga

Figure 9-6: Production of PV and Wind Energy, Direct Uptake by demand, and Indirect Uptake via Storage

9-5 Installed Capacities with Increased Penetration of Renewables & Storage

9-5-1 Production



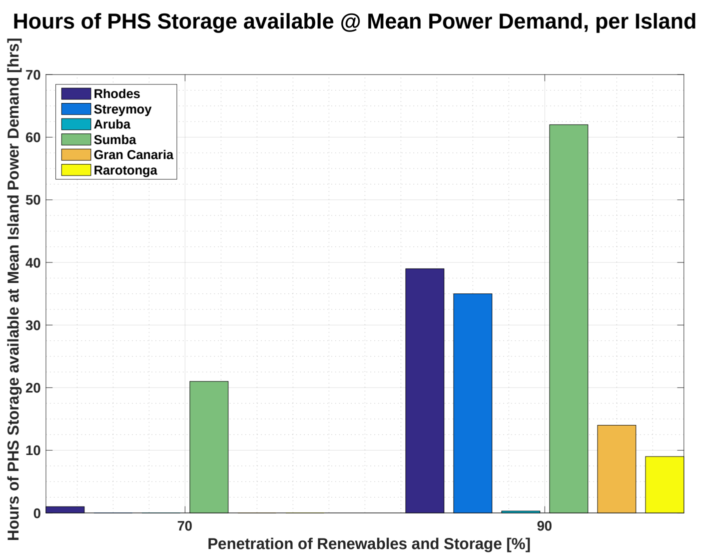
(a) Rhodes **(b)** Streymoy **(c)** Aruba **(d)** Sumba **(e)** Gran Canaria **(f)** Rarotonga

Figure 9-7: Installed Capacities of Production Technologies

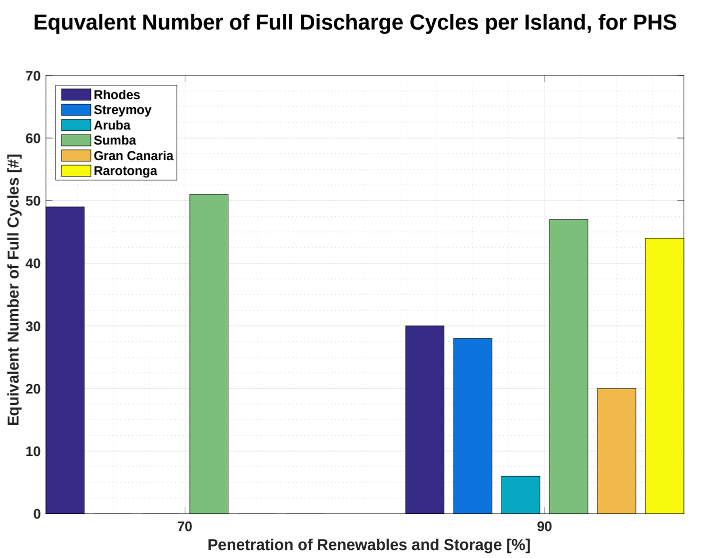
Shown in Figure 9-7, are the installed capacities of PV, wind and diesel with increasing penetrations of renewables, as well as the average and peak electricity demands for the 6 islands. As can be seen, the installed capacities largely exceed the average and peak demands, due to the variable nature of the PV and wind generation. The capacity for the renewables to meet the electricity demands, and the need for generation reserves are addressed later in the **Discussion**.

9-5-2 Storage

Seen below in Figure 9-8a and Figure 9-8b are the number of hours of pumped hydro storage at mean power demand (an indication of the reservoir capacities) and the number of equivalent full discharge cycles made, per island. The product of the two gives the total energy provided by the PHS, previously illustrated in Figure 9-5.



(a) Hours of Pumped Hydro Storage at Mean Demand, at 70% and 90% RES penetration



(b) Number of Equivalent Full Discharge Cycles for PHS at 70% and 90% RES penetration

9-6 Periods with no PV and Wind Production

As previously mentioned, the simulated electricity system of Sumba experiences the highest number of hours with no production from both PV and wind. Conversely, Aruba - with the lowest number of hours - requires almost no storage at all even at a RES penetration level of 90%.

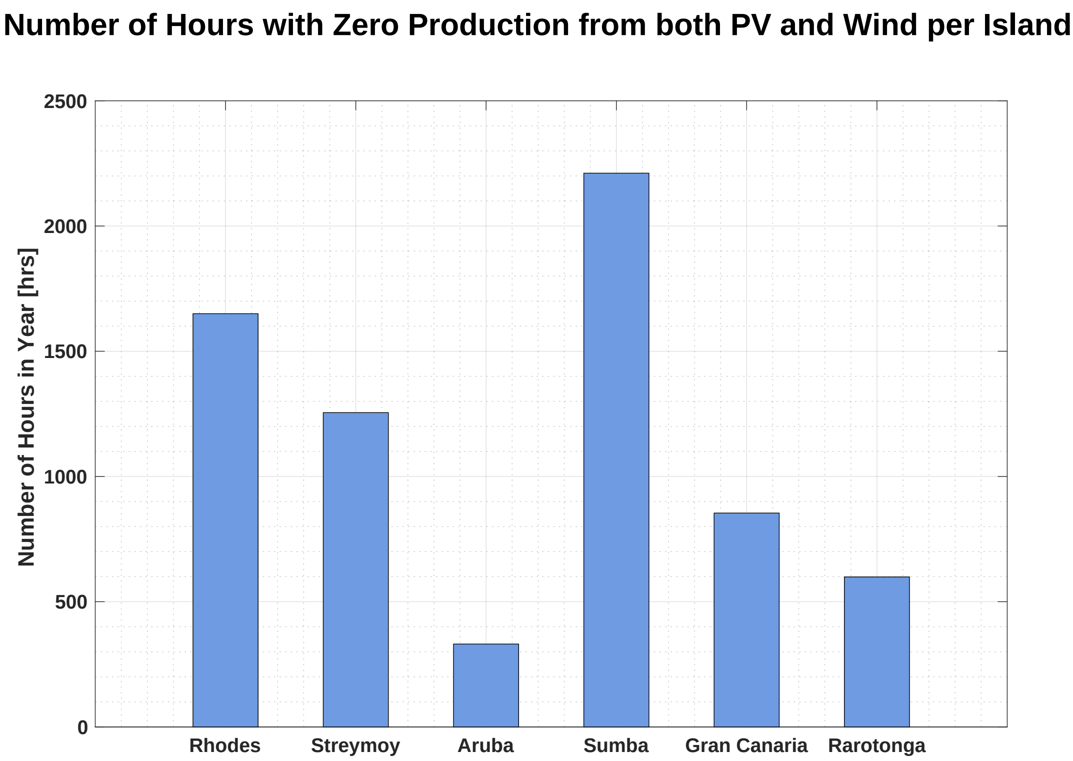


Figure 9-9: Hours with No Production from both PV and Wind

9-7 Area Required for PV and Wind Production

In order to ascertain a general indication of the land area required for the PV and wind production, a calculation was made based on the installed capacities of both technologies, the results of which are shown in the graph below. For PV, it was assumed that 150W panels with an area of $1m^2$ [90] were used. Thus the installed capacity was divided by the installed capacity per square meter in order to determine the total number of square metres required. For the wind production, a permanent direct impact area of 0.3 hectares per installed MW ($3000m^2/MW$) was assumed, taken from a study conducted by NREL on the land-use requirements of modern wind power plants [91].

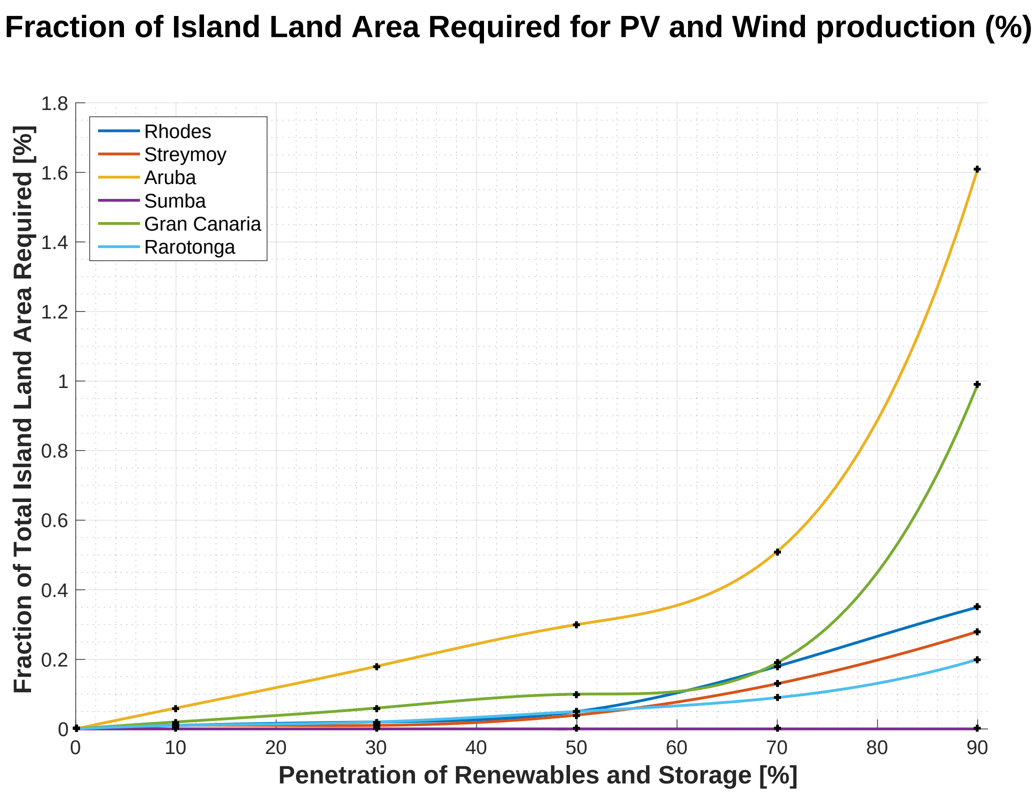


Figure 9-10: Area Required for PV and Wind Production

9-8 LCOE produced per Technology

In order to gain insight into the optimisation results, the LCOE was calculated for each individual technology based on the energy *produced* by each. For the storage technologies, this is the total energy discharged.

Shown in Table 9-1 below, is the minimum LCOE per technology that was found through the optimisations at the 6 penetration levels that were run for each of the 6 islands. It is important here to note that for PV and wind, the below stated cost does not take into account the fact that much of this energy is curtailed, which increases the *real* levelised costs. This is taken into consideration however in the LCOS formulation used for the optimisation.

The levelised costs of PV and wind production were naturally constant across the various penetrations when only considering the energy produced. For the storage however, the most cost-efficient production is logically seen at the 70% and 90% penetrations when the storage starts to significantly penetrate into the system. The number of full discharge cycles ranged from 6-50 for the PHS and 45-120 for the battery in these results.

Island	PV	Wind	PHS	Battery	Diesel
Rhodes	0.102	0.058	0.959	1.628	0.247
Streymoy	0.223	0.051	1.497	1.258	0.194
Aruba	0.093	0.037	1.012	1.065	0.241
Sumba	0.093	0.134	0.821	1.386	0.306
Gran Canaria	0.087	0.030	2.117	2.141	0.133
Rarotonga	0.103	0.060	0.949	0.812	0.290

Table 9-1: Minimum Levelised Cost of Energy (LCOE) Produced in [$US/kWh]

9-9 Influence of System Size on Configuration

The influence of system size was tested by optimising the Rhodes electricity system at 70% RES penetration for different mean power demands. As seen in Figure 9-11 below, the effect of this variation was quite negligible, and effectively scaled linearly. The reasons associated with this, particularly the fact that non-linear cost scaling wasn't included, are discussed further in the **Discussion**.

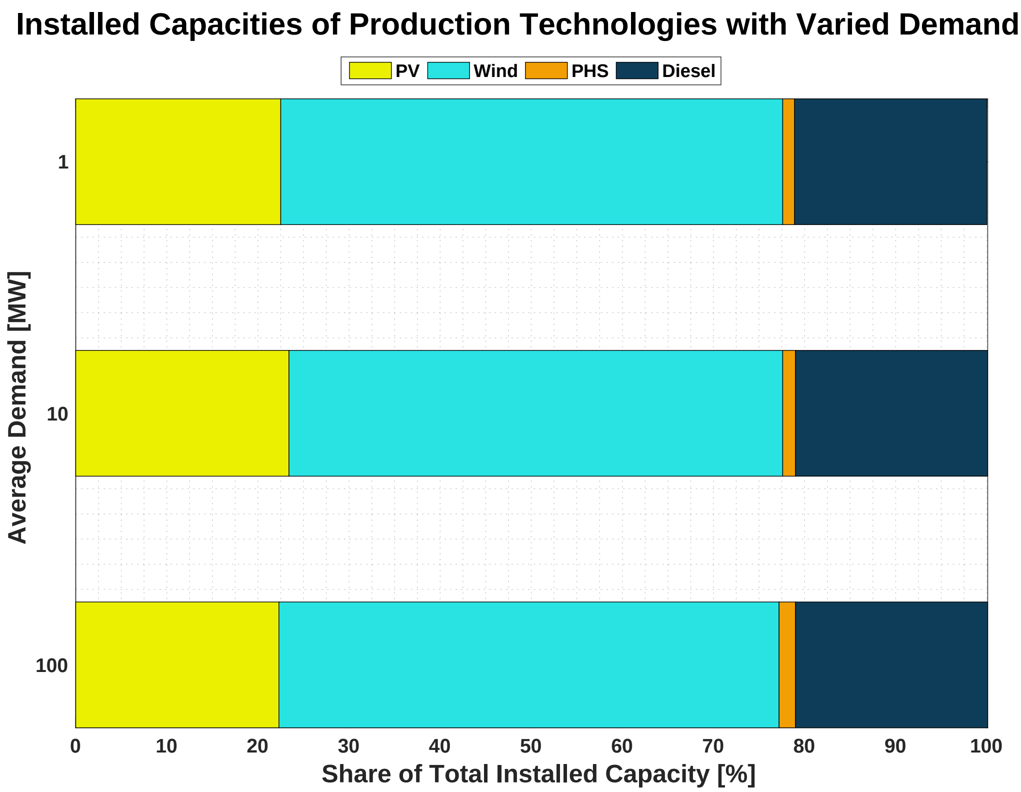


Figure 9-11: System Configuration with Varied Demand

9-10 Sensitivity Analysis

In order to gauge the influence of certain inputs to the model, a sensitivity analysis was carried out by varying specific parameters of interest, and comparing them to a standard base case. The Optimal System of Rhodes with a Renewables and Storage Penetration of 70% (Diesel 30%) was selected as the reference case. Table 9-2 below summarises the effects of the various parameters tested on the Levelised Cost of System (LCOS), followed by some of the interesting effects observed on the optimal system configurations.

Parameter	Degree of variation	LCOS ($US/kWh)	% Difference
Base Case (70% RES penetration)	-	0.1904	-
Geothermal (% of mean demand)	25%	0.1491	-21.7
	50%	0.1373	-27.9
PHS reservoir price (Ires)	-50%	0.1884	-1.0
PV Price (Ipv)	-50%	0.1749	-8.1
	+50%	0.2010	5.6
Battery Price (Ibat)	-90%	0.1862	-2.2
	-70%	0.1889	-0.8
	-50%	0.1899	-0.3
	+50%	0.1899	-0.3
Discount rate (r)	1%	0.1605	-15.7
	3%	0.1747	-8.2
	5%	0.1904	-
	7%	0.2074	9.0
	9%	0.2257	18.5

Table 9-2: Sensitivity of LCOS to Selected Parameters

9-10-1 Geothermal Energy Inclusion

Shown below is the effect on the optimal system configurations with geothermal energy inclusion. Constant Geothermal electricity production at 25% and 50% of mean demand showed significant reductions in the required installation capacities of PV and wind and the amount of dumped energy (as well as the LCOS), demonstrating the value that geothermal energy can provide.

9-10-2 PHS Reservoir Investment Cost Reduction

It was first thought that the reason for over-producing and curtailing rather than utilising storage from RES penetrations of 30-60% could be that the assumption made in the division of power generation equipment and reservoir costs was too heavily weighted on the reservoir

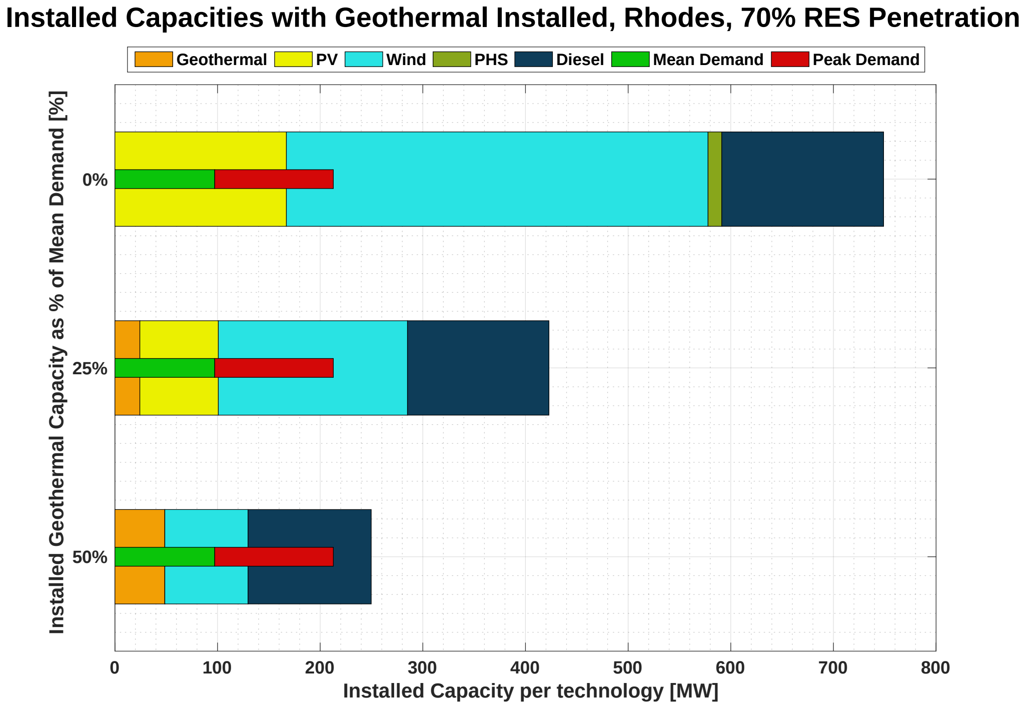


Figure 9-12: System Configuration with Geothermal Energy Inclusion

costs. To check this, the Investment Cost of the reservoir was decreased by 50% and the optimisation run again. The effect on the installed capacity of the PHS reservoir was quite modest, with a 6% increase in the installed capacity of both the upper and lower reservoirs, and a LCOS reduction of 1%.

9-10-3 Battery Investment Cost Reductions

It can be inferred from Figure 9-13 below that a reduction in the battery investment costs of between 50% and 70% sees battery storage become a more favourable storage than PHS. A large amount of battery storage can also be seen to be installed when costs are reduced by 90%, reducing the required capacity of wind installed.

9-10-4 PV Investment Cost Variation

As could be logically predicted, the effect of increasing and decreasing the PV investment costs resulted in reduced and increased PV installed capacities respectively. A cost increase of 50% saw the installed capacity decrease by 32%, while a cost decrease of 50% saw installed capacity rise increase by 46%.

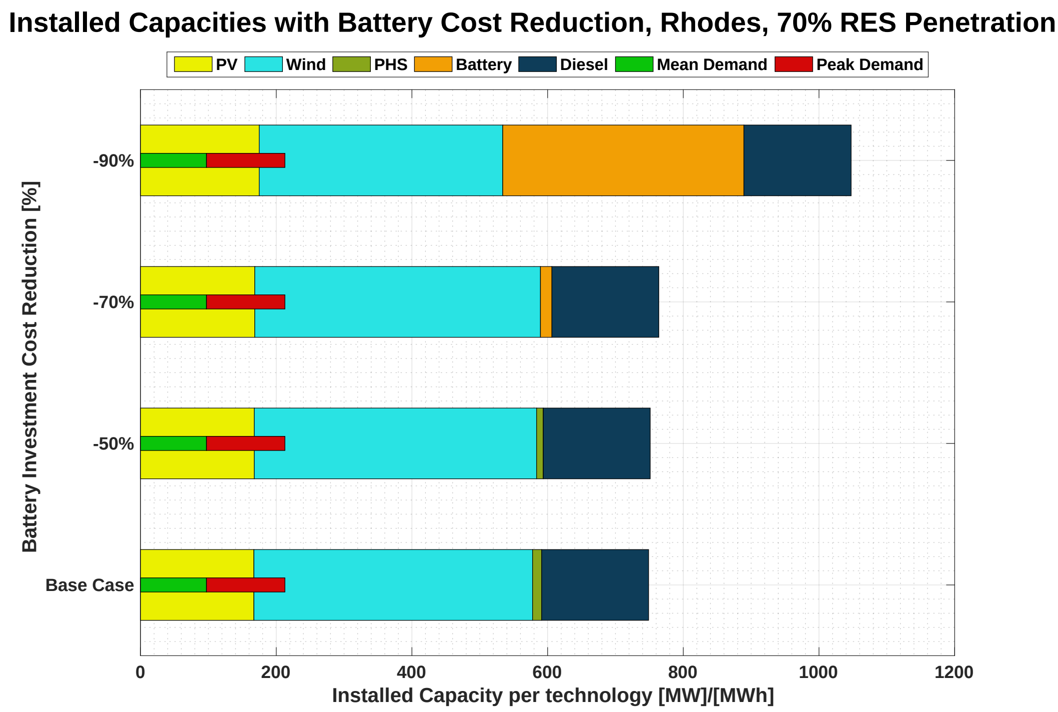


Figure 9-13: System Configuration with Battery Investment Cost Reductions

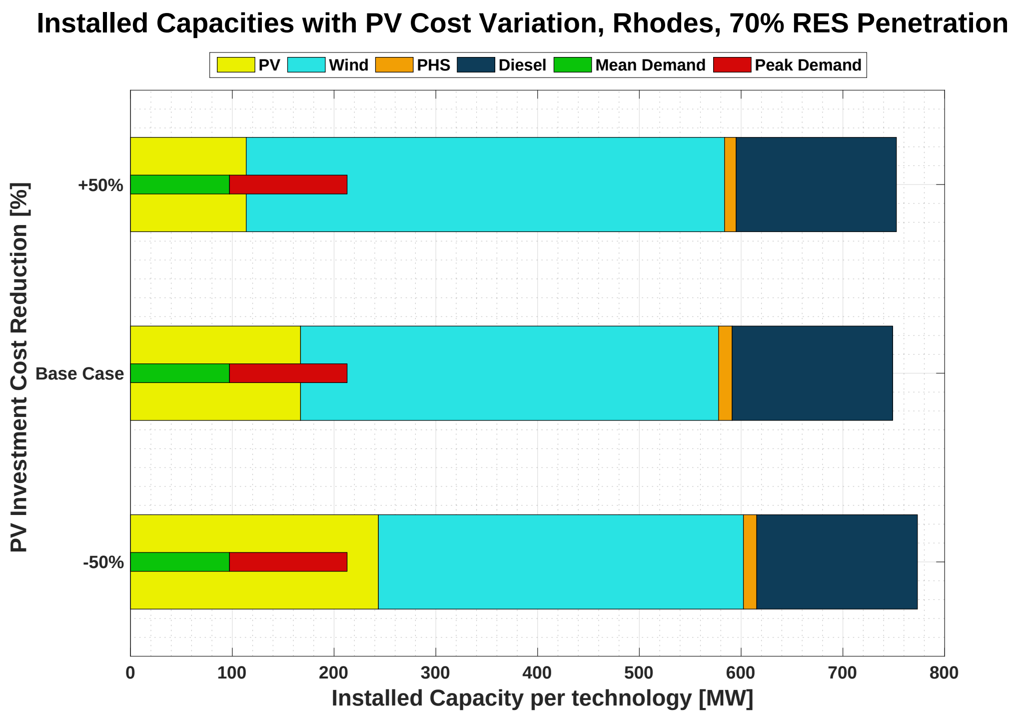


Figure 9-14: System Configuration with PV Investment Cost Variation

9-10-5 Discount rate (r)

The effect of varying the discount rate was only investigated for its impact on the LCOS, and optimisations were not run to determine if the system configuration changes, due to time limitations. It would be of interest to investigate this in future work. The effect of the discount rate showed, logically, that decreasing the discount rate to 3% and 1% showed LCOS decreases of 8% and 15% respectively. Increasing the discount rate to 7% and 9% showed LCOS increases of 9% and 18%.

Chapter 10

Discussion

10-1 Analysis of Results

Additional Costs

An important consideration in this discussion are the additional costs associated with the production and actual integration of the produced renewable electricity into the island grids. As mentioned in the Optimisation, costs associated with grid reinforcement and power quality management due to the increased penetration of the more variable renewable sources are not included in the LCOS, and these costs could shift the optimistic results obtained to more modest renewable penetration levels. Additionally, it is likely that the installation of renewables 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, however for the PV and wind production, standard values were taken.

Over-production & Curtailment

Another important factor to consider is the large over-production of renewable energy present in each of the island systems examined. In the optimisation, 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 optimisation process, it is evident that in order to meet the electricity system demand while limiting the diesel output, the optimisation algorithm needs to find the cheapest way of meeting that demand given the constraints applied. As can be seen from Figure 9-6 and Table 9-1, wind energy is favoured 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 levelised cost for PV on Streymoy is likely a combination of the fact it has the lowest average irradiance 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, is 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 [47]. However, it is generally stated that round-trip efficiencies for PHS systems are usually more in the order of 70-80%, so it is likely that the efficiencies selected are a little conservative, increasing the levelised cost of the PHS.

The fact that over-production and curtailment emerges as the favourable 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 (investigated by Sjoerd Moorman as a part of the 'Island Thesis Group'), or even hydrogen production as a means of storage coupled with fuel cells, or as a fuel for transportation.

Entrance of PV

In the cases where wind energy is cheapest, it can be seen that a critical point is reached somewhere between 30 and 70% of renewable energy penetration, where the contribution of PV energy becomes significant. An explanation for this, is 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, other sources must be used to complement the wind energy and meet demand, and it consequently becomes effective to produce with PV (albeit at a higher cost than that of wind energy), because there is a stronger correlation between the demand and PV production pattern, meaning that more of the PV energy is directly utilised, rather than opting for the relatively more expensive storage options.

Effect of System Size

Another interesting result was found, where it was determined that varying the scale of demand made no significant difference to the optimal system configuration. This can be seen in shown in Figure 9-11 where all of the configurations closely resemble one-another. It should be noted however, that this comparison was made only for the case of the Island of Rhodes, with 70% penetration of renewables and storage, and perhaps at higher penetrations the composition of storage technologies and potentially renewable production technologies could vary. Furthermore, economies of scale in terms of the costs relative to the island sizes were not incorporated in the model, another explanation for the limited variation with system size.

The Storage Situation

A general trend was observed during the optimisation where battery storage appeared favourable 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 utilising a combination of battery and PHS systems in considerable magnitudes was unfavourable. The possible reasons for this are manifold. As previously mentioned, the high comparative costs of storage opposed to renewable generation render it less feasible. Secondly, as the permitted diesel energy production was limited with increasing renewable energy penetration, and with the constraint in place that demand must be met to within 0.1% of the total demand energy, it is reasonable that the diesel generation, being unlimited 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 production is easily, quickly reached, necessitating that the storage be able to meet the lower magnitude residual demands of the system. As such, and since PHS was usually found to produce at lower cost than battery storage, it makes sense that a large PHS system would be installed, restricting the possibility for a significantly sized battery system to also be incorporated, as the levelised cost of the battery system would naturally suffer from the larger PHS system, capable of meeting higher power and energy demands. This is also a manifestation of the fact that 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. Additionally, a decision was required to be made in the control system to establish the order in which the storage technologies supply power. Due to the knowledge that PHS power is usually cheaper, and to prolong the life of the battery, the PHS system was prioritised to supply power ahead of the battery. The implication of this, is that the PHS will naturally provide more energy to the system even when the battery is able to, thus decreasing the economic viability of installing a significant battery capacity.

As stated in the Modelling section, 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. As shown in Figure 6-9 however, the efficiency is considerably reduced at lower flow rates for the Francis turbine, though this issue could be partially mitigated by including turbines of multiple sizes, such that some turbines can always operate at the higher end of their rated flow rates.

The Curious Case of Sumba

As seen in Figure 9-5 in the results, Sumba emerges as quite an exceptional case, particularly in relation to the point in renewable penetration at which the PHS enters, but also in terms of the magnitude of its contribution. At a penetration of 50% of renewables, the PHS already begins growing in its contribution to meeting the system energy, where this occurs for the other islands only as early as 70% and often even later. Furthermore, at 90% penetration the PHS provides around 30% of the total system energy. This behaviour can almost certainly be 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. As can be seen in Figure 9-9, Sumba has significantly more hours with no production from wind or solar than any of the other islands, resulting in its demand not being able to be met purely by scaling up renewable production, and therefore necessitating storage at lower renewable penetrations. Furthermore, it is possible that the times at which these periods of no production occur, also correlate with peak demand periods, where since the diesel penetration is limited, storage is also forced to meet these requirements.

Other reasons could also possibly contribute include the fact that Sumba is the only case where PV energy is produced more cheaply than wind. The regularity and consistency of the

PV production both on a daily and yearly scale could contribute to the production being more predictable and regular than in the case where the more irregular wind energy dominates, allowing for the storage to charge and discharge in a more consistent fashion. Secondly, Sumba has the second highest head difference for its PHS system out of all the islands, also increasing its cost-effectiveness. Finally, since the yearly demand was synthesised from a single day's demand pattern, it could also exhibit more regularity than that of the other cases, again making the storage more effective in meeting the demand pattern that is always the same.

The Perks of Geothermal

There was limited proof of conducive local conditions for geothermal electricity production on all of the case studies investigated, however the influence of geothermal energy was tested in the sensitivity analysis to get an indication on the degree of its potential impact. A geothermal installation capable of producing at 25% of the mean demand, resulted in a 21.7% reduction in the LCOS. At 50%, this reduction amounted to 27.9%. These limited results seem to give an indication for the great potential of geothermal energy - and potentially other base-load energy sources - to reduce overall electricity production costs. Additionally, although not addressed in this research, is the potential for geothermal energy to be exploited together with common geothermal heat exchangers for cooling production. When coupled with heat pumps, geothermal energy can achieve annual electricity consumption reductions of 30-40% [70], limiting the high electricity peaks of the system that are most commonly met by diesel generation, in turn allowing for higher penetrations of renewable energy.

Land Area Requirements

The decision was made in the Modelling section to use parameters for a 'close roof mount' situation that would be appropriate for rooftop solar installations, based on the assumption that space on these islands is very limited, especially for utility-scale renewable energy facilities. However, as can be seen in Figure 9-10, the required area for the combined PV and wind installations as a percentage of the total land area is quite small, less than 0.2% at a 70% RES penetration, and 0.35% at 90% penetration. Thus, utility-scale production facilities are likely not as infeasible as was first thought. The case of Aruba is an exception, and also Gran Canaria at a penetration of 90% RES penetration, seeing these percentages increase to approximately 1.6% and 1% respectively. This can likely be attributed to the high population densities and subsequent ratio of electricity demand to land area on these islands, which are significantly higher than the other cases. Alternatively, using the parameters for an open-mount situation - allowing for increased air flow over the panel and cooling to take place - would marginally improve the temperature-dependent efficiency of the modules which decreases with increased cell temperature. This would result in slightly reduced installed capacity requirements due to the higher efficiency production.

Diesel Investments

As stated in the Optimisation section, diesel investment costs were included in the LCOS calculations, however most of the islands already have substantial generation capacity. As was stated, the investment costs for the diesel generators are quite minuscule in comparison to the fuel costs. This is clearly evident through an example. In looking at the Rhodes system with a 100% diesel based configuration, the investment costs constituted a mere 5.2% of the LCOS, while the fuel costs made up 87.3% and fixed and variable maintenance making up the remaining 1.5% and 6% respectively.

System Life

In the LCOS calculation for the Optimisation, a system lifetime of 20 years was used for all of the technologies and their associated costs. According to the cost data used [77, 45], a system life of 20 years was appropriate for wind, diesel, batteries (including a replacement cost), and the PHS system. However, the utility-scale PV installation had a specified life of 30 years. This means that the levelised cost of energy for PV (and most likely for the PHS system too, usually with a life in the range of 60-80 years) would be reduced. The inclusion of the specific technology lifetimes was neglected for simplicity purposes, however including them would give a better picture of the real levelised costs of the various technologies, and could potentially see PV more competitive with wind (as seen in Figure 9-14 where a 50% reduction in cost resulted in a greater share of PV installed).

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 Optimisation. As a result, and the fact that the goal is generally to maintain a balanced system meeting demand at all times, either over-sizing the system or adding generation reserves would be recommended. 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 preferred technology.

Bio-based Fuels as an Alternative to Diesel

As islands make the transition to higher penetrations of renewable energy into their electricity grids, bio-based fuels could additionally become of interest for use with traditional diesel generators. This could allow for high residual demand peaks and generation reserves to be addressed in a more sustainable way to diesel. Since significant bio-based fuel production is a challenge on most islands however, the same problems would likely arise as with diesel fuel, in premium prices being seen on islands due to the greater difficulty in logistics. Whether these fuels could then still be competitive with the falling costs of storage for island applications, remains to be seen.

Verification & Validation

The model is built upon quite fundamental and well established equations, with a fairly basic control logic. In order to verify that the production and storage technologies were behaving as they should theoretically, they were extensively tested under the full range of possible scenarios with known values. Furthermore, it was possible to verify the control system was functioning properly by examining the times at which different power flows took place, and their magnitudes.

It was deemed that undertaking a comparative model validation process was not required, however performing the optimisation with a different optimisation routine, and comparing the results with those obtained here would be an interesting follow-up. Additionally, it would be of interest to perform the same optimisations using one of the commercially available software tools such as TRNSYS16, HOMER or H2RES. Although the modelling assumptions and approach will vary in these tools when compared to the various technologies modelled in this project, a comparison of the range of results obtained could be made to validate, and gain further insights and understanding of how and why the system configurations vary.

10-1-1 Uncertainties

Global Optimum

Because of the nature of the fmincon solver - which terminates its search once a local minimum satisfying the optimisation constraints is found - it is not possible to guarantee with certainty that global minimums were found in each of the optimisations 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 optimisation process, depending on how close to the 'known' 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 prioritised 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. This approach increases the level of certainty that a global minimum has been reached, however as mentioned previously, there is no such guarantee. This fact 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.

On top of this, it is also important to mention that although there appears to be a similar, logical pattern in the optimal system configurations obtained, it is highly likely that due to the number of variables, and the level of accuracy for which the optimal LCOS is determined, very 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 and most favourable configuration for their particular system.

Sub-hourly operation

As was earlier stated, running the model with averaged hourly time steps does not cover the occurrences and behaviour of the system within these hourly steps. Issues such as frequency stabilisation are not addressed on the hourly time scale implemented in the model. Occurrences such as the sub-hourly drops of wind speed for example could result in sudden losses of production, requiring alternative generation to meet these shorter term demands. These smaller time scale concerns could require additional generation/storage capacity, like diesel, batteries, or flywheel storage, that are able to maintain the reliable function of the system. These technologies however also come at a price, which would need to be added (as required) to the calculated LCOS in order to see the full picture.

PHS Feasibility

The assumption that PHS is feasible on every island, with an achievable head height (H) 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.

Demand evolution

As mentioned earlier in the report, 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 optimisation over multiple years, or even just incorporating expected future demand developments, could allow for the provision of a system configuration which is cost-optimal over a duration closer to the system lifetime.

Data Correlation

Measured wind speed and temperature data was used in the model, from the Integrated Surface Database (ISD) of the National Oceanic and Atmospheric Administration. Unfortunately, the weather stations present on the six islands investigated do not also measure solar irradiance, and therefore this data was sourced elsewhere. The solar irradiance data was obtained from the Meteonorm database, which produces averaged data over a 10 year period to construct hourly irradiance data for a 'typical year.' A comparison was made between the real wind data and the wind data synthesised by Meteonorm, and it was found that the synthesised data did not adequately reflect the variability of the wind speeds evident in the real data. Consequently, the decision was made to use the real measured data for the wind speeds and temperature, complemented with the solar irradiance data from Meteonorm. Using these two different data sources has the implication that any physical correlation between the wind speeds, temperature and solar irradiance may not be kept intact. This fact could influence the system configurations - particularly in terms of the number of hours with zero production from both PV and wind - however since it is only the irradiance data that was synthesised/averaged, which follows a much more highly predictable pattern than that of the wind speeds, it is likely that the distortion to this correlation, and the consequent impact of this, is quite minimal.

Battery DoD limit effect on lifetime costs

The approach of permitting full charging of the battery and a 90% DoD limit (10% SOC min) is quite liberal, and would generally result in a reduction of the battery's cycle life. The effect of the battery DoD on the lifetime costs of the battery was not investigated in this project, however the results of the Optimisation showed that the maximum number of equivalent full discharge cycles of the battery was quite low, only in the order of 60-120 for the yearly time period simulated. Over the period of the system's specified 20-year lifetime, this would still only amount to a maximum total of 2500 cycles, much less than the 8,000-10,000 cycle limit presented in Figure 6-7. This suggests that perhaps the inclusion of battery replacement costs after 10 years in this case would even be a little bit conservative, as the battery could possibly continue to function beyond this point, although chemical degradation factors purely due to time are also at play.

In the case the battery would be performing larger numbers of cycles, an optimal balance would exist between maximising energy output per cycle - therefore reducing the installed capacity of the battery required to meet a certain demand - and prolonging the life of the battery by limiting the depth of discharge. Determining this optimal balance would be useful in optimising the LCOS over the system's lifetime in this case.

Wind speed conversion to turbine hub height

The conversion of wind speeds measured at a known point to a higher height is commonly performed using the log wind profile law, however this law is subject to some degree of uncertainty in terms of the assumed surface roughness length. A surface roughness length of 0.2m was assumed for converting the measured wind speed data to wind speeds at the hub height of the turbine (78m). This roughness length is appropriate for "agricultural land with many houses, shrubs and plants, or 8 metres tall sheltering hedgerows within a distance of about 250 metres"[57]. This value was assumed before the data was sourced, under the pretence that since islands are usually quite dense and space-restricted, it is likely that most areas in the island would have some kind of moderate obstructions within 250m. In hindsight, the measurements were taken from weather stations that are usually located at airports, where it is likely there are much less obstructions than in the case assumed. It is also most likely that the wind turbines would be sited in locations where there is minimal surface obstructions. The implication of subsequently using a lower surface roughness length would be that the calculated wind speeds at hub height are reduced, which would influence the magnitude of wind power production and hence its capacity factor, making the levelised cost of wind energy more expensive.

Chapter 11

Conclusions

- Islands have a genuine reason to invest in renewable energy technologies for their electricity generation needs. Levelised system costs (LCOS) 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 40-70%, coupled with diesel generation. PV makes a significant contribution on three islands, in the Malay Archipelago, Pacific Ocean, and Caribbean Sea, namely the islands of Sumba (where PV production was cheaper than wind and the primary production method), Rarotonga and Aruba.
- Beyond the 40-80% optimal penetration point, the ability for PV and wind 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 LCOS) given the increasingly limited amount of diesel production permitted. Despite this increase, renewable electricity integration in the order of 60-90+% of total system energy can still be achieved with no added cost from the initial situation of 0% penetration of renewables.
- Varying the scale of demand made no significant difference to the optimal system configuration, however this was only investigated in the case of Rhodes, at a penetration of 70% of renewables. Additionally, scale-dependent costs were not included which could also influence this situation. Further investigation, and the inclusion of such factors would shed more light on this.
- 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 favourable to PHS 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, PHS was favoured to battery storage as renewable energy penetration exceeded 70%.

- The island of Sumba demonstrated the value of storage, in limiting the amount of curtailed renewables to around 50% - relatively quite low compared to the values in excess of 100% seen on the other islands.
- A reduction in the investment cost of batteries of between 50 and 70% caused battery storage to become more favourable than PHS, and with Li-ion battery costs forecast to fall by 47% in the coming 5 years [45], 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 40-80%, opting not to make investment in renewables (primarily wind) for islands would be nonsensical considering the associated cost reductions. Adding 10 or 20% renewable penetration each year in staged process could allow islands some time for battery costs to fall to a price competitive with PHS, and they could then be installed at the later date when approaching higher renewable penetrations towards 100%.
- It is highly likely that due to the number of variables, and the level of accuracy for which the optimal LCOS was determined, very 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 favourable configuration for their particular system.
- Geothermal energy demonstrated its value in significantly reducing overall electricity production costs, re-affirming the worth of investigating it as a serious option for electricity generation on islands that are endowed with high resource potentials.

Chapter 12

Recommendations

1. The strongest recommendation that emerges from this research is the business case for islands to start installing wind energy, effective immediately. With renewable energy penetrations from 10-70% it is a no-regret decision to install more and more wind generation capacity, and this energy is directly absorbed when production is between 30-60% of total system energy. It is only in one case (Sumba) - where it is cheaper to install PV over wind - and at very high penetration, that the installed capacity of wind decreases for an optimal system. Then, in the coming 5 years as costs for Li-ion batteries fall, battery storage could be added to the systems in increasing amounts in order to approach high renewable energy penetrations, towards 100%.

2. Given the economically preferable position of wind energy, a recommended next step for the modelling would be to include wind turbines with smaller rated power capacities, which would allow for the maximising the utilisation of the wind resource at lower wind speeds also. It would be of interest to see whether the share of wind energy for the cost-optimal configurations increases as a result of this inclusion.

3. One of the shortcomings of this research is that it does not address the physical, continuous and reliable performance of the electricity supply system on a minute and second scale. Modelling the optimal systems determined in this research in more detail, with smaller time steps and by including the required electrical components and grid infrastructure (either in Simulink or a more specified power system analysis software) would provide more certainty on the feasibility of these systems in reality, and give a clearer picture on the potential infrastructure reinforcements and generation reserves required.

4. The high costs of storage when compared to generation from PV and wind resulted in the optimisation routine prioritising higher installed capacities of PV and wind over storage, and consequently increasing the amount of dumped energy. In reality, the curtailment of such large amounts of power is not highly preferable. As mentioned, this energy could be utilised for other, flexible applications such as water desalination or electric vehicle charging. Alternatively, to discourage the excessive amounts of curtailed energy

and perhaps further prioritise storage, a price on curtailed energy could be incorporated into the model, or the amount of dumped power permitted could be restricted.

5. As mentioned in the Discussion, it is highly likely that quite different configurations exist at almost identical, but marginally higher LCOS's. As such, determining the configurations and cost differences of these systems - perhaps via different Optimisation techniques - could allow for decision-makers to have complete information on their options, and select a configuration taking into consideration factors other than purely the absolute minimal cost.

6. Finally, as discovered in the Literature Review, an opening remains for research to be done on the implementation process in striving towards the optimal system configurations. Investigation into the policy and investment mechanisms, and the development of a specific transition roadmaps for islands would be of additional service to islands, in their pursuit of sustainable energy systems.

Appendix

Appendix A

Resource Data

A-1 Solar Irradiance and Wind Speed: Monthly Averaged Data

A-1-1 Yearly Solar Irradiance Resource

	Streymoy	**Aruba**	**Sumba**	**Rhodes**	**Gran Canaria**	**Rarotonga**
January	144	4776	4656	2064	3504	6048
February	504	5184	4800	2544	4200	5208
March	1416	5736	4920	4128	5184	4896
April	2760	5640	5088	5568	6240	4080
May	4272	5544	5208	6480	6888	3240
June	4296	5424	4896	7296	7320	3264
July	3816	5520	5400	7344	7320	3408
August	2952	5760	5472	6624	6696	3888
September	1752	5544	5952	5352	5496	4560
October	720	4776	6264	3648	4632	5160
November	216	4488	5832	2496	3816	6288
December	72	4200	5424	1776	3312	5376
Year	**1896**	**5208**	**5328**	**4608**	**5400**	**4608**

Table A-1: Solar Irradiation for selected islands in W/m^2/d

A-1-2 Yearly Wind Speed Resource

	Streymoy	Aruba	Sumba	Rhodes	Gran Canaria	Rarotonga
January	8.8	6.2	1.9	3.7	7.3	4.0
February	9.2	6.8	2.5	4.3	8.5	3.2
March	6.6	6.2	2.4	4.6	8.1	3.6
April	7.6	6.5	2.6	3.5	7.4	3.8
May	7.1	6.0	2.7	4.3	9.2	3.9
June	5.3	6.9	2.5	4.6	8.5	3.9
July	4.5	7.6	3.5	5.6	11.9	4.0
August	4.4	6.2	3.2	5.4	9.3	3.9
September	5.5	5.4	3.3	4.8	5.8	3.5
October	6.2	4.7	3.2	3.7	3.9	3.7
November	7.9	4.2	2.7	2.4	5.4	3.7
December	7.8	5.7	2.3	3.2	3.4	4.2
Year	**6.7**	**6.0**	**2.7**	**4.2**	**7.4**	**3.8**

Table A-2: Average Wind Speeds for selected islands

Appendix B

Storage Cost Data

Technology	Investment Cost		Fixed Maintenance Cost ($US/kWh)	Variable Maintenance Cost ($US/kWh)	Reference
PHS	2312.5	$/kW	6.5		[78]
PHS	301.5	$/kWh	6.5	0	[45]
Battery	1054	$US/kWh	11.5	0	[45]
Battery replacement costs (DC)	922.5	$US/kWh	0	0	[45]
Battery replacement costs (AC)	104.5	$US/kWh	0	0	[45]
Battery(Li)	27.0	$US/kWh	0	0	[45]

Table B-1: Storage Cost Details

In order for the PHS reservoir and power generation equipment to be sized separately via the Optimisation, the costs of these also had to be divided. This was achieved by determining the proportion of the total project costs that were dedicated to the power generation equipment, and assuming the rest was allocated to the reservoir construction, pumping equipment and other associated civil works. Electro-mechanical equipment constitutes on average 16% of the Investment costs for large-scale hydro power projects [92]. Hence, the values of 370$US/kW and 253$US/kWh used in the Optimisation were calculated by 16% * 2312.5 for the power generation and 84% * 301.5 for the construction,pumping and civil works respectively.

It is also worthwhile here to note that reservoir construction costs per cubic metre of capacity were unable to be sourced, and as a result the investment costs for civil works etc. were priced per kilowatt-hour of installed capacity. In converting the reservoir capacities in cubic metres to kilowatt-hours of potential energy, naturally the head height is required to be known. In the case of this project, it was assumed that the associated costs scale proportionately to the head height. This is a reasonable assumption when considering the piping, tunnel excavation, and other civil works that are influenced by head height.

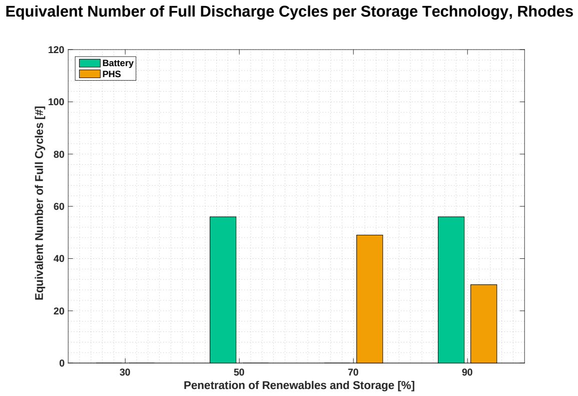
The total investment costs for reservoir construction, pumps, and other civil works were calculated by converting the capacities of the upper and lower reservoirs to the total amount of kilowatt-hours able to be produced, and stored, according to the following formula:

$$Energy \quad Capacity \quad [J] \quad = \quad (IC_{upper} \quad + \quad IC_{lower}) \quad \cdot \quad \rho_w \quad \cdot \quad g \quad \cdot \quad H \tag{B-1}$$

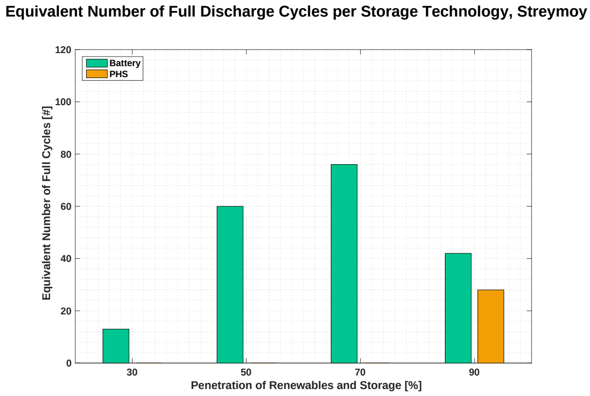
Then, to convert from J to kWh, a factor of 1e-3*1/3600 was applied, and this was multiplied with the $US 1054/kWh cost stated in the table above, to determine the total investment costs for reservoir construction, associated civil works and pumping/other equipment.

Appendix C

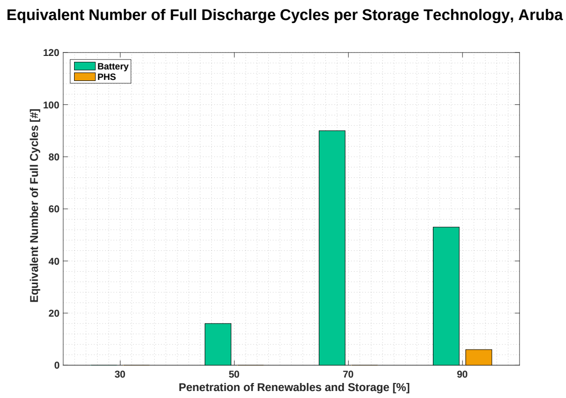
Equivalent Number of Full Discharge Cycles for Storage Technologies



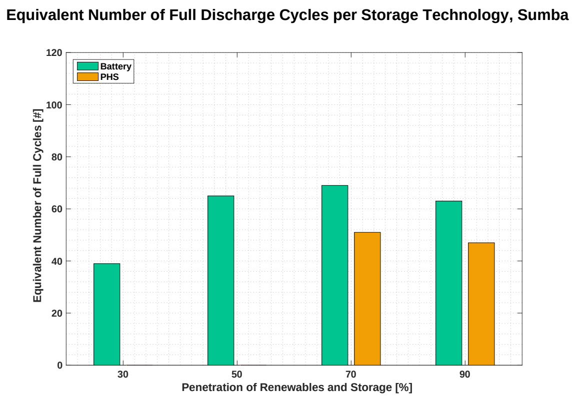
(a) Rhodes



(b) Streymoy

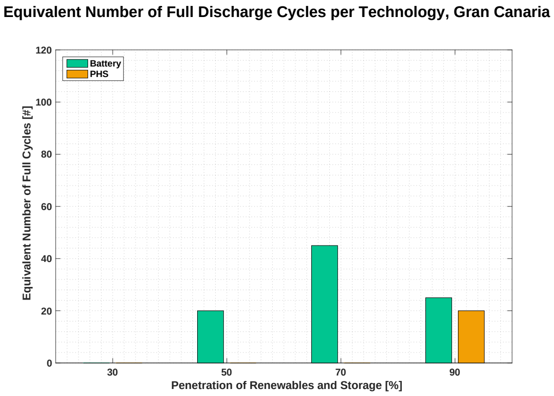


(c) Aruba

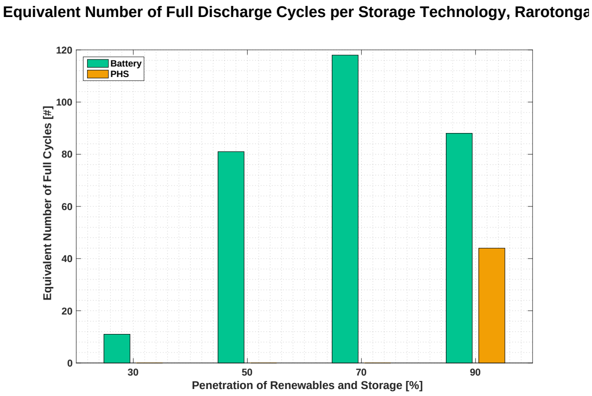


(d) Sumba

Figure C-1: Equivalent Number of Full Discharge Cycles per Storage Technology for Islands



(a) Gran Canaria



(b) Rarotonga

Figure C-2: Equivalent Number of Full Discharge Cycles per Storage Technology for Islands

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Glossary

List of Acronyms

AEA	-	The Aegean Energy Agency
AI	-	Artificial Intelligence
ANN	-	Artificial Neural Networks
BIPV	-	Building Integrated PV
COE	-	Cost of Energy
CPV	-	Concentrator Photovoltaic
CSP	-	Concentrated Solar Power
DAFNI	-	The Network of Sustainable Aegean and Ionian Islands
DoD	-	Depth of Discharge
EA	-	Evolutionary Algorithm
EGS	-	Enhanced Geothermal Systems
ESOI	-	Energy Stored On energy Invested
ETI	-	Energy Transition Initiative
FL	-	Fuzzy Logic
GA	-	Generic Algorithm
H	-	Head Height for PHS
HDR	-	Hot Dry Rock
HFO	-	Heavy Fuel Oil
HRES	-	Hybrid Renewable Energy Systems
IC	-	Installed Capacity
IRENA	-	International Renewable Energy Agency
ISD	-	Integrated Surface Database
LCC	-	Life Cycle Cost
LCOE	-	Levelised Cost of Energy
LCOS	-	Levelised Cost of System
LOLP	-	Loss of Load Probability
LOPP	-	Loss of Power Probability
LP	-	Linear Programming
LPSP	-	Loss of Power Supply probability

MOEA	-	Multi-Objective Evolutionary Algorithm
NOAA	-	National Oceanic and Atmospheric Administration
NPC	-	Net Present Cost
NPV	-	Net Present Value
NREL	-	The National Renewable Energy Laboratory
PAES	-	Pareto archived evolution strategy
PHS	-	Pumped hydro storage
PICTs	-	Pacific Island Countries and Territories
PSO	-	Particle Swarm Optimisation
PV	-	Photovoltaic
RES	-	Renewable Energy Sources
SA	-	Simulated Annealing
SET	-	Sustainable Energy Technology
SOC	-	State of Charge
SQP	-	Sequential Quadratic Programming
TS	-	Tabu Search
UL	-	Unmet Load