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Bachelor Thesis

"Standards review of distributed generation and impact analysis of renewable penetration in a remote microgrid. Case study: San Cristobal Island, Galapagos Archipelago."

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A mi tutor, David, por darme la gran oportunidad de trabajar en un proyecto tan interesante.

A mis padres y mi hermano, por estar ahí en todo momento.

RESUMEN

El presente Trabajo de Fin de Grado pretende realizar un estudio de las reglamentaciones de Generación Distribuida y la planificación energética de la Isla San Cristóbal (Galápagos, Ecuador) para abordar tres retos asociados a la Generación Distribuida. Estos retos son el control de la calidad de la energía inyectada por los generadores, su viabilidad económica y su capacidad de almacenaje energético.

Para tratar el primer reto se ha realizado un estudio de las limitaciones técnicas que se imponen a estos generadores a través de 37 Regulaciones. Se han seleccionado los parámetros técnicos a través de los cuales se regula la calidad de la energía y tras su explicación, se ha realizado una comparativa de cómo se tratan estos parámetros en cada regulación. Para el estudio de los otros dos retos, se han realizado simulaciones mediante el software Homer Pro de la implementación de Generación Distribuida en la Isla de San Cristóbal. Estas simulaciones considerarán tres escenarios diferentes, el primero basado en la situación actual de la Isla, el segundo en la posibilidad de abastecimiento por renovables en un 50% y el último considera el completo abastecimiento por renovables. Dado que el software proporciona resultados económicos además de eléctricos, es posible analizar los dos retos a través de éstos.

Por un lado, los resultados de la comparativa regulatoria demuestran que aún no existe un consenso respecto a estos sistemas, lo cual supone un inconveniente para el desarrollo de esta tecnología. Mediante las simulaciones se han obtenido resultados inesperados en relación a la viabilidad económica, puesto que una mayor penetración de renovables crearía un resultado más favorable. Por otro lado, ha quedado demostrado que la tecnología actual de almacenamiento supone un lastre para que escenarios de Generación Distribuida con alta penetración de renovable sean competitivos energética y económicamente.

Palabras clave: Generación Distribuida, Regulación, Standard, Homer Pro, San Cristóbal.

ABSTRACT

This Bachelor Thesis aims to perform a study of the Distributed Generation regulations and an electric planification of San Cristobal Island (Galapagos, Ecuador) to analyze three challenges related with the Distributed Generation. These challenges are power quality of the service provided by the generators, its economic feasibility, and its power storage capacity.

To deal with the first challenge, a study of the technical requirements imposed on the generators through 37 different regulations has been performed. The most relevant technical parameters through which the standards control the energy quality delivered have been selected, and after explaining them, a comparison among the standards has been done. To study the other two challenges, different simulations of the implementation of Distributed Generation in San Cristobal Island have been performed with the software Homer Pro. These simulations consider three different scenarios, the first one is the actual configuration of the island, the second one considers a service of 50% renewable energies, and the last one is a scenario totally supplied by renewables. As the software displays the economic and electric results, it will be possible to address both challenges through it.

The regulation comparison has demonstrated that there is a lack of harmonization among the standards, which can put at risk the development of this technology. The simulations have shown unexpected results in regard of the economic feasibility, as the scenario which considered half of the supply coming from renewables was more competitive than the diesel fueled one. With respect the storage capacity, it has been proven that the current technology is not enough developed, and it is an impediment for the distributed generation to be competitive.

Key words: Distributed Generation, Regulation, Standard, Homer Pro, San Cristóbal.

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1. Introduction and scope

1.1. Introduction

The Electrical Power System can be broken down pinto three different subsystems: generation, transmission, and distribution. According to the traditional scheme, the generation system is responsible for the production of power, composed of large power plants which are centrally controlled. The generated power is generally produced far away from the customers and later delivered through the transmission system. It is finally placed into the distribution system where the power is delivered to the customers on a more local basis. During the last decades the installation of generators in this last section of the grid has started to increase, which is known as Distributed Generation (DG). The installation of generators next to the customers, in contrast to the traditional power plants far from them, is changing the traditional architecture of the Electric Power System. Distributed Generation can play a major role in the future system, as it is considered a response to some of the new drivers of the current Electric Power Sector, as environmental sustainability and security of electrical supply.

1.2. Scope

The scope of this bachelor thesis is to classify the main power quality issues by analyzing the technical requirements that address them, and to perform an electric planification of a distributed generation powered Island.

The fact that the term distributed generation recently arose implies that the connection of this systems to the grid has been addressed in the same manner as the conventional power plants. However, through the steady and increasing trend in its deployment, it has been proven that their presence in the grid poses new challenges and opportunities very different than those of conventional plants. With the objective of solving these challenges, different organizations have developed specific requirements and standards, or are in the process of it. It is in this evolution and deployment context that this paper will intend to define the major issues that should be addressed for proper regulation of DG systems, and study and compare the requirements among regulations, standards and recommendations in order so as to find a common ground.

The second objective of the paper is to perform the electric planification and simulation of San Cristobal Island, located in Galapagos Archipelago. As the island is only powered by DG systems, the intent is to apply the gathered information in the paper by means of developing different electrical scenarios for the supply and comparing the results. Through the results, two challenges associated with the implementation of DG systems will also be analyzed: the economic feasibility and the power reserve and planning.

1.3. Structure

This paper will develop a deductive approach, consisting in three sections: first an overview on distributed generation, second, an analysis of the power related issues that this poses to the current grid, and finally the design and simulation of electric architecture on the island.

To start with, the paper will provide a literature review of Distributed Generation definitions and the different classifications that exists. The next step is the analysis of the current stage of deployment of the technology, and what drives its implementation. To close this section, there is a highlight on the potential benefits and issues associated with Distributed Generation deployment. These exposed issues will be covered in the following point of the paper.

In the second section, the paper will address one of the main issues the DG deployment is facing, the power quality issues. The structure of the section is simple. First, the 37 studied regulations covering Distributed Generation are presented and referenced. After that, the points through which the regulations treat these issues are presented, such as voltage support, flickers or voltage unbalance. Each of these points will later be explained by answering three questions, what the technical problem is, how it is created and what its effects are. Once there is a basic notion in the problem, the analysis on the technical solutions that the standards define to solve the issue is done by means of an exhaustive study of more than 37 regulation. The solutions that each regulation proposes are consolidated in a table so that results can be easily compared and analyzed. Referencing the extracted data in the table, the results are later analyzed and compared. This procedure has been performed for each of the 11 defined technical requirements or solutions.

The next section begins by providing the general context of the archipelago in terms of the electrical system, and then focuses on the studied Island. Among the general information that is considered is the electrical demand, the grid architecture, and the electrical installations across the island. Next, the software is presented as well as the input data used in the simulation. These simulations will consider the period 2015 to 2025, no longer as the demand projection that has been performed starts to accumulate deviation after 2025. The last section is related to the simulations and results, where 3 different scenarios are planned and implemented on the island. After the software has run each of them, the results are explained and finally, a comparison among all of them is performed in terms of pollutant emissions and costs.

Once the main body of the paper has been completed, two sections are left. The first one is an open suggestion for future projects in line with the present one, together with the issues that arose during the project and have limited the development or accuracy of it. Lastly, in section 6, the conclusions are drawn.

2. Distributed Generation

2.1. Definitions

Traditionally, there has been a lack of agreement on what can exactly be considered as Distribution Generation. The issue has been thoroughly reviewed by different authors [1], whereas European Directive 2003/54/EC defines DG as "generation plants connected to the distribution system". However, there are other organizations and institutions incorporating different terms to the definition, all of them still valid:

- The Institute of Electrical and Electronics Engineers Inc. (IEEE) defines the DG as generation of electricity by facilities sufficiently smaller than central plants, usually 10 MW or less, to allow interconnection at nearly any point in the power system [2]
- The US Department of Energy (DOE) [3]defines DG as modular electric generation or storage located near the point of use. The DOE considers distributed power systems to typically range from less than a kilowatt (kW) to tens of megawatts (MW) in size as DG unit.
- The International Energy Agency (IEA) [4] defines DG as generating plant serving a customer onsite or providing support to a distribution network, connected to the grid at distribution-level voltages.

2.2. Types

There are two main ways of classifying DG systems, depending on the technology of the generators and the interconnection with the grid.
According to the technology, Table 1 introduces the most common DG systems [5]. Some important features that must be considered when studying the strengths and weaknesses of each technologies are:

- The modularity of the system, meaning the capability of the system to be decomposed into smaller units, each of them with functional implementation-independent specification.
- Emissions under continuous operation.
- Stability of the power output, as some Generators will produce energy intermittently, while others deliver a steady output.
- Power output Range of the generator, not all the technologies are capable of deliverin the same amount of power.
- Renewable or non-Renewable: This feature also serves as classification, and it will be further considered in the paper. The Renewable DG systems have an essential role in DG System deployment and are defined as Distributed Renewable Energy Systems (DRE).

Technology	GHG Emissions	Available Size	Modularity
Internal Combustion engine	No	> 5kW	No
Industrial Combustion Engine	No	> 1 MW	No
Microturbine	No	1 kW - 1 MW	No
Stirling Engine	No	< 1 kW - 0.1 MW	No
Fuel Cell System	No	1 kW - 5 MW	No
Micro/Small hydroelectric unit	Yes	> 25kW	Yes
Wind Turbine	Yes	< 1 kW - 6 MW	Yes
Photovolatic array	Yes	< 1 kW - 14 MW	Yes
Solar Thermal Unit	Yes	> 5 kW	Yes
Biomass Unit	No	> 10 kW	No
Geothermal Unit	Yes	> 100 kW	No
Ocean Energy Unit	Yes	50 kW - 5 MW	Yes

Table 1: Current DG Technology highlights

The other broad category of DG systems is Grid connected and off-grid [6]. This classifying method depends on how the DG Systems are being utilized:

- Grid-connected DG
  Composed of Generators that serve the loads and are still connected to the centralized grid. These type of DG systems support the demand, supplying only part of the electrical needs. Because of its usage as a support, DRE systems compose the great majority of these category, as there is no need for a steady inflow of electricity, providing a positive impact for the environments. Within the different technologies, the Photovoltaic (PV) systems are the most common systems.
- Off-Grid DG
  Made up by generators that are not connected to the centralized grid. They can include stand-alone generators, energy sources for small low voltage direct current islanded systems and for medium voltage alternate current islanded systems [6]. An islanded system is a system that is not interconnected to a larger grid, this condition will later be analyzed in Section 3.2.9.

In most cases the DG Systems can act under both conditions, grid connected and off-grid.

2.3. Context

DG systems are gaining momentum, mainly as they are the vehicle for Renewable Energy penetration into the grid. For instance, back in 2004, as shown in Figure 1, DG already had an important share in European energy generation.

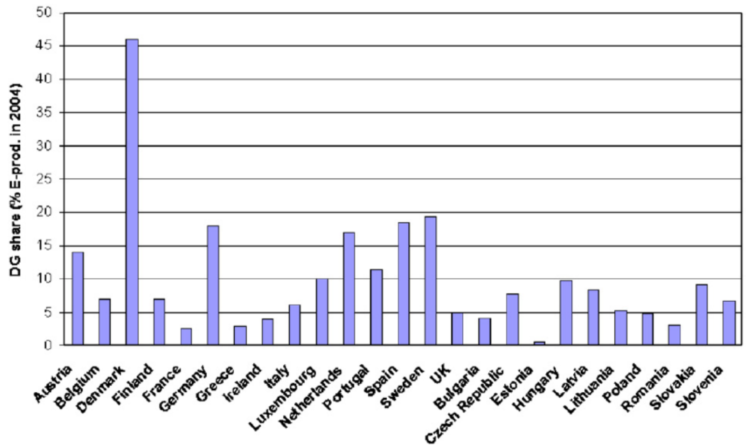


***Figure 1: Share of DG in Europe from 2004** [7]*

But it has been since a global consciousness has grown over climate change and sustainability of the planet, that renewable energy has undergone a boost, and with it, DG systems. Since the signature of the Paris Agreement in 2015 by 196 countries committing to keep the temperature rise in less than 2 Celsius degrees, many countries have prioritized deployment of renewable energy for its achievement.

As proof of the commitment is the European Union, which in a communication the 22nd January 2014 from the Commission to the European Parliament "A policy framework for climate and energy in the period from 2020 to 2030" [8] a target for at least a share of 27% of renewable energy for 2030 and a 40% cut for greenhouse emission was set. Furthermore, the 17th January 2018, Europe approved draft measures to raise the share of renewable energy from 27% to 35% of the EU's energy mix by 2030 [9].

Across the Pacific, in the State of California, it was established by legislation [Senate Bill 1078 (Chapter 516, Statutes of 2002)] [10], the goal of 33% of generation by 2020 to be sourced by renewable energy, and of 50% by 2030. And more relevant to the paper, in June 2012, Governor Jerry Brown stated that 12000 MW should come from DG by 2020 [11]. Regarding the 33% and 50% renewable generation goal, it is expected California not only achieves the 33% by 2020, but the 2030 goal of 50% of renewable energy by 2020, ten years before [12].On the other hand, the distribution generation goal is closed to be achieved, as for November 1st 2017, the report "California Energy Commission – Tracking Progress" [13] states that 10.520 MW of DRE are already deployed within the state, as Figure 2 indicates.

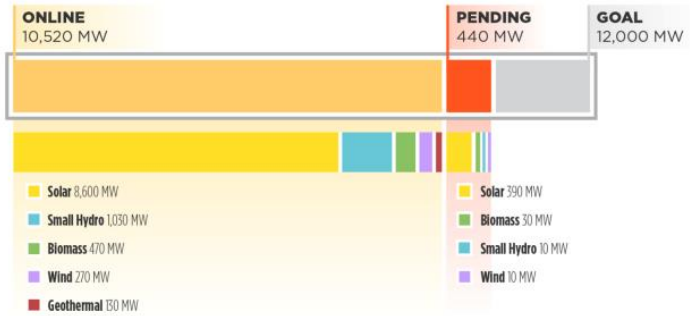


***Figure 2: Deployment goals of DRE in California** [13]*

2.4. Challenges and opportunities

On the last decades, Distributed Generation has been gathering momentum, and a great part of it is due to Renewable Energy. Distributed Generation is the vehicle for Renewable Energy growth, and its increase in presence across our distribution networks poses different challenges and opportunities that must be considered.

2.4.1. Opportunities/Advantages

- Increased supply security

  DG systems are the elementary part of Microgrids, which consist of "DG and interconnected loads within a clearly defined electrical boundary that acts as a single controllable entity with respect to the grid" [6]. These independent entities can act as an island in the event of a grid blackout or a natural disaster.

  An example of what DG systems can achieve is what has happened in Puerto Rico since Category 4 storm struck on September the 20th 2017. The combination of the hurricane and the old traditional fuel-based grid system where renewable energy stood only for a 2% of total generation [14] led to a total blackout. The transmission systems were knocked out, 80% of the lines were down after the storm passed, and the island was left for a week with no electric supply. On top of that, after more than a month less than 50% of the population of 3.5 million had electricity access [14].

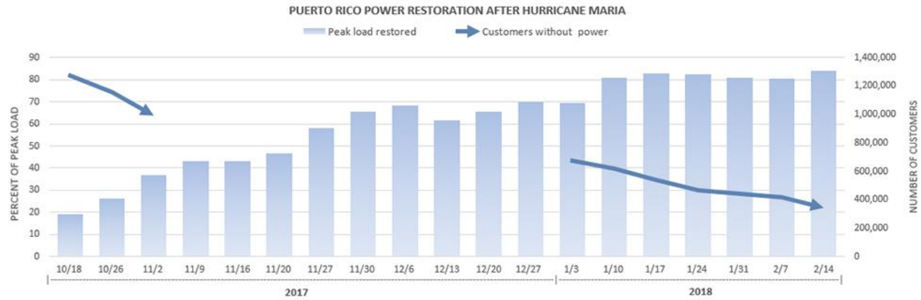


Figure 3: Evolution of Electric supply after the hurricane [14]

As old transmission lines were destroyed, the total system was useless. After more than 8 months, the system is not fully recovered, and on the 18th April 2018 a new total blackout occurred.

In parallel to the fast restoration of the old system, the island is rapidly developing a request for proposals for a new network system. José Ramón Morales, chairman of the Puerto Rico Energy Commission said that the island needs to "adopt and implement alternatives that allow greater resilience and faster restoration. Distributed generation technologies, such as microgrids, have the potential for restoring power to unserved areas and providing stability to recently reconnected areas".

DG systems technologies as microgrids, and minigrids, which are arrays of interconnected microgrid also capable to act in islanded mode or connected to the main grid, are considered in the projects of the companies submitting proposals for the new Puerto Rico's network system. The Figure 4 shows one of these projects, where a ring of interconnected minigrids would supply the great majority of the island population, while microgrids acting off-grid would supply rural interior areas.

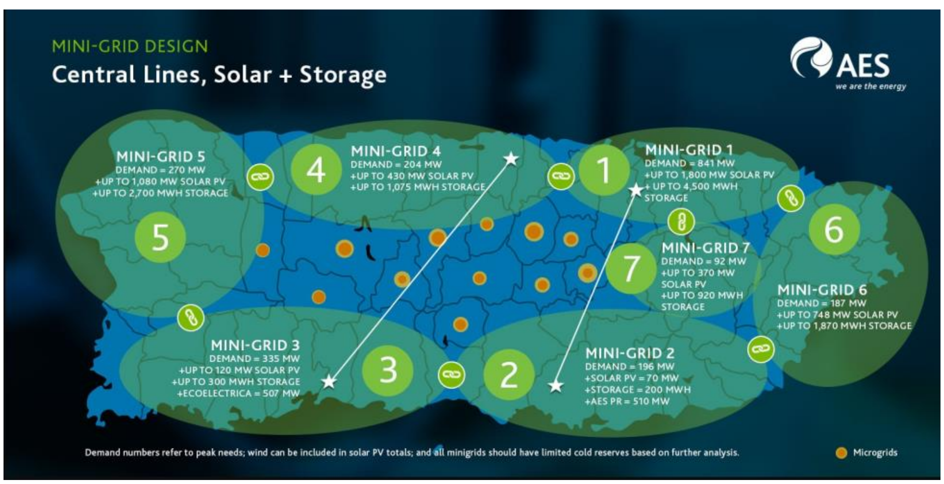


Figure 4: Puerto Rico electrical scenario [15]

➢ Reduction of power losses

Due to the fact that DG systems are located next to the loads, the transmission losses can be greatly reduced. According to the U.S. Energy Information Administration [14], for developed countries only transmission losses account amidst 6-9% of electricity generated, and at least a 10% for underdeveloped. The following Figure 5 shows the numbers for the critical issue of transmission losses for 12 of the most important countries from 1980 to 2010.

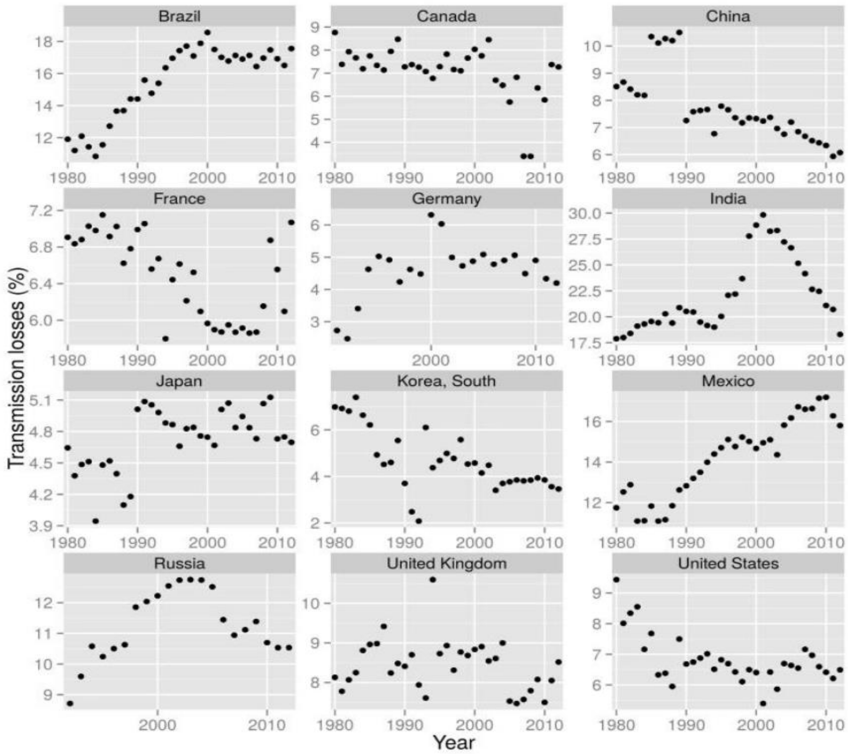


Figure 5: Evolution of transmission losses for 12 countries [16]

➢ Provision of ancillary services

DG systems can support the power transmission by regulating different parameters. This means, that the DG systems can improve the quality of the power provided by the grid, but the ability to control so many parameters (voltage, frequency, active and reactive power…) also has some issue, which will be extensively considered in Section 3.

➢ Reduction of pollutants

By the introduction of DRE, the greenhouse emissions and other pollutants can be reduced and even eliminated in some cases. It is also important to consider that other non-renewable DG systems can also contribute positively, as the advantage of smaller generators is that a much better efficiency can be achieved, versus the big traditional power plants.

➢ Easier to deploy

Compared to the traditional Generation Plants, distributed generation smaller plant size makes them more manageable and with more possible locations to deploy. DG systems can be deployed rapidly, and they do not create a great impact in the grid architecture, as few lines must be created.

- Boost competitiveness

The previous point makes it easier for new players to enter into the energy market, for both companies and clients. The number of start-ups related with DRE has sky rocketed, unleashing a bigger competition among the companies which translates into lower prices and better technology.

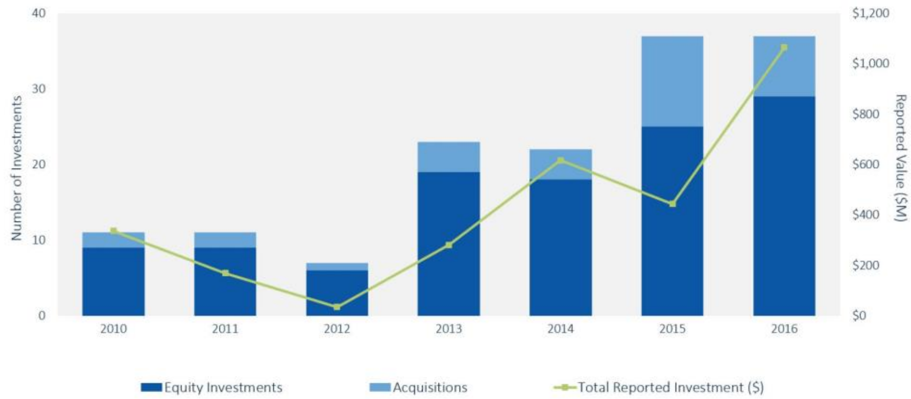


***Figure 6: Evolution of DRE based Start-Ups** [17]*

- Diversification and modularity

There are many types of DG systems as shown in Table 1, and modularity of some of them, especially renewable, allows greater spatial diversification than traditional power generation plants. This easy diversification and modularity nature of some DG systems improves the resilience of the supply to any damage from a single event.

- Customer Bill Savings

This advantage is widely acknowledged when Net metering is allowed under regulations, which is a billing mechanism that credits solar energy system owners for the electricity they add to the grid. However, it depends on each case, as not all the technology is feasible for every case.

- Potential to solve major World Challenges

According to the journal article "Access to Electricity as a Human Right" [18] , electrical access is a human right, but yet not accessible to a great amount of the population, see Figure 7. Underdeveloped countries have poor grid networks, that do not reach most of the country, and when loads are geographically dispersed, it is not profitable and poses a challenge to develop new lines. Diversification and easier deployment make DG systems a potential candidate to solve the challenge of providing access to electricity for underdeveloped countries or rural areas. Through Off-grid DG these communities can be partially or totally energized and relying on a diverse DRE portfolio a stable supply can be achieved.

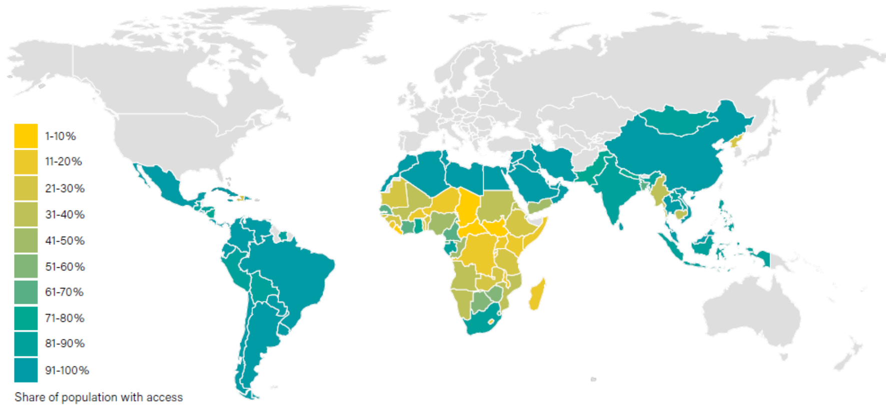


Figure 7: World Access to Electrical Supply [19]

2.4.2. Challenges

As well as the potential benefits already considered, the penetration of DG system involves several drawbacks. Some of the challenges are already being tackle, as power quality, while others will arise soon as the DG implementation keeps growing.

➢ Power Quality

Electric power quality, involves voltage, frequency, and waveform. When these three aspects are supplied steadily and in a smooth sinusoidal waveform function, it is said that the Power Quality of a system is good. DG systems significantly affect to these three parameters, they can produce voltage and frequency fluctuations, contribute to faults, harmonics, and other issues. This was the first issue to be regarded when DG started to be implemented, by means of specific distribution regulations and standards that were issued by different organizations. This paper will study several of this regulations and recommendations and analyze how the problem is being managed.

➢ Architecture of the distribution network

Traditional transmission distribution networks were design to accommodate a one direction flow of power, from the generation and transformers to the loads. But DG systems imply a power generation close to the loads, and when the generation exceeds the demand, there is a power flow in the opposite direction. This bi-directional flow is not supported by the traditional protective methods, based on common phase and ground non-directional overcurrent protection. This issue has not yet impacted the current electrical network, as the implementation of DG has not yet increased enough, but with the actual trend, the problem will arise soon. There are several plans on how to tackle the rising issue [20], on one hand, the current protection system could be redesigned to handle the two-way power flows. Other lines of thinking suggest that a complete new distribution architecture needs to be implemented, transforming it into a hybrid between distribution and transmission.

- Power reserve and storage

The fact that most of the DG growth is due to the implementation of renewable systems, will make generation dependent on the variability of natural resources, so fast reacting local power generation will have to be correctly managed. Industries are investing heavily on e-storage, which could be transformed into a top energy related industry in the coming years. According to the report World Energy Resources: "As of end-2015, the global installed storage capacity was 146 GW (including pumped hydro storage), consisting of 944 projects. Bottom-up projections suggest a global storage market of 1.4 GW/y by 2020 (excluding pumped hydro storage), with strong growth in electro-mechanical technologies in particular" [21]. However, it is not clear whether the technology is already enough developed to make the DG more competitive than the traditional generating industry, so Section 4 will address this question through the Study Case.

- Economic feasibility

It still not clear in which cases the DG is a feasible option in contrast to a common electrical supply. The paper will rely on the Section 3 Study Case to simulate different scenarios using different DG technologies and compare the economic turn out of DRE in contrast with scenarios with less renewable penetration, and with figures from the conventional system.

3. Regulations

3.1. Introduction

Power quality issue has been addressed by different regulations, issued by companies, organizations, and countries. The regulations state different technical requirements that tackle the grid havoc that otherwise, not controlled DG systems could create. However, such a variety of standards can lead to confusion and misunderstanding, and to solve this issue, this paper will introduce and explain main the technical requirements for DG systems to be connected to the grid and provide a general picture of the limits of each of them. To do so, a comparative study on how regulations address power quality will be shown and analyzed. The paper has considered the 37 regulations that appear in Table 2, and a further explanation of the main standards in the table can be found in Annex B.

Standard	Title
G59	Recommendations for the connection of generating plant to the distribution systems of licensed distribution network operators [22]
G83	Recommendations for the Connection of Type Tested Small-scale Embedded Generators (Up to 16A per Phase) in Parallel with Low-Voltage Distribution Systems [23]
GB/T 19964-2012	Technical requirements for connecting photovoltaic power station to power system [24]
IEC 61727	Photovoltaic (PV) systems – Characteristics of the utility interface [25]
IEEE 1547	Standard for Interconnecting distributed resources with electric power systems [2]
Official India gazette No 12/X/STD(CONN)/GM/CEA	Distributed generation Notification India [26]
UL 1741	Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources [27]
UNE EN 206007	Requisitos de conexión a la red eléctrica para inversores [28]
UNE EN 50438	Requirements for micro-generating plants to be connected in parallel with public low-voltage distribution networks [29]
VDE-AR-N 41052	Power generation systems connected to the low-voltage distribution network [30]
BDEW	Technical Guideline Generating Plants Connected to the Medium-Voltage Network [31]
ÖVE/ÖNORM E 8001-4-712	Construction of electrical installations with nominal voltages up to AC 1000 V and DC 1500 V-part 4-712: Photovoltaic power generation plants-installation and safety requirements [32]
CENELEC 10/11	Connection requirements for generators to distribution grid [33]
Cyprus	(I)
Operational rules for distribution networks for Czech Republic	(I)
Denmark	(I)
Spain RD 1699/2011	Real Decreto 1699/2011, de 18 de noviembre, por el que se regula la conexión a red de instalaciones de producción de energía eléctrica de pequeña potencia. [34]
Finland	(I)
DTIS-230206-BRL	Conditions Governing the Connection and Operation of Micro-generation [35]
EN 61000-4-30	Testing and measurement techniques - Power quality measurement methods [36]

Latvia Elektroenerģijas tirgus likums,	Electricity Market Law [37]
The Netherlands	(I)
Slovenia Uradni list RS No. 41/2011	Official Journal of the Republic of Slovenia No. 41/2011 [38]
Sweden	(I)
TOR D4 (02/2016)	Technical and organisational rules for operators and users of grids, paralell operation of generating plants with distribution grids. [39]
Greece Government Gazette B/103 2015	Grid Code [40]
JEAC 9701-2012	Grid Interconnection Code [41]
NA/EEA-CH 2014	Switzerland- Recommendation mains connection for Power generation plants: Technical requirements for connection and parallel operation in NE 3 to NE7 [42]
AS 4777.2	Grid Connection of Energy Systems via Inverter Requirements [43]
IEEE 929	Recommended Practice for Utility Interface of Photovoltaic (PV) Systems [44]
IEEE Std 519	IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems [45]
ENA EREC G5	Planning Levels For Harmonic Voltage Distorsion And The Connection of Non-Linear Equipment To Transmission Systems And Distribution Networks In The United Kingdom [46]
ENA EREC P28	Planning Levels for voltage fluctuations caused by industrial, commercial and domestic equipment in the United Kingdom [47]
UNE-EN-61000 3-3	Limits - Limitation of voltage changes, voltage fluctuations and flicker in public low-voltage supply systems, for equipment with rated current ≤16 A per phase and not subject to conditional connection [48]
UNE-EN-61000 3-2	Limits - Limits for harmonic current emissions (equipment input current ≤16 A per phase) [49]
UNE 206006 IN:2011-05-30	Performance tests for islanding detection of multiple grid-connected photovoltaic inverters in parallel [50]
ENA EREC P25	The short-circuit characteristics of single-phase and three-phase low voltage distribution networks. [51]

Table 2: Considered Standards in the paper

(I) The parameters of the regulation were displayed in UNE EN 50438.

3.2. Technical requirements

The analysis and study of the regulations on Table 2, especially from the ones which are directed to distribution systems, has permitted to define the recurrent power quality issue. These issues are managed through technical requirements set to the generators and inverters in the regulations. For example, to prevent over voltage, the standards set an operating voltage range where the DG systems shall operate, and a disconnection time in case the voltage falls out of the range.

Notice that the reference of the regulations has been done in the table, and will not be repeated along Section 3.

3.2.1. Allowed Voltage and Frequency Ranges

Voltage and frequency operating ranges serve as foundation for other technical requirements. For example, ancillary services shall only be provided once these parameters are out of their normal limits. Reconnection shall only take place once voltage and frequency are within the limits, or islanding condition shall be verified thanks to these ranges. It is because of this, that setting proper frequency and voltage ranges are a key aspect of any regulation, and the technical requirement that will be considered first.

3.2.1.1. Comparative Regulation Study

Voltage and frequency operating ranges and clearing times when these parameters are out of acceptable limits are stated in most standards and regulations. The relevant information from 23 different recommendation, regulations and standards has been extracted, and presented in Table 3. For an easier comparison, the voltage ranges have been transformed into percentage of deviation.

Standard			Parameter	Range Set (%) & (Hz)	Maximun clearing time (s)	Minimun clearing time (s)
G59	Voltage (%)		Over Voltage Step 2	V > 115,5	0,48	
			Over Voltage Step 1	112,37 < V <115,5	0,98	
			Continuous operation	85 < V < 115,5		
			Under Voltage Step 1	78 < V < 85	2,48	
			Under Voltage Step 2	75 < V < 78	0,48	
	Frequency (Hz)		Over Frequency Step 1	51,5 < f < 52		90
			Continuous operation	47,5 < f < 51,5		
			Under Frequency Step 1	47 <f < 47,5		20
G83	Voltage (%)	GROUP 1 Single unit within a single customer's installation	Over Voltage Step 1	V > 114	1	
			Continuous operation	87 < V < 114		
			Under Voltage Step 1	V < 87	2,5	
		GROUP 2 Multiple units in a close geographic region, under a planned programme of work	Over Voltage Step 1	V > 119	0,5	
			Continuous operation	80 < V < 119		
			Under Voltage Step 1	V < 80	0,5	
	Frequency (Hz)	GROUP 1 Single unit within a single customer's installation	Over Frequency Step 1	f > 51,5		90
			Continuous operation	47,5 < f < 51,5		
			Under Frequency Step 1	f <47,5		20
		GROUP 2 Multiple units in a close geographic region, under a planned programme of work	Over Frequency Step 1	f > 52		0,5
			Continuous operation	47 < f < 52		
			Under Frequency Step 1	f <47		0,5
GB/T 19964-2012	Voltage (%)		Over Voltage Step 2	120 < V < 130		Continuous operation at least 0,5 s
			Over Voltage Step 1	110 < V < 120		Continuous operation at least 10 s
			Continuous operation	90 < V < 110		Continuous operation
			Under Voltage Step 1	V < 90		Clause 8 shall apply
	Frequency (Hz)		Over Frequency Step 2	f > 50,5		Immediate disconnection
			Over Frequency Step 1	50,2 < f < 50,5		Continuous operation for at least 2 min
			Continuous operation	49,5 < f < 50,2		Continuous operation
			Under Frequency Step 1	48 < f < 49,5		System shall operate for at least 10 min
			Under Frequency Step 2	f < 48		To be determined depending of the inverter

IEC 61727	Voltage (%)	Over Voltage Step 2	V > 135	0,05 s	
		Over Voltage Step 1	110 < V < 135	2,0 s	
		Continuous operation	$85 \leq V \leq 110$		
		Under Voltage Step 1	$50 \leq V < 85$	2,0 s	
		Under Voltage Step 2	V < 50	0,1 s	
	Frequency (Hz)	Over Frequency Step 1	f < 49	0,2 s	
		Continuous operation	49 < f < 51		
		Under Frequency Step 1	f < 49	0,2 s	
IEEE 1547	Voltage (%)	Over Voltage Step 2	$V \geq 120$	0,16	0,16
		Over Voltage Step 1	110 < V < 120	13	1
		Continuous operation	88 < V < 110		
		Under Voltage Step 1	$60 \leq V < 88$	21	2
		Under Voltage Step 2	$45 \leq V < 60$	11	1
		Under Voltage Step 3	V < 45	0,16	0,16
	Frequency (Hz)	Over Frequency Step 2	f > 62	10	0,16
		Over Frequency Step 1	60,5 < f < 62	300	2
		Continuous operation	59,5 < f < 60,5		
		Under Frequency Step 1	57 < f < 59,5	300	2
		Under Frequency Step 2	f < 57	10	0,16
Official India gazette No 12/X/STD(CONN)/GM/CEA	Voltage (%)	Over Voltage Step 1	$V \geq 110$	2	
		Continuous operation	$80 \leq V < 110$		
		Under Voltage Step 1	V < 80	2	
	Frequency (Hz)	Over Frequency Step 1	f > 50,5	0,2 s	
		Continuous operation	47,5 < f < 50,5		
		Under Frequency Step 1	f < 47,5	0,2 s	
UL 1741	Voltage (%)	Over Voltage Step 1	$V \geq 110$	Not specified	
		Continuous operation	$90 \leq V < 110$		
		Under Voltage Step 1	V < 90	Not specified	
	Frequency (Hz)	Over Frequency Step 1	f > 61	Not specified	
		Continuous operation	59 < f < 61		
		Under Frequency Step 1	f < 59	Not specified	
EN 50438	Voltage (%)	Over Voltage Step 2	$V \geq 115$	0,2 s	0,1 s
		Over Voltage Step 1	$110 \leq V < 115$	3 s	-
		Continuous operation	$85 \leq V < 110$		
		Under Voltage Step 1	V < 85	1,5 s	1,2 s
	Frequency (Hz)	Over Frequency Step 1	f > 52	0,5 s	0,3 s
		Continuous operation	49 < f < 51		
		Under Frequency Step 1	f < 47,5	0,5 s	0,3 s

VDE-AR-N 41052011-08	Voltage (%)		Over Voltage Step 1	V ≥ 110	0,2	0,1
			Continuous operation	80 ≤ V < 110		
			Under Voltage Step 1	V < 80	0,2	0,1
	Frequency (Hz)		Over Frequency Step 1	f > 51,5	0,2	0,1
			Continuous operation	47,5 < f < 51,5		
			Under Frequency Step 1	f < 47,5	0,2	0,1
BDEW	Voltage (%)	Group 1 Protection connected at network point of connection	Over Voltage Step 2	V > 115	0,1	
			Over Voltage Step 1	108 < V < 115	60	
			Continuous operation	80 < V < 108		
			Under Voltage Step 1	V < 80	2,7	
		Group 2 Protection connected at generating unit connected to the bus-bar of a transformer station	Over Voltage Step 1	V > 120	0,1	
			Continuous operation	120 < V < 80		
			Under Voltage Step 1	45 < V < 80	1,5 to 2,4	
			Under Voltage Step 2	V < 45	0,3	
		Group 3 Protection connected at generating unit.	Over Voltage Step 1	V > 115	0,1	
			Continuous operation	115 < V < 80		
			Under Voltage Step 1	45 < V < 80	1	
			Under Voltage Step 2	V < 45	0,3	
	Frequency (Hz) (I)		Over Frequency Step 1	f > 51,5	0,1	
			Continuous operation	47,5 < f < 51,5		
			Under Frequency Step 1	f < 47,5	0,1	
Austria ÖVE/ÖNORM E 8001-4-712	Voltage (%)		Over Voltage Step 1	V > 115	0,2	
			Under Voltage Step 1	V<80	0,2	
	Frequency (Hz)		Over Frequency Step 1	f > 51	0,2	
			Under Frequency Step 1	f < 47	0,2	
Belgium CENELEC 10/11	Voltage (%)		Over Voltage Step 2	V > 115	0	
			Over Voltage Step 1	110 < V <115	0	
			Continuous operation			
			Under Voltage Step 1	V < 80	0	
			Under Voltage Step 2	180 < U < 188	0	
	Frequency (Hz)		Over Frequency Step 1	f > 51,5	0	
			Continuous operation			
			Under Frequency Step 1	f < 47,5	0	
Cyprus	Voltage (%)		Over Voltage Step 1	V > 110	0,5	
			Under Voltage Step 1	V<90	0,5	
	Frequency (Hz)		Over Frequency Step 1	f > 52	0,5	
			Under Frequency Step 1	f < 53	0,5	

Czech Republic Operational rules for distribution networks	Voltage (%)	Over Voltage Step 1	V > 115	0,2	
		Over Voltage Step 1	V < 85	0,2	
	Frequency (Hz)	Over Frequency Step 1	f > 52	0,5	
		Under Frequency Step 1	f < 47,5	0,5	
Denmark	Voltage (%)	Over Voltage Step 2	V > 113	0,2 s	0,1 s
		Over Voltage Step 1	110 < V <113	40 s	39 s
		Under Voltage Step 1	V < 90	10 s	9 s
	Frequency (Hz)	Over Frequency Step 1	f > 52	0,2 s	0,1 s
		Under Frequency Step 1	f < 47,5	0,2 s	0,1 s
Spain RD 1699/2011	Voltage (%)	Over Voltage Step 2	V > 115	0,2	
		Over Voltage Step 1	110 < V <115	1,5	
		Under Voltage Step 1	V < 85	1,5	
	Frequency (Hz)	Over Frequency Step 1	f > 50,5	0,5	
		Under Frequency Step 1	f < 48	3	
Finland	Voltage (%)	Over Voltage Step 1	V > 110	0,2	
		Under Voltage Step 1	V < 85	0,2	
	Frequency (Hz)	Over Frequency Step 2	f > 51,5	0,2	
		Over Frequency Step 1	51,5 > f > 51		30 min
		Under Frequency Step 1	47,5 < f < 49		30 min
		Under Frequency Step 2	f < 47,5	0,2	
Ireland DTIS-230206-BRL	Voltage (%)	Over Voltage Step 1	V > 110	0,5	
		Over Voltage Step 1	V < 90	0,5	
	Frequency (Hz)	Over Frequency Step 1	f > 50,5	0,5	
		Under Frequency Step 1	f < 52	0,5	
Italy EN 61000-4-30	Voltage (%)	Over Voltage Step 2	V > 115	0,2	
		Over Voltage Step 1	110 < V < 115	603	
		Under Voltage Step 1	40 < V < 85	0,4	
		Under Voltage Step 2	V < 40	0,2	
	Frequency (Hz)	Over frequency Step 2	f > 51,5	0,1	
		Over frequency Step 1	51,5 > f > 50,5	0,1	
		Under frequency Step 1	49,5 > f > 47,5	1,0 (or 0,1)	
		Under frequency Step 2	f < 47,5	4,0 (or 0,1)	
Latvia Elektroenerģijas tirgus likums, 05.05.2005 (Electricity Market Law)	Voltage (%)	Over Voltage Step 1	V > 111	1,5	
		Over Voltage Step 1	V < 89	3	
	Frequency (Hz)	Over Frequency Step 1	f > 50.5	0,5	
		Under Frequency Step 1	f < 50,8	0,5	
The Netherlands	Voltage (%)	Over Voltage Step 1	V > 110	2	
		Over Voltage Step 1(II)	V < 80	2	
	Frequency (Hz)	Over Frequency Step 1	f > 51	2	
		Under Frequency Step 1	f < 52	2	

Slovenia Uradni list RS (Official Gazzette of the Republic of Slovenia) No. 41/2011	Voltage (%)	Over Voltage Step 2	V > 115	0,2	
		Over Voltage Step 1	111 < V < 115	1,5	
		Under Voltage Step 1	60 < V < 85	1,5	
		Under Voltage Step 2	V < 60	0,2	
	Frequency (Hz)	Over Frequency Step 1	f > 51	0,2	
		Under Frequency Step 1	f < 47	0,2	
Sweden	Voltage (%)	Over Voltage Step 2	V > 115	0,2	
		Over Voltage Step 1	111 < V < 115	60	
		Under Voltage Step 1	V < 85	0,2	
	Frequency (Hz)	Over Frequency Step 1	f > 51	0,5	
		Under Frequency Step 1	f < 47	0,5	

Table 3: Analysis of voltage & frequency limitation

(1): In case of traditional generators (non inverter based) with nominal power of the generating plant not higher than 6 kW, it is possible to adopt a clearance time = 0 s

(2): Mandatory for inverter based generating plants with nominal power of the generating plant not higher than 6 kW

(3): For voltage values $V \leq V_n$, frequency protection shall inhibit (no trip)

(4): Threshold enabled only with “external signal input” = “high” and “local command” =“high”

(5): See following scheme and its operating description

(6): For inverter based generating plants, through “local command” setting = “low”, these thresholds may be permanently excluded

3.2.1.2. Analysis

The objective for the analysis before obtaining the results was to create a graphic display of the deviation in the operating ranges, and disconnection times, but the great divergences among regulations make it impossible.

In the case of the voltage, each regulation sets out different limits, some of them with progressive ranges of disconnection, while others not. For the disconnection times, there are critical differences in standards like the IEEE 1547, specially for the undervoltage ranges. This standard permits the DG systems to work for long times in under voltage levels that other regulations as the VDE-AR-N 41052011-08 orders to be cleared in less than seconds. There is a great variability in all the data obtained, and it can be generally observed that European regulations deploy more strict limits than the rest. This great variability is partially explained since these regulations apply for different countries which have different voltage limits and different grid architectures. This difference in architecture implies that some countries may have to allow a wider range of operating ranges or longer disconnection times, as parts of their networks suffer more usually voltage distortions.

For the frequency, the results are closer to what was hypothesized, which was a restriction resemblance among the studied regulations. Frequency cannot vary as much as the voltage, which is transformed several times across the grid, and because of it, the frequency limits have some degree of homogeneity. However, the clearing times are still not consolidated between different countries, even within the European Union. The frequency value is uniform all over Europe, and the operating ranges are very similar as the Table 3 shows, but the clearance times are still far away from each other.

3.2.2. Voltage support

This point refers to the DG acting as a voltage regulator for the system, by means of reactive power injection or absorption. The generator can act under excited or over excited to stabilize the grid.

Some regulations state that DG should only operate at unity power factor, providing only active power to the utility. This design maximizes the benefits of the individual customer, since residential customers are usually charged only for the active power that they draw from the grid, however it does not take advantage of the benefits that DG systems can provide with the ancillary services. By means of the reactive power, the DG systems are able to regulate the voltage, as an injection of reactive power has the capacity of increasing the voltage in the area, and a consumption of reactive can lower it.

For this, some standards provide an allowable power factor range where the DG can work. When the DG systems power factor lags, it absorbs reactive power, and hence, it is able to reduce the voltage in the area, and the opposite happened when it leads. This reduction or rise depends on each case, as a DG system placed at the end of a long distributed line that is heavily loaded will have a greater impact than the DG systems that are placed at more resilient points of the lines.

There are several types of voltage support, which generally depend on the degree of voltage distortion that is detected at the Point of Common Coupling (PCC). For small and gradual voltage deviations, static voltage control will be performed, while for sudden considerable deviations, dynamic control shall be performed.

- **Steady or Static Voltage Control**

  This type of control is continuously being performed by the DG systems, and are small corrections of the voltage levels at the PCC. The voltage does not have to be out of the operating range for the static control to occur.

- **Dynamic Voltage Control**

  This type of control shall be required after critical voltage drop or rise occurred in the high voltage network that is transmitted to the distribution network, potentially triggering unintentional disconnections on the DG systems. To prevent this Over/Under voltage disconnections, the following points shall be considered:

  - A minimum delay time shall exist, during which the DG Systems will try to stabilize the voltage. The following figure shows, and example of specific minimum delay set by a regulation for the intention of allowing dynamic support. While the voltage does not drop below the red line for the given time in the x/axis, disconnection must be avoided.

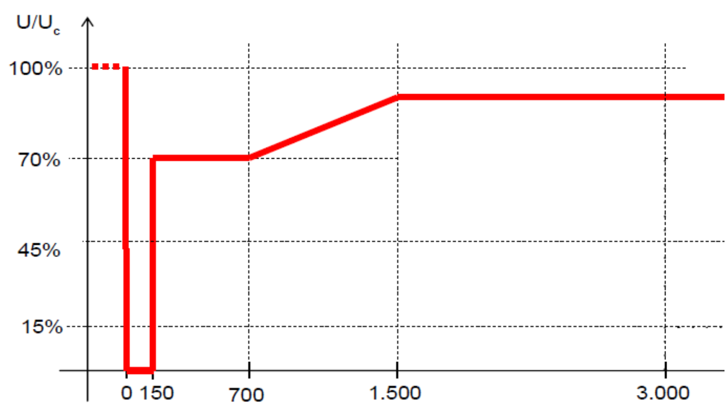


Figure 8: Disconnection parameters for under voltage [15]

  - Support the network voltage during a network fault by feeding or consuming reactive current into the network. This urgent support will be performed in the time window called delay time. If after the delay time, the reactive power provided by the DG systems has not stabilized the voltage level, then disconnection can take place.

3.2.2.1. Comparative Regulation Study

The 16 recommendations in Table 4 have been analyzed in order to study the methodology in which voltage support is considered. There is no specific guidance on how to support the voltage as it exists for frequency support, however, the regulations define a power factor range where they can operate. For example, once the voltage is falls below the limits from Table 2, the DG shall operate overexcited at a lagging power factor up to 0,95. The opposite would happen when the voltage exceeds the upper limit of Table 2.

Standard	Reactive Power Capability
G59	0.95 lagging to 0.95 leading
G83	range 0.95 lagging to 0.95 leading
GB/T 19964-2012(I)	P>50% 0.98 lagging to 0.98 leading 20% < P < 50% 0.95 lagging to 0.95 leading
IEC 61727	0.90 lagging to 0.90 leading
IEEE 1547	Voltage support is out of the scope.
India Decree	0.85 lagging to 0.95 leading
UL 1741	Not included in standard
UNE EN 206007	Not included in standard
UNE EN 50438	0.90 lagging to 0.90 leading
VDE-AR-N 41052011-08	LV & MV --> 0.95 lagging to 0.95 leading HV --> 0.90 lagging to 0.90 leading
BDEW	0.95 lagging to 0.95 leading
Austria TOR D4 (02/2016)	MV: 0.925 lagging to 0.925 leading LV: 0.90 lagging to 0.90 leading
Belgium C10/11 SYNERGRID	**Installations < 1MVA** cosϕ > 0,95 **Installations > 1MVA DG** can inject or absorb reactive power between -0,1P_{nom} to 0,33 P_{nom}
Greece Grid Code, Government Gazette B/103 2015 (II)	0.95 lagging to 0.95 leading
Japan JEAC 9701-2012	MV: 0,85 lagging to 1,00 leading LV: 0,85 lagging to 1,00 leading
Switzerland NA/EEA-CH 2014	0.90 lagging to 0.90 leading

Table 4: Analysis of voltage support

(I) Maximun power change rate is 10% of the nominal capacity per minute
(II) Distributed System Operator (DSO) can specify different ranges

3.2.2.2. Analysis

Most of the studied regulations considered working at a non-unity power factor to improve the service. Some of them proposed wider ranges tan others, as it is the case of the India Decree.

Regarding the other papers, it has been noticed that Japan does not allow injection of reactive power into the grid by the DG system but is does allow the absorption.

3.2.3. Frequency support

When there exists an unbalance between demand and generation, the network frequency tends to vary, sometimes falling out of the operating ranges established in Table 2. DG systems have the ability to avoid further disturbances by scheduling generation to match demand. As an example, when the load is superior to the generation, causing the grid frequency to drop, the DG are capable of increasing the active power contribution matching generation to demand and stabilizing the frequency.

3.2.3.1. Comparative Regulation Study

Generally, the standards that consider frequency control, set up a frequency value from which the generator will start increasing or decreasing the rate of active power contribution per Hz.

However, and in contrast with the voltage support, frequency support is only considered by 4 of the analyzed regulations, and in different ways for each of them. While the Chinese standard does not provide the necessary data for the implementation, and further recommendations about the topic shall be studied, the EN 50438 and both German standards go into the detail of how this ancillary service shall be performed.

GB/T 19964-2012

It is stated that the power station shall be equipped with active power control system, capability to continuously and smoothly adjust active power and ability to participate in active power control of system.

When power system frequency is greater than 50.2 Hz, the standard articulates that the DG system shall reduce its active power contribution according to instructions of grid scheduling mechanism or disconnect if the deviation is serious.

EN 50438

Regarding frequency support, a generating plant shall be resilient to reductions and increase of frequency at the point of connection while varying the maximum power as little as possible. The following Table 5, shows the minimum required period the generating plant shall operate before disconnection for the given frequency ranges. During this period, the Generating Units shall actively regulate the frequency by means of active power as will be explained.

Frequency range	Time period for operation
51 Hz – 51,5 Hz	30 min
47,5 Hz – 49 Hz	30 min

Table 5: Ranges of possible frequency support

The generator shall be capable of activating active power frequency response as fast as technically feasible with an initial delay that shall be as short as possible with a maximum of 2 s. If the initial delay is below 2 s an intentional delay shall be programmable to adjust the total response time to a value between the initial response time and 2 s.

This delay has as purpose avoiding the creation of an unintentional stable island. If the delay did not exists, and a fault in the system occurs, the frequency support would instantaneously start working, and in cases where the load is not very high, the DG system could create an stable islanded system. However, a delay time in the frequency response means that if the frequency variation is caused by loss of mains, in the 2 seconds the frequency will fall out the limits imposed in Table 5, triggering automatic disconnection.

- Under- frequency Support

It is important to notice that EN 50438 does not consider an increase in active power for under frequency, but it limits the admissible active power reduction in the following way. The maximum admissible active power reduction due to under-frequency below 49,5 Hz is limited by a reduction rate of 10 % of the momentary power P_M per Hz as long as the frequency does not drop from 49 Hz. In case it falls below, the maximum reduction of active power shall be 2% per Hertz, as the dashed line shows.

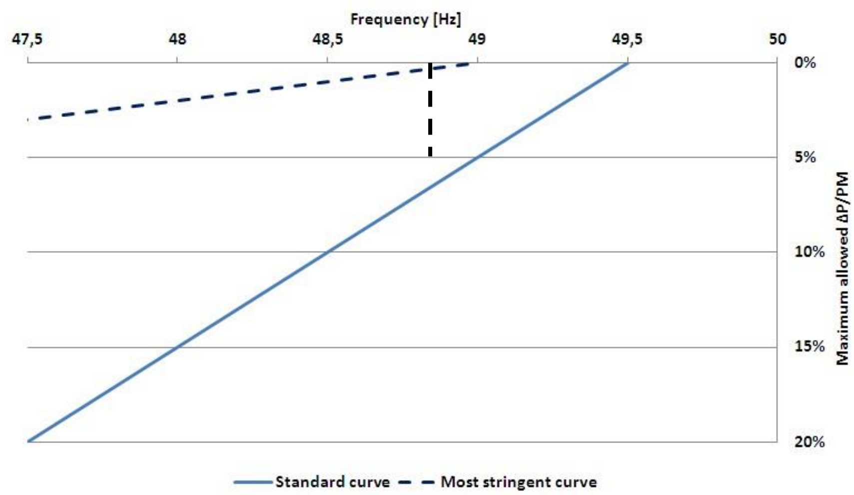


Figure 9: Under frequency active power contribution

- Over - frequency Support

In case of over frequency, it does consider an active power reduction, which shall start as soon as the frequency exceeds 50,2 Hz and is limited by a decrease rate of 12 % of the momentary power ($P_{M)}$ per 1 Hz and the minimum increase is set to be 2 % of the momentary power (P_M) per 1 Hz. This percentages correspond to a gradient of 100 % P_M /Hz – 16,7 % P_M /Hz respectively.

VDE-AR-N 4105:2011-08

For over frequency, the working range where frequency support by means of active power regulation is allowed is from 50,2 Hz to 51,5 Hz.

Once the lower limit of 50,2 HZ is exceeded, the DG system shall reduce (for frequency increase) or increase (for frequency decrease) the active power with a fixed gradient of 40% of active power per Hertz. In the event of the disconnection frequency being exceeded, the power generation system shall disconnect from the network within a maximum period of one second.

For under frequency, it is not clear whether the standard admits active power regulation or not, what is clear is that the considered range is from 47,5 Hz to 50,0 Hz, and that no disconnection is permitted while the frequency remains within the limits. In the event of the disconnection frequency being exceeded, the power generation system shall disconnect from the network within a maximum period of one second.

BDEW- Technical Guideline

The BDEW allows the DG system to actively regulate the network frequency. The case that is considered is over frequency, if the frequency reaches a value of 50.2 Hz, active power shall be reduced by all DG systems with a gradient of 40% of the generator’s instantaneously available capacity per Hertz.

Once the frequency returns to a value of $f \leq 50.05$ Hz, the active power can be increased again to normal parameters.

3.2.3.2. Analysis

There are three relevant parameters when standards address the frequency support, which are active power response delay, operating window of frequencies and active power contribution rate. The EN 50438 addresses the three of them, and on the opposite the Chinese only considers the active power contribution. The German regulations state the disconnection time in case the frequency range where the DG system, can provide support is passed, but this data is already available in Table 2, and as no delay is considered to start frequency support, a conflict between islanding detection and frequency support can arise.

Regarding the active power contribution gradients, the European standard defines a range between 16,7 % and 100% P_M /Hz, while the Germans stablish a fixed rate of 40% P_M /Hz.

3.2.4. Reconnection

After an outage or fault the DG Systems shall be disconnected, and as soon as the Network parameters return to normal levels, restoration of the supply is considered. For connecting the DG Systems back into the system, some points need to be consider.

Regarding common grid standards, there are 4 aspects that need to be secured before reconnection [52].

1. Phase sequence

    The generator three phase sequence must match the grid three phase sequence.

2. Voltage magnitude

    The voltage from both sides must be paired before the connection, in case it is not, to possible outcomes arise:

    - When the generated voltage is greater than the grid voltage, the generator will be over-excited and introduce MVAR.
    - If the grid voltage is greater than the generator voltage, the generator will be under-excited and absorb MVAR.

3. Frequency

    The frequency at both sides must be equal. If the generators frequency is lower than the grid, the generator would try to catch up and the stator and rotor could start slipping poles, damaging the generator.

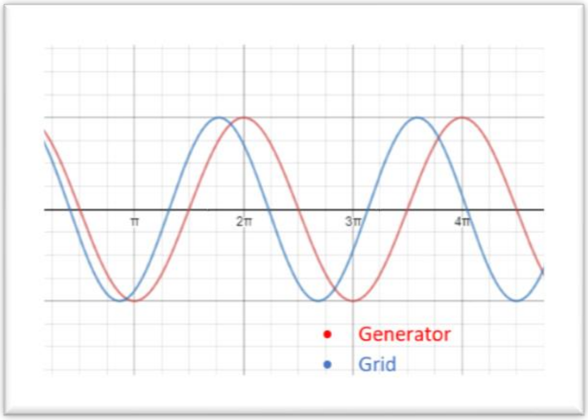


Figure 10: Generator slower than the grid

4. Phase angle

    Phase angle between the grid voltage and generator voltage must be 0, in opposite at what Figure 11 shows.

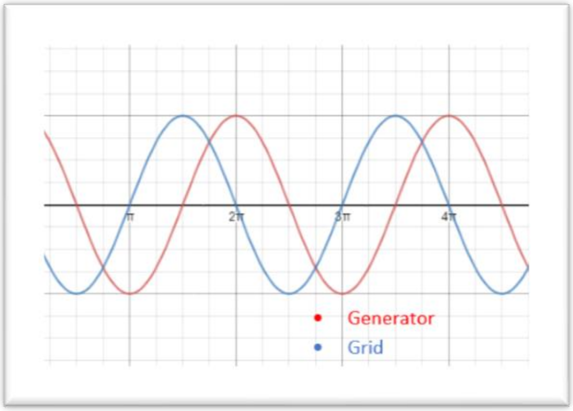


Figure 11: Phase angle shift

3.2.4.1. Comparative Regulation Study

Regarding reconnection, the 12 following standards were considered, and the summary of their considerations are shown in Table 6.

From the experience, it can be stated that standards refer briefly to reconnection limitations. The parameters provided are generally the secured aspects before reconnecting, and a delay time the generator shall prove that the condition is satisfied.

Standard	Condition	Delay
G59	Voltage and frequency must be within the allowable ranges	At least 20s
G83	Voltage and frequency must be within the allowable ranges	At least 20s
GB/T 19964-2012	According to scheduling instructions	
IEC 61727 (I)	Voltage and frequency must be within the allowable ranges	From 20 s to 5 min
IEEE 1547	Frequency within 59, 3 Hz and 60,5 Hz and voltage within the normal operating range	Up to 5 min
India Decree	Voltage and frequency must be within the allowable ranges	At least 60 s
UL 1741	Not considered	
UNE EN 206007	Spanish Operation Procedure P.O.1.6 Frequency within 49, 5 Hz and 50,5 Hz and voltage within the normal operating range	At least 3 min
UNE EN 50438	Explained below	
VDE-AR-N 41052011-08 (II)	Frequency within 47, 5 Hz and 50,05 Hz and voltage within range of 85% to 110%	At least 60 s
BDEW (III)	Frequency within 47, 5 Hz and 50,05 Hz and voltage at least 95 % nominal	At least 60 s
CE10/11 (IV)	Frequency within 47, 5 Hz and 50,05 Hz and voltage between 85% and 110% the nominal	At least 60 s

Table 6: Analysis of reconnection configuration

(I) Only considered for reconnecting after tripping

(II) After manual operations performed to the DG system, such as initial start-up, or maintenance, the reconnection might not follow the previously

(III) For generating plants of more than 1 MVA, it needs to be proven also that the active power increases with a maximum gradient of 10% of the rated power per minute.

(IV) Maximum allowed active power gradient shall be 10 % Pn/min

UNE EN 50438

The EN 50438 makes a distinction between reconnection after tripping and when the generator starts working after a normal stop. The parameters that shall be controlled are the same for both cases, although there is a slight difference in the limits:

-After Tripping

- Frequency Range: 47,5 Hz < f < 50,05 Hz
- Voltage Range: 0,85 U_n< U < 1,10 U_n
- Minimum operating time within the limits: 60 s.
- Maximun variation of active power will be of 10% P_n/min unless otherwise specified by DSO.

-After normal stop

- Frequency Range: 47,5 Hz < f < 50,1 Hz
- Voltage Range: 0,85 U_n< U < 1,10 U_n
- Minimum operating time within the limits: 60 s.
- The variation of active power is left to be specified by the DSO.

3.2.4.2. Analysis

There are two types of reconnection standards can consider, the first one is after a fault, and the second one is after an intentional stop, as maintenance. However, all standards except EN 50438 use the same reconnection clause after tripping than after an intentional stop. Some of them demand the DG systems to operate within the normal operating ranges defined in Table 3 for a stated amount of time before reconnection, and others specify new ranges that are more restrictive than the normal operating conditions. The UNE EN 206007 is the most restrictive recommendation, with a narrow frequency window in which the generator shall operate for at least 3 minutes.

The EN 50438 states different frequency ranges but the same voltage range for both possible reconnecting scenarios. It then demands at least 60 second of operation, which apparently is a standard time, as other regulations also apply it.

3.2.5. Harmonics

Harmonics appear when the voltage or current coming from the generator's frequency is multiple of the fundamental frequency. For example, the third harmonic has three times the fundamental frequency, as shown below.

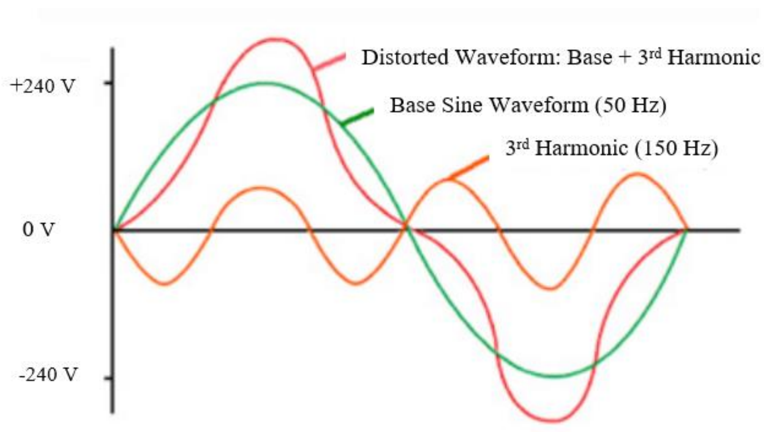


Figure 12: Sample of 3rd harmonic distortion

Ideally, an Alternate Current (AC) generator would provide a pure sinusoidal voltage, which means a perfectly distributed stator and field windings that operate in a uniform magnetic field. But the truth is, none of them are uniform in an AC machine, so they create distortions and the pure sinusoidal wave ends up having deviations.

At the point of generation, the harmonic distortion is usually relatively small (about 1% to 2 %) [53], and regulations are not so strict, but where DG systems are connected, in the distribution area, the harmonic presence is more important. The reason is that the load is the main cause of harmonic distortion across the grid, and DG harmonic contribution must be closely managed so as to not rise the already high amount of harmonics. The creation of harmonics in the loads is a point that will not be discussed in the paper, but nonlinear loads are the root cause of them.

In case of the DG Systems, electronics are the main reason for harmonic creation. The use in inverters in PV systems, or back to back converters, which create new waveforms can contribute to harmonics. Other less common causes of harmonics in the DG systems are the way in which the coils are disposed around the stator, which is normally not homogeneous, creating distortion in the output.

When a high level of harmonic distortion is present in electrical installations, a wide variety of problems may arise:

- Harmonics raise the current, in scales that sometimes can trip off the systems. But normally, by increasing the current they increase the waste of energy and equipment.
- Particularly, 3rd harmonic currents do not cancel out in three-phase systems. So current flows through the neutral phase causing dramatic overheating, and under prolongated episodes damage of the equipment.

3.2.5.1. Comparative Regulation Study

For harmonic control, the standards set a maximum harmonic current distortion to be introduced by the DG system in a form of percentage against the its nominal current. In addition, some standards provide the percental limit of distortion for each harmonic, which shall be taken into account together with the general percental limit.

Harmonic distortion is treated by the following 10 regulations. As each of them uses different parameters, it was not feasible to consolidate all the results in the same table, instead, for each regulation a table with its harmonic limits is shown, as well as a brief explanation:

G59

Regarding the contribution of harmonic distortion into the system, the G59 refers to EREC G5, (Engineering Recommendation G5/4-1). This recommendation is produced by Energy Network Association, and deals with Harmonic Voltage Distortion in transmission systems and distribution network for the United Kingdom.

The Harmonic distortion limits are classified in three groups depending on the system voltage at the PCC, and Total Harmonic Distortion (THD) are set for each voltage range in Table 7.

System Voltage at the PCC	THD Limit
400V	5%
6,6, 11 and 20kV	4%
22kV to 400kV	3%

Table 7: THD limits G5

Apart from the THD, the maximun distortion per harmonic order is also specified, in Table 8, Table 9 and Table 10 for each voltage range.

Odd harmonics (Non-multiple of 3)		Odd harmonics (Multiple of 3)		Even harmonics	
Order 'h'	Harmonic voltage (%)	Order 'h'	Harmonic voltage (%)	Order 'h'	Harmonic voltage (%)
5	4,0	3	4,0	2	1,6
7	4,0	9	1,2	4	1,0
11	3,0	15	0,3	6	0,5
13	2,5	21	0,2	8	0,4
17	1,6	>21	0,2	10	0,4
19	1,2			12	0,2
23	1,2			>12	0,2
25	0,7				
>25	0,2+ 0,5(25/h)				

Table 8: Limits for Harmonic Voltages in 400V System EREC G5

Odd harmonics (Non-multiple of 3)		Odd harmonics (Multiple of 3)		Even harmonics	
Order 'h'	Harmonic voltage (%)	Order 'h'	Harmonic voltage (%)	Order 'h'	Harmonic voltage (%)
5	30	3	30	2	15
7	30	9	12	4	10
11	20	15	03	6	05
13	20	21	02	8	04
17	16	>21	02	10	04
19	12			12	02
23	12			>12	02
25	0,7				
>25	0,2+ 0,5(25/ h)				

Table 9: Limits for Harmonic Voltages in 6,6kV, 11kV,and 20kV Systems EREC G5

Odd harmonics (Non-multiple of 3)		Odd harmonics (Multiple of 3)		Even harmonics	
Order 'h'	Harmonic voltaqe (%)	Order 'h'	Harmonic voltaqe (%)	Order 'h'	Harmonic voltaqe (%)
5	2,0	3	2,0	2	1,0
7	2,0	9	1,0	4	0,8
11	1,5	15	0,3	6	0,5
13	1,5	21	0,2	8	0,4
17	1,0	>21	0,2	10	0,4
19	1,0			12	0,2
23	0,7			>12	0,2
25	0,7				
>25	0,2+ 0,5(25/h)				

Table 10: Limits for Harmonic Voltages in Systems >20kV and <145 kV EREC G5

G83

The standard delegates Harmonic Regulation to the UNE-EN 6100-3-2, "Electromagnetic compatibility (EMC) - Part 3-2: Limits - Limits for harmonic current emissions (equipment input current ≤ 16 A per phase)". This standard deals with the limitation of harmonic current injected into public grid for systems with less than 16A of nominal current and sets out different limits depending on the harmonic origin (house appliances, portable tools, lighting equipment…). For the case being, the limits for Group A apply, shown in Table 11.

Harmonic Order n	Maximun admisible current A
Odd Harmonics	
3	2,30
5	1,14
7	0,77
9	0,40
11	0,33
13	0,21
$15 \leq n \leq 39$	15 * 15 / n
Even Harmonics	
2	1,08
4	0,43
6	0,30
$8 \leq n \leq 40$	0,23 * 8 / n

Table 11: Limits for harmonic current Group A EN 61000-3-2

GB/T 19964-2012

The applicable document for harmonic allowable limits is the GB/T 14549, which sets the THD for 6 different voltage rating at the PCC, and also the maximum total contribution for even and odd harmonics separately.

<table>
<tr><th rowspan="2">System Voltage at the PCC (KV)</th><th rowspan="2">Total Voltage Distortion (%)</th><th colspan="2">IndividualVoltage Distortionion % of U</th></tr>
<tr><th>Odd Order</th><th>Even Order</th></tr>
<tr><td>0,38</td><td>5,0</td><td>4,0</td><td>2,0</td></tr>
<tr><td>6</td><td rowspan="2">4,0</td><td rowspan="2">3,2</td><td rowspan="2">1,6</td></tr>
<tr><td>10</td></tr>
<tr><td>35</td><td rowspan="2">3,0</td><td rowspan="2">2,4</td><td rowspan="2">1,2</td></tr>
<tr><td>66</td></tr>
<tr><td>110</td><td>2,0</td><td>1,6</td><td>0,8</td></tr>
</table>

Table 12: Limits for harmonic voltage distortion GB/T 14549

IEC 61727

Table 13 and Table 14 define the maximum allowed current distortion.

Odd Harmonics	**Distortion limit**
3^{rd} through 9^{th}	Less than 4%
11^{th} through 15^{th}	Less than 2%
17^{th} through 21^{st}	Less than 1,5%
23^{rd} through 32^{nd}	Less than 0,6%

Table 13: Limits for odd Harmonic current distortion IEC 61727

Even Harmonics	**Distortion Limit**
2^{nd} through 8^{th}	Less than 1%
10^{th} through 32^{nd}	Less than 0,5%

Table 14: Limits for even Harmonic current distortion IEC 61727

The sum of all Harmonic current distortion must be less than 5% at rated inverter output. Limits for each harmonic are provided. Even harmonics in these ranges shall be less than 25 % of the lower odd harmonic limits listed.

IEEE 1547

The total harmonic current distortion emitted by DG systems apart from any harmonic already present in the grid is 5%. There are specific limits shown in the following Table 15 regarding odd harmonics.

Individual harmonic order (odd harmonics)[b]	h <11	11 h < 17	17 h < 23	23 h < 35	35 h	Total demand distortion
Percentage (%)	4,0	2,0	1,5	0,6	0,3	5,0

Table 15: Limits for harmonic current distortion IEEE 1547

For even harmonics, the limit is 25% of its respective odd harmonic,

Official India Gazette No 12/X/STD(CONN)/GM/CEA

Applicable limits are specified under IEEE 519, "Recommended Practice and Requirements for Harmonic Control in Electric Power Systems", which defines the current and voltage allowable introduction in the system.
Harmonic voltage distortion limits are specified in Table 16, for different PCC voltages.

Voltage V at PCC	Individual harmonic (%)	Total harmonic distortion THD (%)
V ≤ 1,0 KV	5,0	8,0
1 KV < V ≤ 69KV	3,0	5,0
69 kV < V ≤ 161 kV	1,5	2,5
161 kV < V	1,0	1,5

Table 16: Limits for harmonic voltage distortion IEEE 519

Harmonic maximum current distortion for different voltage ranges are specified in Table 17. The recommendation sets out limits for LV/MV and HV, however, HV limits were not relevant for the paper, so only the limits for the other two were extracted.

Maximum harmonic current distortion in percent of I_L						
Individual harmonic order (odd harmonics)						
I_{SC}/I_L	3 ≤ h <11	11 ≤ h < 17	17 ≤ h < 23	23 ≤ h < 35	35 ≤ h ≤50	TDD
< 20	4,0	2,0	1,5	0,6	0,3	5,0
20 < 50	7,0	3,5	2,5	1,0	0,5	8,0
50 < 100	10,0	4,5	4,0	1,5	0,7	12,0
100 < 1000	12,0	5,5	5,0	2,0	1,0	15,0
> 1000	15,0	7,0	6,0	2,5	1,4	20,0

Table 17: Current distortion limits for systems rated 120 V through 69 kV

Even harmonics are limited to 25% of the odd harmonic limits above.

Isc = maximum short-circuit current at PCC
I_L = maximum demand load current (fundamental frequency component) at the PCC under normal load operating conditions

UL 1741

The UL 1741 makes a regulatory difference regarding harmonic distortion limits between stand-alone inverters and utility-interactive,

For a stand-alone inverter, the total rms of the harmonic voltages, excluding the fundamental delivered, shall not exceed 30 percent of the fundamental rms output voltage rating, The rms voltage in any single harmonic shall not exceed 15 percent of the nominal fundamental rms output voltage rating,

For a utility-interactive inverter, the total harmonic distortion (THD) of the rms current, shall be less than 5 percent of the fundamental at full load, Individual odd harmonics shall not exceed the limits specified in Table 18 nor the even the Table 19.

Odd harmonics	Distortion limit (percent)
3rd through 9th	4,0
11th through 15th	2,0
17th through 21st	1,5
23rd through 33rd	0,6
Above the 33rd	0,3

Table 18: RMS current distortion limits for individual odd harmonics UL 1741

Even harmonics	Distortion limit (percent)
2nd through 1Oth	1,0
12th through 16th	0,5
1Bth through 22nd	0,375
24th through 34th	0,15
Above the 36th	0,075

Table 19: RMS current distortion limits for individual even harmonics UL 1741

UNE EN 206007

Different standard apply depending on the nominal current of the inverter

- I < 16 A →UNE-EN 61000-3-2, which limits are depicted in Table 11.
- 16 A < I < 75 A → UNE-EN 61000-3-12, which was not possible to obtain.
- I > 75 A → UNE-21000-3-3 IN, which was not possible to obtain.

UNE EN 50438

The standard refers to the UNE-EN 6100-3-2, "Electromagnetic compatibility (EMC) - Part 3-2: Limits - Limits for harmonic current emissions (equipment input current ≤ 16 A per phase)", which limits are depicted in Table 11.

VDE-AR-N 41052011-08

Different standards apply depending on the nominal current of the inverter:

- Rated currents below 16A: UNE-EN 61000-3-2, which limits are depicted in Table 11.
- Rated currents above 16 A and up to and including 75 A per conductor: the limit values of DIN EN 61000-3-12 (VDE 0838-12).
- For rated currents above 75 A, or if the values stated in UNE-EN 61000-3-2 and DIN EN 61000-3-12 are not complied with, Table 20 applies. This table shows permissible harmonic currents related to the network short-circuit power S_{sc} that may be supplied in a network connection point.
  For the correct use of the table, the maximum permissible harmonic currents $I_{max-harmonic}$ of a power generation system are calculated from the related harmonic currents i_{table} of Table 20 times the network short-circuit power at the PCC (minus the power generation system's share in short-circuit power):

$$I_{hmax} = i_{table} * S_{sc} \tag{1}$$

Ordinal number ν ,μ	Permissible related harmonic current i_{table} in $(^{A}/_{MVA})$
3	3
5	1,5
7	1
9	0,7
11	0,5
13	0,4
17	0,3
19	0,25
23	0,2
25 <ν < 40	0,15 – 25/ν
Even	1,5/ ν
μ < 40	1,5/ ν
42 <ν, μ < 178	4,5/ν

Table 20: Limits for even Harmonic current distortion VDE-AR-N 41052011-08

BDEW

As for the German VDE, the harmonic permissible current are also calculated depending on the system, by means of the Equation (1), But the standard sets out different values for i_{table}, which are classified depending on the PCC voltage, as it is shown in Table 21.

Ordinal number μ , v	Admissible, related harmonic current i_{table}, in A/MVA		
	10 kV network	20 kV network	30 kV network
5	0,058	0,029	0,019
7	0,082	0,041	0,027
11	0,052	0,026	0,017
13	0,038	0,019	0,013
17	0,022	0,011	0,07
19	0,018	0,009	0,006
23	0,012	0,006	0,004
25	0,010	0,005	0,003
25 < v < 40	0,01 * 25/v	0,005 * 25/v	0,003 * 25/v
even- numbered	0,06/v	0,03/v	0,02/v
μ < 40	0,06/μ	0,03/μ	0,02/μ
μ , v > 40	0,18/ μ	0,09/μ	0,06/μ

Table 21: Limits for even Harmonic current distortion BDEW

3.2.5.2. Analysis

For a better understanding and a global view, we could separate regulations according to the methodology to treat harmonics into three groups:

- Harmonic Voltage Distortion: The standards that only regulate harmonic voltage penetration.
- Harmonic Current Distortion: The standards that only regulate harmonic current penetration.
- Customizable: The standards that set out harmonic current limits which must be calculated for each installation once the network short circuit power is known.

The most permissive regulation with harmonics is the India Gazette, which refers to IEEE 519, and it could be explained as from all the countries studied, India is probably the one which deals with higher harmonics in the system, as their grid network is not still enough developed, so more relaxed restrictions shall be placed. For the rest of the cases, it is very common to find a THD of 5%, and permissible odd harmonics set to be 75% more strict than for the even.

It is also important to mention that most of the European Standards delegate on the UNE EN 61000 3-2 for harmonic limitation, which is a specific standard for the matter.

3.2.6. Phase balance

Under ideal conditions, each phase should be 120º apart and peak magnitudes should be equal, but recurrently, waveforms present phase shifts and uneven phase magnitudes.

The main causes of phase unbalance in DG systems are [54]:

- Mechanical problems in the stator windings and rotor. Degradation of the components is due to its continuous operation, and it is usually different in each phase, creating unbalance in phase angle and magnitude.
- Current leakage in the coils around the stator. This leakage can provide floating earth at times, translating into fluctuations.

Phase unbalance has negative effects in the grid and in the motors connected to it:

- ➢ It promotes losses. Unbalance forces more current to go through the common return line, implying a greater (I squared R) power loss in the return impedance. Under a 1% of unbalance the effect is almost negligible. Over 1%, the losses increase linearly and a 4% of unbalance creates losses of 20% of the current [54].
- ➢ Reduction of electrical equipment efficiency. For a motor, a 5% of unbalance in the input power, results in capacity reduction of 25% [54].
- ➢ Other effects include increase of harmonics and creation of negative phase sequence current that can lead to faults and permanent damage to the equipment.

3.2.6.1. Comparative Regulation Study

Only 5 of the following 11 deals with them, as the Table 22 shows. The phase balance issue is generally treated setting a maximum percentage of phase unbalance.

Standard	Considerations
G59	The G59 classifies the DG systems into two groups to regulate the unbalance: - Nominal Voltage < 33 kw à Voltage unbalance at PCC less than 1.3% - Nominal Voltage 33-132 kw à Voltage unbalance at PCC less than 1% It also states that voltage unbalance cannot exceed 2% for any system over more than a minute period.
G83 (I)	There is no requirement to balance phases on installations below or equal to 16A per phase
GB/T 19964-2012	The applicable document is GB/T 15543.
IEC 61727	Not considered
IEEE 1547	No limits stated, although it mentions 2,5% to 3 % voltage unbalance a risk for the system
Official India gazette	Not considered
UL 1741	Not considered
UNE EN 206007	Not considered
UNE EN 50438	Not considered
VDE-AR-N 41052011-08	A maximun difference of 4.6 kVA per phase shall not be exceeded
BDEW	Not considered

Table 22: Analysis of Phase balance restrictions

(I) For multiple installations, balancing the will need to be considered by the DNO

3.2.6.2. Analysis

The fact that phase balance is not widely regarded is mainly because most of Table 2 standards refer to LV/MV, where the unbalance effects are not as critical as for HV. That is why G59 accurately addresses the topic, as this standard deals with HV installations.

The data obtained follows the line of what has been previously explained about phase balance, and any recommendation allows higher than 4% unbalances.

3.2.7. Direct Current injection

Electronic equipment that converts Direct Current (DC) into AC, as inverters used in PV systems or back to back converters used for example, in wind turbines, introduce different amounts of DC into the grid. There are further studies [55] , that analyze the amount of DC current injected by each type of inverter and conclude that such electronic equipment always introduce some kind of DC disturbance in the AC system. These is as the electronics of these devices transform the AC sinusoidal waves from the DC signal, and imperfections in the new waveform arise under these processes. On top of it, when the DG system is composed by several electronic equipment, as Figure 13 shows, the DC output might be enlarged.

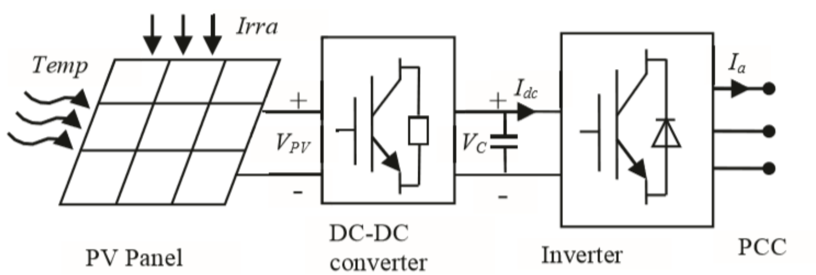


Figure 13: Typical PV installation scheme [56]

However, amount of DC injected by DG systems usually has a negligible impact over grid customers, but it can have a considerable impact in upstream distribution transformers. It can shift transformers operating point and cause saturation. A saturated transformer can lead to high primary current peaks, which can trip the input fuse.

3.2.7.1. Comparative Regulation Study

DC injection is a common issue for DG systems, therefore, it is a topic typically addressed by the standards. A total of 14 where analyzed, as Table 23 depicts. The method of regulating such parameters is stating a percentage on the DC over the total current that the generator shall provide.

Standard	Considerations
G59	0,25%
G83 (I) (II) (III) (IV)	0,25%
GB/T 19964-2012	Not considered
IEC 61727	1%
IEEE 1547	0,5%
Official India gazette	0,5%
UL 1741	0,5%
UNE EN 206007	0,5%
UNE EN 50438	The generating unit shall not inject a direct current
VDE-AR-N 41052011-08	Not considered
BDEW	Not considered
AS 4777.2	5 mA
JEAC 9701-2012	1%
IEEE 929-2000	0,5%

Table 23: Analysis of DC injection restrictions

(I) Where a DG is designed to be installed singly in an installation, DC injection limit can be a maximum value of 20mA for sub 2Kw.

(II) A 2kW single phase Inverter has a current output of 8.7A so DC limit is 21.75mA

(III) A 10kW three phase Inverter has a current output of 14.5A per phase which is equivalent to a total of 43.5A at 230V so DC limit is

(IV) DC requirement can also be satisfied by installing an isolating transformer between the inverter and the PCC.

3.2.7.2. Analysis

Three different percentages are set, where 1% is the higher allowable DC injection, permitted by the Japanese standard and the IEC 61727, and 0,25% is the strictest, used by the English standards.

3.2.8. Flickers and fluctuations

By its own nature, the grid undergoes fluctuations every second, exactly 50 times in Europe and 60 in the USA. However, these fluctuations are considered flickers, or regulated under different standards. It is the fluctuations coming from impurities in the power supply which are regulated and can be harmful for electrical equipment and for humans.

Flicker used to be measured and legislated according to the Figure 14. The voltage fluctuations were measured against the time during the testing of the devices, and the table could determine whether the flicker level was harmful or not, and in which level.

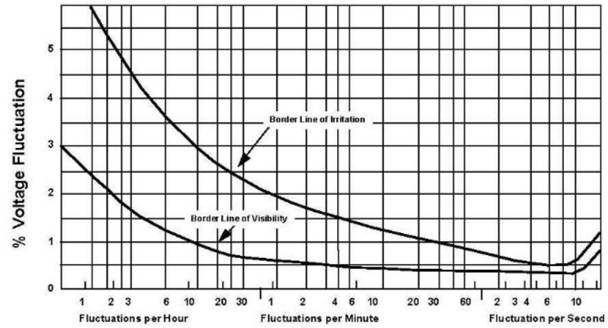


Figure 14: Previous flicker detection methodology [57]

However, as technology evolved, a new element, called the flicker meter was developed, which can measure the voltage fluctuations and provide two different values, the P_{st} and the P_{lt}. P_{st} refers at the short-term flicker (commonly taking into account a 10 minutes time span), and the P_{lt} standing for long term flicker (commonly taking into account a 120 minutes time span) [57].

PV systems are a major contributor to flickers in the grid. This is due to the variation of solar radiation that the panels receive along the day. This factor is also applicable to wind turbines, as the amount of wind varies within minutes.

But there is another great flicker contributor, inverters. When the transform the steady DC into the AC waveform, the impurities mentioned before are created. However, one inverter producing power from solar panels will not normally produce enough flicker to even reach the level of perception. Several inverters connected to the electric feeder will increase flicker, but it will take an ordinal multiple of the load on the feeder before this becomes a flicker issue.

The problem unexpectedly arises with the clouds and large PV systems, with multiple inverters. Large-fast moving cloud can reduce drastically the solar irradiance of many panels at the same time and uncover many others. This will lead to several inverters receiving fluctuating inputs and is the major source of flicker in DG systems.

The health effects of flicker can be divided into those that are the immediate result of a few seconds exposure, such as epileptic seizures, and those that are the less obvious result of long-term exposure, such as malaise, headaches and impaired visual performance. The former are associated with visible flicker, typically within the range between 3 to 70 Hz, and the latter with invisible modulation of light at frequencies above those at which flicker is perceptible (invisible flicker). Human biological effects are a function of flicker frequency, modulation depth, brightness, lighting application, and several other factors.

3.2.8.1. Comparative Regulation Study

Voltage fluctuations are measured through P_{lt} and P_{st}, which always account for the upper permissible limit. Therefore, Table 24 depict the maximum value these parameters can have according to the standards. There is an additional parameter that some standards take into consideration, the D_{max}, which is the maximum allowed voltage change during the fluctuation measurement.

Standard	Conditions	P_{st}	P_{lt}	D_{max}
G59(I)	V < 132 Kv	1	0,8	
	V > 132 Kv	0,8	0,6	
G83(II)		1	0,65	4%
GB/T 19964-2012(III)	V < 110 Kv	NA	1	3%
	V > 110 Kv	NA	0,8	
IEC 61727(III)		1	0,65	4%-7%
IEEE 1547(IV)	PCC at secondary distribution voltage	1	NA	
	PCC at primary distribution voltage	0,9	NA	
Official India gazette (III)		1	0,65	4%-7%
UL 1741		NA	NA	
UNE EN 206007(III)		1	0,65	4%-7%
UNE EN 50438(III)		1	0,65	4%-7%
VDE-AR-N 41052011-08(III)	Rated currents of up to and including 16 A	1	0,65	4%-7%
	Rated currents above 16 A and up to and including 75 A	NA	NA	
	Rated current above 75 A	NA	0,5	
BDEW		NA	0,46	

Table 24: Analysis of flicker restrictions

(I) Harmonics limits are considered in EREC P28

(II) Harmonics limits are considered in EN 61000-3-3

(III) Harmonics limits are considered in GB/T 12326

(IV) Harmonics limits are considered in EN 61000-3-3

(V) DR units will meet the IEC requirement if the power variations from the unit (ΔS) compared with the available short-circuit capacity (SSC) of the area EPS at the PCC are within the limits described in Table []

3.2.8.2. Analysis

From the data showed on Table 24, it might seem that some cohesion exists between the regulations, but this is because for this case, many of them refer for flicker limitation to a common recommendation, the EN 61000-3-3. So, taking this into account, it can be stated that the way flicker is regulated varies greatly within countries and regulations. For example, some regulations only consider long term flicker limits, see Chinese standard, while others do the opposite, as the Germans.

3.2.9. Islanding

Islanding is a critical and unsafe condition in which a distributed generator continues to supply power to the grid although the electric utility is down. In the analyzed standards, it is important to differentiate between islanding protection, and islanding mode.

Islanding is created after a power outage or blackout, which is a loss of the electric power supplied by the grid to a particular area. The causes of the blackout can be damages in the lines, transformers, or any other piece of the grid equipment.

Islanding causes many problems [58], some of which are listed below:

1. **Safety Concern:** Safety is the main concern, as the grid may still be powered in the event of a power outage which may confuse the utility workers and expose them to hazards such as shocks.

2. **Damage to customer's appliances:** Due to islanding and distributed generation, there may a bi-directional flow of electricity. This may cause severe damage to electrical equipment, appliances and devices. Some devices are more sensitive to voltage fluctuations than others and should always be equipped with surge protectors.
3. **Inverter damage:** In the case of large solar systems, several inverters are installed with the distributed generators. islanding could cause problems in proper functioning of the inverters.

Regarding islanding conditions in the regulations, some only specify the disconnection time after island is detected, and some others go further, determining the protection methods to be used or the detection system of the issue.

There are many ways to detect islanding, and they can be categorized into active and passive detection methods [59] :

<u>Passive islanding detection</u>

Passive detection methods make use of transients in the electricity (such as voltage, current, frequency, etc.) for detection. This method consists on a constant monitoring of network parameters that greatly vary under island conditions. Therefore, the island detection depends on the set threshold that determines islanding. Passive techniques are fast, and they don't introduce disturbance in the system as the active method, but they have a large non-detectable zone (NDZ) where they fail to detect the islanding condition. There is another critical point to be considered when passive islanding detection methods are considered, and frequency support is permitted under the same regulation. The problem is that frequency support has reportedly originated stable unintentional islanded systems. After fault in the system occurs, the frequency support will instantaneously start working, and in cases where the load is not very high, the DG system can stabilize the fault. However, if a delay time in the frequency response is set, in case the frequency drop was due to a fault, the frequency will fall out the limits imposed in Table 3, triggering automatic disconnection.

Regarding passive detection methods considered in the standards, the most common ones are:

- ROCOF: Standing for Rate Of Change Of Frequency based on that the rate of change of frequency, $({}^{df}/_{dt})$,is be very high when the DG is islanded. This method's challenge is to determine a valid rate that will be used as threshold.
- Vector Shift: The Vector Shift protection algorithm is based on voltage angle measurements performed on all three phase voltages. A measurement is taken from each of the 3 phase voltages after every half-cycle and the decision is made after a full cycle.
- Phase voltage monitoring: This method consists on measuring each of the phases searching for abnormalities, and if at least one line conductor voltage falls below the limit values that have been set in a %, automatic disconnection shall follow.

Active islanding detection

Under active detection, the island can be detected even under the perfect match of generation and load, which is not possible in case of the passive detection schemes. Active methods directly interact with the power system operation by introducing perturbations. The idea of an active detection method is that this small perturbation will result in a significant change in system parameters when the DG is islanded, whereas the change will be negligible when the DG is connected to the grid

3.2.9.1. Comparative Regulation Study

Islanding is considered by most of the DG systems standards, a total of 19 have been analyzed, and the summaries and a comparison table are shown below. Some regulations consider both, unintentional islanding, which is regarded as LoM (loss of mains). Due to variability of islanding regulation, it was not possible to summarize all the data in a table, so some standards will be summarized, while others are included in Table 27.

G59

Loss of Mains Protection

A LoM protection of RoCoF or vector shift type will generally be appropriate for Small Power Stations, but this type of LoM protection must not be installed for Power Stations at or above 50 MW.

Applicability	Asynchronous	Synchronous	Minimum relay operate time
Generating Plant Commissioned before 01/08/14	1Hz/s	0.5Hz/s	0.5s
Generating Plant commissioned between 01/08/14 and 31/07/16 inclusive	1Hz/s	0.5Hz/s	0.5s
Generating Plant commissioned on or after 01/08/16	1Hz/s	1Hz/s	0.5s
Vector Shift (where used)	6°	6°	Not specified

Table 25: Loss of Mains possible configurations G59

Island Mode

For a DG system to operate in island mode, it is stated that the separated grid shall comply all statutory regulations, and a contractual agreement must exist between the DNO and Generator. In this agreement, the following matters shall be present:

- Load flows, voltage regulation, frequency regulation, voltage unbalance, voltage flicker and harmonic voltage distortion.
- Earthing arrangements.
- Short circuit currents and the adequacy of protection arrangements.
- System Stability.
- Resynchronization to the Total System.

- Safety of personnel.

Once the DG system is operating in island mode, and have fulfilled all the previous requirement, a confirmation of its current working state has to be transmitted to the Generating Units protection and control schemes.

G83

Loss of Mains Protection

Regarding the islanding protection, passive methods are allowed, with the parameters from Table 26. Other forms of Loss of Mains techniques may be utilized but the aggregate of the protection operating time, disconnection device operating time and trip delay setting shall not exceed 1,0 s. Under- and over-frequency protection is required in addition to LoM protection, not instead of.
Active methods for detecting LoM which inject current pulses into the distribution network are not accepted in Great Britain.

Method	Threshold	Minimum relay operate time
Loss of Mains (Vector Shift) (I)	12º	0,0s
Loss of Mains (RoCoF) (I)	0,2 Hz/s	0,0s

Table 26: Loss of Mains possible configurations G83

(I) The protection settings can be increased to 5,0 s for those micro-generator units that can withstand being energised from a source that is 180° out of phase with the micro-generator output

Under- and over-frequency protection is required in addition to LoM protection, not instead of, and it is stated that for the avoidance of doubt voltage and frequency excursions lasting less than the trip delay setting shall not result in disconnection.

Island Mode

Those installations that operate in parallel with the DSO's Distribution System for short periods (ie less than 5 minutes) or as an islanded installation or section of network are considered to be out of scope.

IEEE 1547

Loss of Mains Protection

DG interconnection system shall detect the island and cease to energize within two seconds. For the protection settings, it is mentioned that reactive or active schemes shall be used, but the specific setting are not defined.

Island Mode

Adressed in IEEE P1547.4, which it was not possible to obtain access.

UNE EN 50438

Loss of Mains Protection

This standard identifies some approaches to combine the interests of overall system security and the detection of unintentional islanding. As the standard does allow frequency support, the issue of a stable unintentional island creation shall be dealt with:

• An intentional delay of 2 seconds in the activation of the response to frequency deviation with the time needed for the island detection to operate.

• The possible activation of a narrow frequency window (e.g. 49,8 Hz – 50,2 Hz) in the interface protection in case of a local event.

Amidst other possibilities, some are listed here:

- other methods of islanding detection not based on frequency including transfer trip;
- voltage supervised reclosing;
- remote control of generators or loads, e.g. during maintenance works;
- multiphase earthing of the island.

VDE-AR-N 41052011-08

Loss of Mains Protection

The guide defines the possible methods for island detection two methods can be implemented:

- Active method, i.e frequency shift method.
- Passive method by means of three phase voltage monitoring, which is only possible for power generation systems without inverters or for single-phase power generation units with inverters. The limits are of 80 % and 115 %, and if the voltage falls from the range between both values, automatic disconnection shall follow within 0,2 seconds.

As a general requirement, and if not other more strict time is defined, once island condition is detected, the DG system shall cease to energize within 5 seconds.

BDEW

Loss of Mains Protection

It is stated that in order to protect the DG systems and other customer facilities from events as islanding, protective disconnection devices shall exist to disconnect the system. But the specific type of protection, and further requirements are left as responsibility of the DNO, as the Standard considers MV and HV which are likely to be major suppliers to the network.

OTHER REGULATIONS

Standard	Method	Max Clearance time (s)	Minimum clearance time (s)	Threshold
GB/T 19964-2012				
IEC 61727		2		
Official India gazette		2		
UNE EN 206007 (I) (II)		2		
UL 1741		2		
Austria ÖVE/ÖNORM E 8001-4-712 (III)		5		
Belgium CE10/11(IV)				
Cyprus		0,5		0,6 Hz/s
Denmark(V)		0,2	0,1	2,5 Hz/s
Finland		5		2 Hz/s
Ireland DTIS-230206-BRL(VI)	ROCOF		0.5	0,4 Hz/s
	Vector Shift		0.5	6°
Latvia Elektroenerģijas tirgus likums, 05.05.2005 (Electricity Market Law) (VI)	ROCOF		0.5	0,4 Hz/s
	Vector Shift		0.5	8º
Slovenia Uradni list RS (Official Gazzette of the Republic of Slovenia) No. 41/2011	LoM is not required			
Sweden	Loss of Mains	0.15		

Table 27 Analysis of Islanding restriction and conditions

(I) UNE 206006 IN applies

(II) For inverters placed in installations that already incorporate anti islanding protection, no further requisites are demanded

(III) LoM protection and test procedures have to be conform with ÖVE/ÖNORM E 8001-4-712.

(IV) LoM is defined in DIN V VDE V 0126-1-1

(V) The use of phase shift relay as LoM detection is not allowed.

(VI) The only Loss of Main detection methods allowed are passive, active methods are explicitly not permited

3.2.9.2. Analysis

Regarding DG systems operating is Islanded Mode, specific standards shall be considered so as to provide an analysis, as the studied ones normally do not refer to this situation, or they only provide with the outline of how to proceed.

Unintentional Island protection, on the other hand, is widely considered, although unalike results have been obtained. Active protection methods are only considered in VDE-AR-N 41052011-08, and the G83 states that they are forbidden in Great Britain. But passive detection is considered in most of them, with varied parameters and methods that can be implemented. From the results, it has been observed that ROCOF and Vector Shift are the most common. For vector shift, the allowable parameters range from 6º to 12º, and ROCOF varies between 0,2 Hz/s to as much as 2,5Hz/s.

The disconnection time is also provided, and in many cases the standards does not specified the island detection method but does state the maximum or minimum clearing time.

3.2.10. Short Circuit

A short circuit is simply a low resistance connection between the two conductors supplying electrical power to any circuit [60]. A disproportional amount current will flow through this low impedance connection, also called "short".

The connection of DG systems to the grid usually implicates an increase in the level of short circuit currents. This is because the short circuit current of the generator adds up to the already existing current at the PCC.

There are several harmful effects associate to the excessive current generated by the short circuit:

- The increase of current has a direct effect decreasing the voltage, and as the DG systems are close to the loads, the voltage in the load can be drastically reduced, causing major problems in the appliances or machinery.
- The decrease in voltage can make other generator to disconnect.
- Heavy currents created in the short lead to abnormal increases on the temperature of the conductor, which can result in a fire or explosion.

Short circuit regulation has been treated since long time ago, and DG standards usually refer to other approved ones for the matter.

3.2.10.1. Comparative Regulation Study

For the Short Circuit protection, 12 standards have been reviewed, with scarce results that are shown in Table 28.

Standard	Considerations
G59	EREC G74
G83	Not considered
GB/T 19964-2012	Not considered
IEC 61727	IEC 60364-7-712
IEEE 1547	Large current faults: Shall be cleared within 0.1 seconds. Low current faults: Clearing time of 5 to 10 seconds or longer
Official India gazette	Not considered
UL 1741	Not considered
UNE EN 206007	UNE-EN 62109-2
UNE EN 50438	HD 60364
VDE-AR-N 41052011-08	Synchronous generators: 8 times the rated current. Asynchronous generators: 6 times the rated current. Generators with inverters: 1 time the rated current.
BDEW	Short Circuit Current at the transfer point shall be provided.
Engineering Recommendation P25	For single-phase 230 V 19.6 kA For three-phase 400 V 25.9 kA

Table 28: Analysis of Short Circuit restrictions

3.2.10.2. Analysis

The Short Circuit protection has been the point where the most unalike limits are stated. For the few regulations that treat the issue, each of them deals with it in a different way. There are also other DG standards that refer to specialized short circuit recommendations, but it was not possible to obtain license for the ones that appear in Table 28.

4. Study Case: DG in San Cristobal Island

4.1. Introduction

Once DG has been explained, the technical requirements have been analyzed and compared among different standards and regulations, the paper will focus on the real implementation of all the aspects considered. To do so, the real case of an island supplied by DG systems is going to be studied, and in parallel, the two other challenges defined in point 2.4.2 that the DG will face in the future will be addressed. This study will be performed simulating different configurations of DG supply in the island.

4.2. General and specific context of the Island

4.2.1. General context

The chosen Island for the study is San Cristobal, which lays 970 km of the Western Ecuadorian Coast. It belongs to the Galapagos Archipelago, located at the Eastern side of it and contains the Galagos capital, Puerto Baquerizo. The Archipelago has become a Natural Park, Marine Reserve, the first UNESCO World Heritage in 1979 and Biosphere Reserve.

Figure 15: Galapagos Archipelago [61]

It is the Natural wonders the Archipelago hosts what boosted tourism since the early 80's, which combined with the exponential growth of the Native population, deteriorated the Natural reserve. The point of deterioration was so severe, that the UNESCO placed the Galapagos Islands on the list of Endangered World Heritage sites. However, in 2010, an ecotourism plan was released in collaboration with more than 100 stakeholders, private and public [62]. This new plan has reverted the situation to the point that in 2012 UNESCO returned previous status to the Islands.

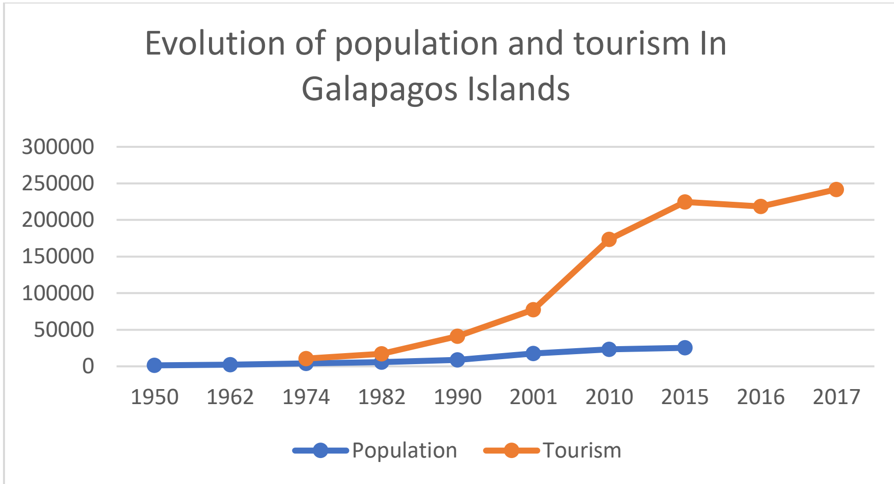


Figure 16: Population and visitors evolution in Galapagos

The Ecotourism transition had two main impacts on the Archipelago relevant for the Energetic Study. On the one hand, several regulative changes gave the Government legal authority for the touristic inflow, as it can be appreciated for the last years in Figure 16. The other relevant outcome has been the commitment for an increase in renewable energy supply on each of the islands [62]. The transition towards a sustainable had already began when the plan was finally agreed, as it was in 2007, when the first wind farm began to operate in San Cristobal. The trend has been continued by several more renewable energies projects. Table 29 shows the current generation and implementation of each of the inhabited islands in the Archipelago.

Island	Thermal(kW)	WindkW)	Solar PV(kW)	Batteries	Generating Capacity (kW)
San Cristóbal	5050	2400	12,5		7462,5
Santa Cruz	14950	2250	1567	Pb-Acid:500kW; 4,032kWh Li-ion:500kW; 268kWh	18767
Isabela	2640				2640
Floreana	283		20,9	Pb-Acid:36kW; 96kWh	303,9

Table 29: Installed capacity in Galapagos Archipelago [63]

4.2.1. San Cristobal

Figure 17: San Cristobal Island [64]

Regarding San Cristobal, the population and tourism tendency has been in line with the rerst of the archipelago. The population in 2015 was 7199 inhabitants, and the growth was slowed after 2010 as well, shown in Figure 18.

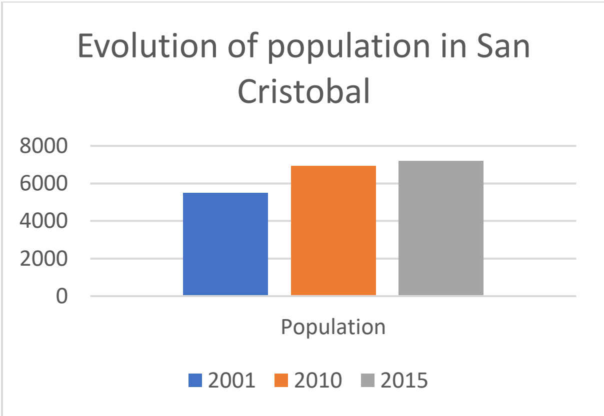


Figure 18 Evolution of San Crsitobal population

From the electricity supply point of view, in order to support the growing tourism and population, important expansions in the installed capacity were made between 2009 to 2013. The generating units installed in the island are shown Table 18. The data was provided by ELECGALAPAGOS S.A.

	Manufacturer	Model	Installation Year	Units	Nominal Power (kW)	Total Power (kW)
Diesel Generators	Caterpillar	3512 DITA	1990	3	650	1950
	Perkins	PS1386E	2009	1	1000	1000
	MTU	1.6V 2000 G85	2013	1	1000	1000
	Caterpillar	3516	2011	1	1100	1100
Wind turbines	MADE	AE59	Not Provided	3	800	2400
PV system	Not Provided	Not Provided	Not Provided	2	6.25	12.5
TOTAL POWER						7462.5

Table 30: Installed capacity in San Cristobal [63]

The island is supplied by Diesel generators Generators, all of them located next to the city, the three wind turbines placed in “Cerro el Tropezón”, and a small capacity solar park located next to the city.

The electrical Grid runs in LV and MV, and the loads are mainly concentrated in the city. Annex C contains the official blueprints of San Cristóbal Electric Grid architecture, provided by ELECGALAPAGOS S.A, the Electrical company which owns the concession to operate in the islands.

The loads and generation are connected by means of an 13,2 KV line, which combines a total of 9km of aerial line and 3km of underground, to protect the national Park in several locations. It is important to point out that the island does not have the conventional transmission line, but the distribution line functions as well as transmission, which implies that all the island is energized by Distributed Generation.

4.3 Software

The chosen software to perform the economic feasibility simulation and the reserve and planning study is the Homer Pro, which stands for Hybrid Optimization Model for Electric Renewable. The objective was to study the implementation of DG systems in a real case, and shed light on the two other challenges that the deployment of these technology brings. Homer Pro was perfectly suitable for the task, as it generates the energetic balance and the economic turnout of the different simulations the user defines. On top of this, the software is also able to optimize and suggest different results depending on the entered constraints.

The software performs a system simulation for each of the 8760 hours a year has, by comparing the possible generation of the system with the inputted demand. In case such a detailed in demand is not available, the user can introduce the daily or monthly data, but the simulation would lack precision. After this, each of the generating units in the system shall be introduced, with all the possible associated parameters, from the cost of operation, the chemical attributes of the used fuel, or the monthly solar irradiance.

Once all these data is inputted, as it will be detailed in the next point, some of Homer Pro unique features can be modified, as the optimization capacity and the sensitivity analysis.

- Optimization: For most of the parameters, as generating units, or type of fuel, the user is able to select optimization mode, so that the software directly chooses which will be the most economical solution. For example, Homer Pro will detect how many diesel generators should be placed in the system, or how many should be removed.

- Sensitivity Analysis: Some variables can be considered sensible inputs and thus Homer repeats the simulation process for each of them. This is useful in case the user has a defined range of possible configurations and wants to select the best.

After all the parameters are defined, Homer Pro will run all possible simulations, which could easily account for more than 10000 configurations, and then sorts the feasible ones by means of COE and NPV, and provides the data for the following economic factors:

- **COE**: The levelized cost of energy (COE), which is the average cost per kWh of useful electrical energy produced by the system. The mathematical formula is:

$$COE = \frac{C_{ann,tot} - c_{boiler} * H_{served}}{E_{served}} \tag{2}$$

Where:

$C_{ann,tot}$ = total annualized cost of the system [$/yr]

c_{boiler} = total annualized cost of the system [$/yr]

H_{served} = total thermal load served [kWh/yr]

E_{served} = total electrical load served [kWh/yr]

- **NPV**: The net present value (NPV) of a Component, which is the present value of all the costs of installing and operating the Component over the project lifetime, minus the present value of all the revenues that it earns over the project lifetime.

- **General Costs**
  - By Component: The cost of each component in the system will be shown, which comprises from the invested capital on its purchase, to the operating cost or possible replacement during the simulated years.
  - By type of Cost: The cost will be splited between:
    - Capital: The total amount that was invested in the purchase of the equipment.
    - Operating Cost: This field considers the cost maintenance cost of the equipment.
    - Replacement: Some components shall be replaced during the simulated years. The replacement cost is around the 80% of the initial cost, as the installations are already prepared, and they do not need to be rebuilt.

- ❖ Salvage: Homer considers the value of the equipment at the end of the project life, and substarcts it to the cost, so this parameter is not a cost, but a return.
- ❖ Fuel: Cost of used fuel.

Other relevant self-explanatory characteristics that will be seen in the analysis of the scenarios are also displayed after the simulation.

Each of the results can then be accessed for further details, with an hourly diagram of the system's operation, including demand, battery charge at each hour, and operation capacity of each generating unit, as it can be seen in Figure 39.

4.4 Input Data

For the sake of clarity and collaboration with future analysis of the islands, the most relevant input data regarding the demand, generating units and natural resources affecting renewable energy will be displayed and referenced.

4.4.1 Demand Data

The real electrical demand data used for the project was provided by ELECGALAPAGOS S.A, and is made up of the monthly values among 2012 and 2015, and the hourly values for 2015.

The required demand to be introduced in Homer Pro had to be the daily projection up to 2025, as it was explained in Section 1.3, Structure. As the available data is not forecasted, nor hourly, two steps were taken to transform the available data into useful inputs

<u>Step 1: Monthly Demand Projection</u>

1. Computation of centered moving average from the 2012-2015 monthly demand data in order to obtain the possible trend, Figure 19.
2. The demand and the trend are related by means of seasonal coefficients, which are then obtained for each month the four years. After that, the average of the coefficients of each month for each of the years was calculated and shown in Table 31.
3. The demand real data is divided by the average seasonality coefficients, so that the cyclical monthly pattern was eliminated. The data reduced from the monthly variations was then ready to prove whether there was a recognizable trend amid the years. The smoothed data is shown in Figure 19, were it can be appreciated the difference between a de-seasonalized data and the real demand. It can also be observed, that the data follows a linear trend.
4. The Simple regression line was calculated from the de-seasonalized data, confirming mathematically the existence of a trend behind all the cyclical monthly fluctuations, as the P-value was significantly different than 0, in Figure 21. It was obtained using Excel data Analysis Add-In, where the coefficients for the function are obtained.

5. With the Simple regression line slope and intercept the real trend was computed, and the last step was to multiply the values of the trend for each month by the average seasonal coefficients from Table 31, obtaining the forecast equation plotted in Figure 20. In the figure the forecasted and the real demand are plotted together to demonstrate the correlation between both and verifying the forecasted data.

After the trend function was obtained, it was possible to compute the forecasted demand for any future period.

<u>Step 2: Break down of monthly data into hourly</u>

For the hourly demand forecast, the hourly data provided by ELECGALAPAGOS from year 2015 was used. The average hourly demand was computed for each month, and the real hourly demand was divided between it, obtaining an hourly coefficient. Monthly demand values forecasted, the average hourly demand per month was calculated and then multiplied by each hourly coefficient, obtaining the hourly demand.

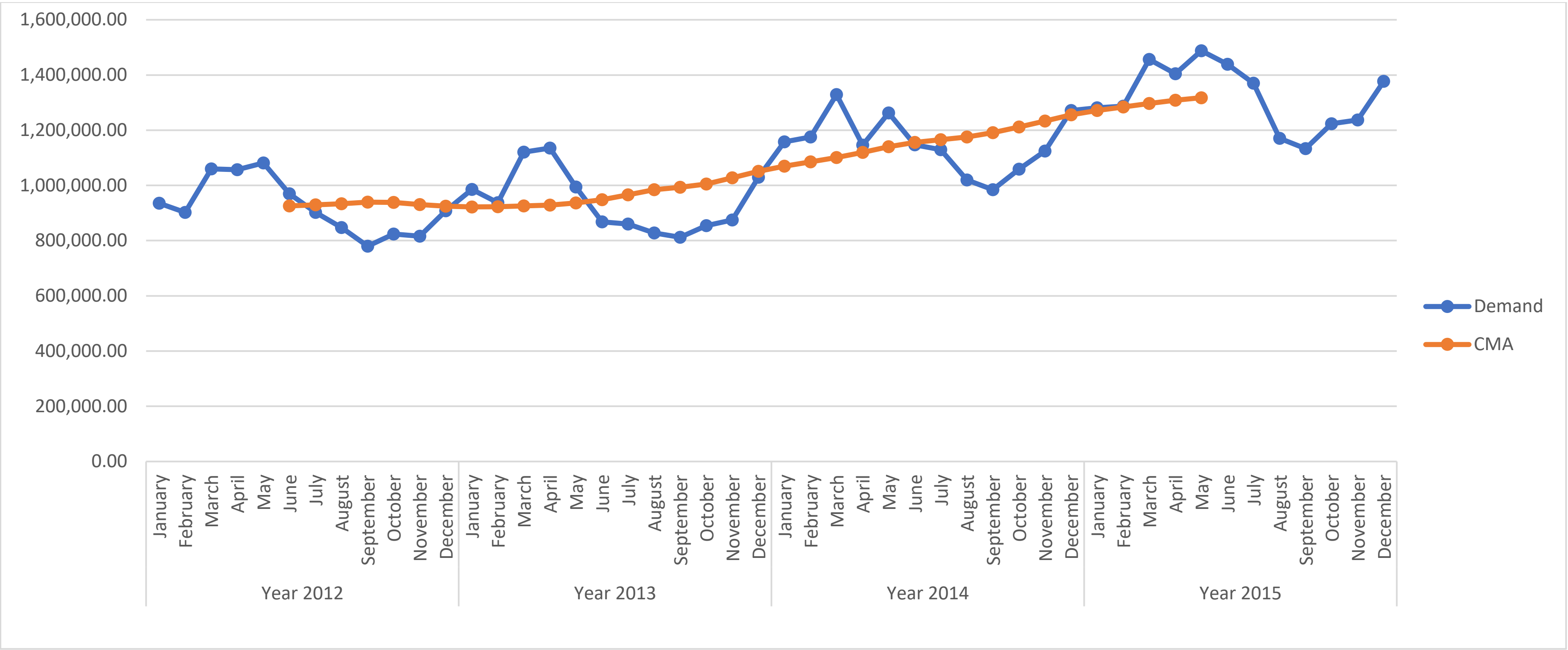


Figure 19: San Cristobal Electric demand evolution

Average seasonal coefficient			
January	1,05262359	July	0,943424932
February	1,033778035	August	0,872492834
March	1,180310796	September	0,824700401
April	1,105867617	October	0,867029424
May	1,0990678	November	0,879824165
June	0,985096316	December	0,991383031

Table 31: average seasonal deviation coefficients

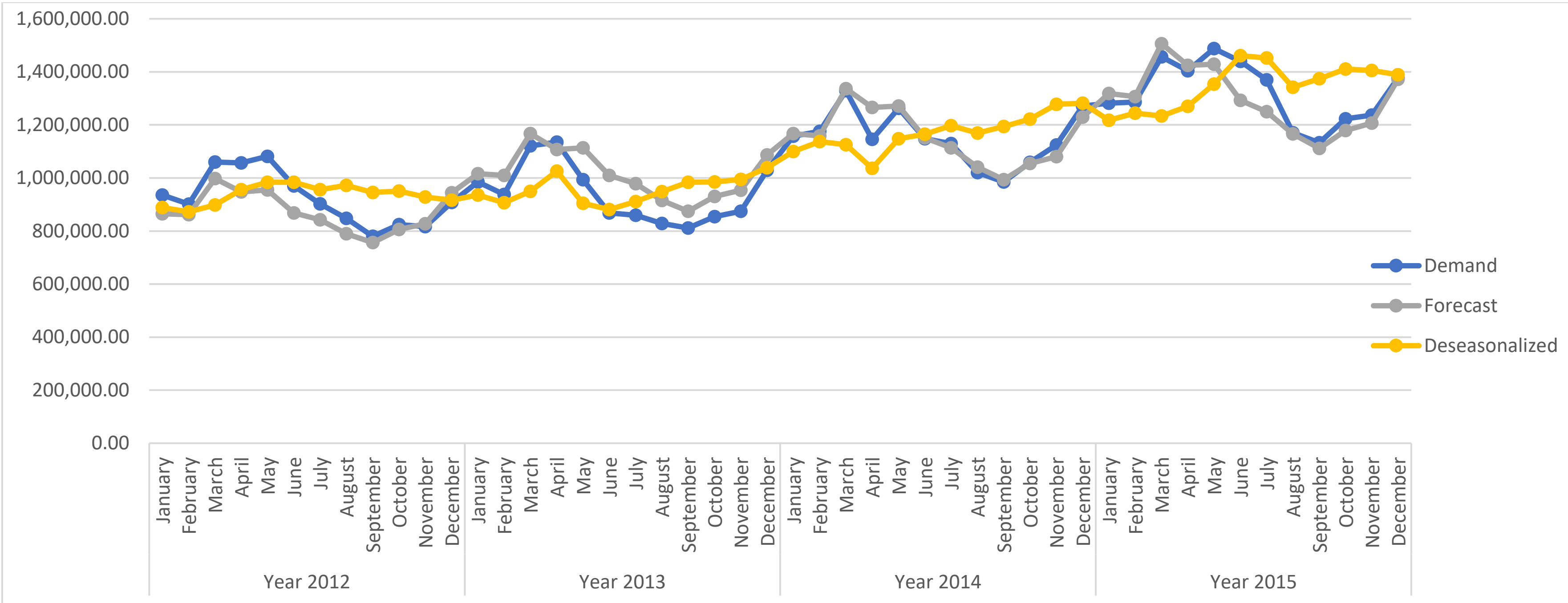


Figure 20: Forecasted Electrical Demand for San Cristobal

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,32E+12	1,32101E+12	287,0107265	2,11804E-21
Residual	46	2,12E+11	4602643102		
Total	47	1,53E+12			

	Coefficients	*Standard Error*	*t Stat*	***P-value***	*Lower 95%*	*Upper 95%*	*Lower 95,0%*	*Upper 95,0%*
Intercept	**809216,2**	19894,59	40,67519097	**1,03334E-37**	769170,4688	849261,9	769170,4688	849261,9293
t	**11975,01**	706,8491	16,94139093	**2,11804E-21**	10552,1929	13397,82	10552,1929	13397,81963

Figure 21: Regression analysis for demand evolution

4.4.2 Generation input

The output power of each of the generating units, as well as the model and year of installation are provided in Table 30. This data will be introduced in Homer Pro, as well as some other inputs below specified.

- Diesel Generators

  Cost per KW: This data was not provided by ELECGALAPAGOS, as it was considered confidential. It was not possible to obtain from Caterpillar the price of a new Diesel generator, but some websites [65] [66] are focused on second hand Generators, and the Caterpillar 3512 DITA price was estimated according to the data, as 600 $ per KW.
  Replacement cost: It Is estimated to be an 80%, as the paper [67] explains for a Homer Pro simulation in Bangladesh.
  Diesel Cost: Provided by ELECGALAPAGOS, at a total of 0.98 $/L, as well as the chemical parameters of the specific used fuel.

- Wind turbines

  Cost of the turbines: It was provided by ELECGALAPAGOS, at a total 2.400.000 $ per unit considering installation and shipping. The price is remarkably higher than the continental, as the transport costs have a big impact. The standard price for the generators, which are manufactured by GAMESA, is 1.400.000 €. [68]
  Wind Power Curve: This data is provided in the technical report [69], which contains the technical specifications of the MADE AE-59.

- PV system

  Cost per Installed KW: There is no information about the price, as the current installation is almost negligible. However, for future projects the PV capacity has potential to be increased, as an important presence of PV generation currently sources Santa Cruz, Table 29. The estimated price is 4,25 $ per Wat [70], obtained from other projects in for Islands in the Pacific.

4.4.3 Natural resources

The Island currently supports Wind and Solar renewable energy installations, so the wind speed and the solar irradiance parameters were obtained.

- Wind Speed: Report [69], provides the wind speed data measured at El Tropezón, Table 32, which is the 600m hill were the turbines are placed. The entered data was the average among the given years in the table.

WIND SPEED (m/s)								
Month \ Year	2008	2009	2010	2011	2012	2013	2014	2015
Jan	3.5	4.2	6.1	6	4.7	5.1	5.3	5.2
Feb	3.5	4.2	5.5	4.5	3.8	3.8	5.1	4.8
Mar	3.5	6.1	4.4	4.7	5.5	4.5	3.5	3.8
Apr	3	4.3	5	3.5	4.6	3.5	5	4.3
May	4.3	5.3	8.1	8.3	6.1	6.4	6.3	5.4
Jun	5.3	5.8	8.2	8.6	7	7.1	6.3	5.7
Jul	5.2	6.6	7.8	8.6	7.3	6.2	6.9	6.3
Aug	4.7	6.3	7.1	8.7	8.6	6.5	6	6.8
Sep	5.1	6.6	7.3	7.6	7.9	6.2	6.8	6.3
Oct	4.1	5.7	7.1	8.2	7.4	6.1	6.4	6.6
Nov	5.5	5.9	8.2	7.7	6.9	6.2	5.8	6.3
Dec	5.3	5.5	7.2	6.7	7.2	6.8	5.8	5.5

Table 32: Wind speed in San Cristobal

- Solar irradiance: The resource data was obtained from National Aeronautics and Space Administration (NASA) surface and solar energy database [71]. This is a global database of measures performed between 1983 to 2003.

4.5. Case Scenarios

4.5.1 Structure and considerations

Three different cases are considered, and each of them will be simulated from 2015 to 2025 as explained in the Introduction. For a detailed analysis, each of the Scenarios will be reconsidered every 5 years, as the increase of demand forces the Island to increase the generating capacity. The logic behind possible additions to the System will be explained in each scenario.

The three cases that will be consider are:

- **Case 1: Thermal Relying Option**. This scenario will replicate the actual situation, and will not prioritize the usage of renewable energy. Using the current intallations will be the objective, and if future expansions are strictly required, two generators that were bought by ELECGALAPAGOS on 2015 but not yet installed will be added. It is intended to be a realistic and economic scenario.
- **Case 2: 50% Renewable**. The Scenario 2 will always consider what the Island already is using and is planning to install, and try to contribute towards a greater DRE penetration. As an example, for the 2015 simulation it will consider possible case of replacing the three Caterpillar 3512 DITA generators that were installed in 1990 by Renewable Energy. The generators lifetime is close to its end, and a further installation of renewable energy could increase the subsidies and continue the ecotourism plan that Galapagos has committed. The aim is to obtain a close to 50% of renewable energy

penetration with the current installed capacity, without having to get rid of generators whose lifetime is not over.

- **Case 3: 100% Renewable**. The island will be fully supplied by Renewable Energy, by increasing the Wind turbines installed and adding PV penetration.

For each of the cases, the results regarding the three following points have been commented:

Feasible Configuration: The different feasible solutions provided by Homer Pro are displayed, and the important parameters as the generating units selected for the scenario are explained.

Electrical: Consists on an analysis of the feasible solution from the energetic point of view. The operating units and the contribution of each of them among the simulated period are included.

Cost summary: This point is not included in every scenario, as a cost comparison is done in Section 4.5.3, however, for the scenarios where the cost analysis have remarkable information, it will be added.

After the scenario for each year is analyzed, a comparison between all the results for emissions, costs, and COE will be performed.

It is important to state that the costs analysis will not consider the income provided by selling electricity to the consumers, nor the existing subsidies which cover the actual non-profitable system. The subsidies for San Cristobal Island accounted for a total of 25539 $/KWh as for 2005 [72]. The funds are currently justified by the presence of renewable energy, and a greater penetration of DRE would involve higher subsidies.

4.5.2. San Cristobal 2015

The first picture of the System was done for the 2015 demand, so as to have a view of the system for the first year in the simulation and have the capability to contrast the results obtained for the last simulated year, 2025.

The first step in the configuration of the software is the introduction of the geographical coordinates of the project. This shows the accuracy of Homer Pro, which customizes since the beginning each simulation, to match in the best way the real conditions.

Figure 22: Geographical coordinates of San Crsitobal

After locating the project, the demand for each of the 8670 hours of the year was introduced, and Homer Pro plots the monthly demand, Figure 23 and the average day profile for each month, Figure 24. This has the purpose to validate the introduced data.

Monthly demand

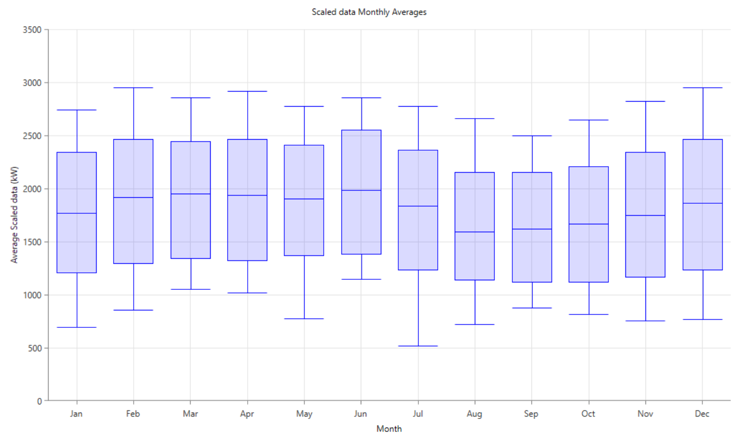


Figure 23: Monthly demand San Cristobal 2015

Peak month corresponds to December, as it is the time of the year more tourists are able to visit the Island, as the majority come from Ecuador, and summer holidays are fixed during this period. It is interesting to state that as the island lays in the Equator, there is not a great weather variability during the seasons, which is translated to some extent into a flat profile. Temperatures stay in a thin range during the year, having a rainy slightly warmer season from January until June and a drier and slightly colder from July to December.

Daily profile

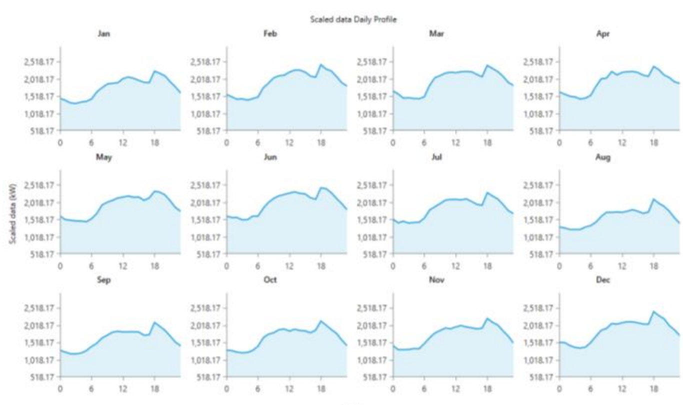


Figure 24: Daily profile 2015

The daily profile does help to validate the introduced parameters, as it follows a logical pattern. Night hours are the low demand time, while evenings, when lighting systems are under maximum service corresponds to the peak time consumption. Plus, as daylight next to the equator does not vary during the entire year, the typical shift to the left in consumption associated with earlier sunset during winter cannot be seen.

4.5.2.1 Year 2015 Scenario 1: Thermal Relying Option

Feasible Configuration

After running the simulation, Homer Pro sorts the different configurations by the NPV of the project, in case the user defines any variable as sensible. For the first scenario, there is no need of any of them, however, with the purpose of validating the actual model and verifying wetherr it is the optimal one or not, all the current generaion systems have been deignated as optional. So Homer Pro has evaluated 2567 different solutions, as Figure 25 displays.

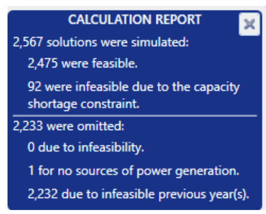


Figure 25: Analyzed possible configurations case 1 from 2015

Figure 26 shows the 6 first solutions sorted by NPV, where the it is interesting to notice that the current configuration of the island is not included among the optimal ones. For each case, Homer Pro concludes that there is over-capacity, so some generators could be removed, and with only 3 the Island could be supplied.

PV (kW)	AE59	Cat 3512 - A (kW)	MTU (kW)	Perkins (kW)	Cat 3516 (kW)	Cat 3512 - B (kW)	Cat 3512-C (kW)	Dispatch	COE ($)	NPC ($)	Operating cost ($/yr)	Initial capital ($)	Ren Frac (%)
12.5	3	650			1,100	650		LF	$0.269	$55.3M	$3.61M	$8.69M	27.5
12.5	3	650			1,100		650	LF	$0.269	$55.3M	$3.61M	$8.69M	27.5
12.5	3				1,100	650	650	LF	$0.269	$55.3M	$3.61M	$8.69M	27.5
	3	650			1,100	650		LF	$0.269	$55.3M	$3.61M	$8.64M	27.4
	3	650			1,100		650	LF	$0.269	$55.3M	$3.61M	$8.64M	27.4
	3				1,100	650	650	LF	$0.269	$55.3M	$3.61M	$8.64M	27.4

Figure 26: Simulation results 2015 optimal case 1

Back to the current situation, Homer Pro is reconfigurated, and the sensitivity variables are removed, obtaining the real configuration of the island, Figure 27. The most interesting factor when comparing the optimal configuration with the current one, is that the COE increases from 0,269 $/Kwh to 0,274 $/Kwh. The reasond behind it, is that the five generators suppose a greater initial capital, +1,61 M$ compared with the three necessary generators in the optimal case. The optimal case has a slightly higher operating cost of 4000 $ per year, as the operating capacity of the generators would be higher, however it does not compesate the gap that the initial investent created.

Architecture									Cost				System	
PV (kW)	AE59	Cat 3512 - A (kW)	MTU (kW)	Perkins (kW)	Cat 3516 (kW)	Cat 3512 - B (kW)	Cat 3512-C (kW)	Dispatch	COE ($)	NPC ($)	Operating cost ($/yr)	Initial capital ($)	Ren Frac (%)	Total Fuel (L/yr)
12.5	3	650	1,000	1,000	1,100	650	650	LF	$0.274	$56.4M	$3.57M	$10.3M	27.5	3,197,600

Figure 27: Simulation results 2015 case 1

To further comprenhend the figures of the obtained COE, it's average in 19 countries and San Cristobal Island result have been obtained, and plotted in Figure 28.

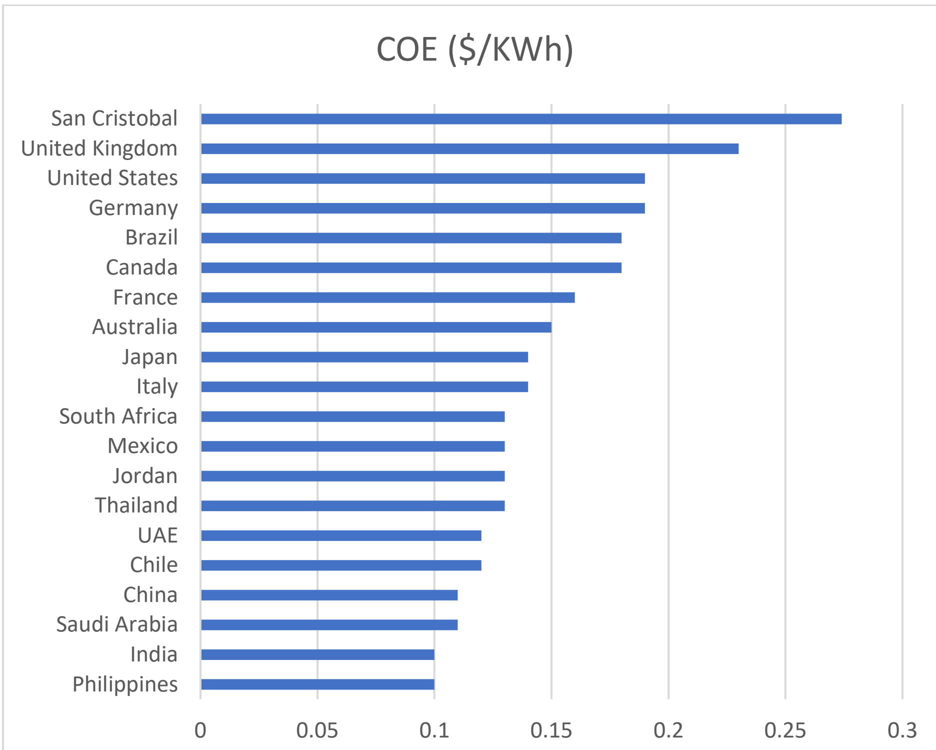


Figure 28: COE by country

From the figure, it can be extracted the conclusion that the geographical challenges of an island, transport, installation, make an electrical project not competitive against better located countries or sites. In Section 4.5.5.3. COE Evolution the obtained figures will be compared with more similar cases.

Electrical

Figure 29 shows the electrical generation of each type of device per month. As it can be seen, 27,5 % of the generation corresponds to renewable energy from the Wind Turbines. It is interesting to note that the turbine maximun electrical output corresponds to the windier months, from June to November, as Table 32 indicated between 2008 to 2015. During the rainy and warmer season, the wind turbines are not capable to provide an steady output, which will be a challenge for the fully renewable scenario, and force to introduce PV technology.

Production	kWh/yr	%
Generic flat plate PV	22,271	0.135
Caterpillar 3512 DITA	2,193,723	13.3
MTU 16V 2000 G85	1,380,486	8.37
Perkins PS1386E	5,158	0.0313
Caterpillar 3516	7,376,742	44.7
Caterpillar 3512 DITA	560,700	3.40
Caterpillar 3512 DITA	18,469	0.112
MADE AE59	4,944,659	30.0
Total	16,502,208	100

Consumption	kWh/yr	%
AC Primary Load	15,904,568	100
DC Primary Load	0	0
Deferrable Load	0	0
Total	15,904,568	100

Quantity	kWh/yr	%
Excess Electricity	597,640	3.62
Unmet Electric Load	0	0
Capacity Shortage	0	0

Quantity	Value
Renewable Fraction	27.5
Max. Renew. Penetration	280

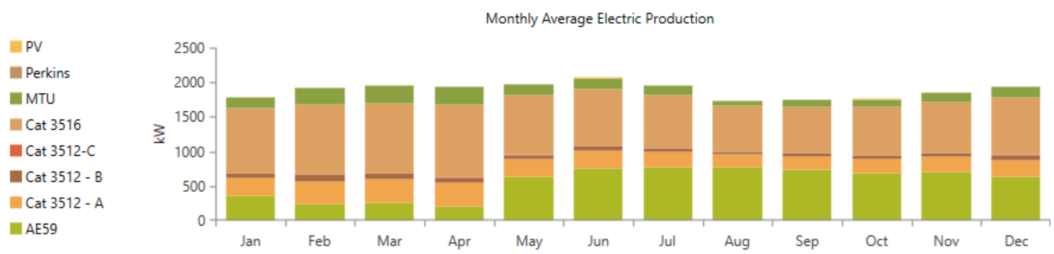


Figure 29: Electrical summary 2015 case 1

For a further understanding of how the system works and how detailed are Homer Pro simulations, Figure 30 shows, for a week in late august, the total hourly demand and the wind turbines electrical output. It can be seen that demand is fully covered during a considerable part of each day only by the installed Wind capacity. Furthermore, the wind turbines produce at many times an excess of electricity, and this is a recurrent situation from June to November, that finally results in a 3,62 % unused electricity per year.

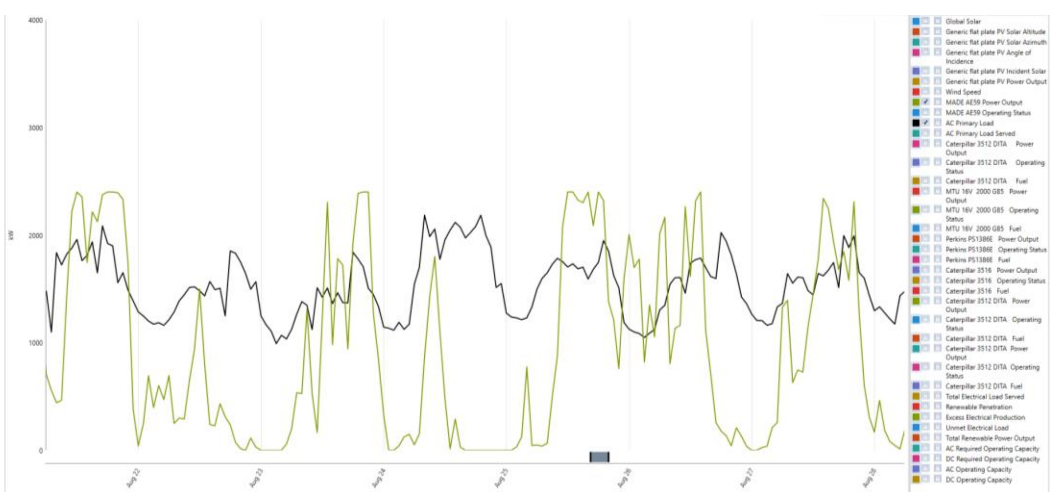
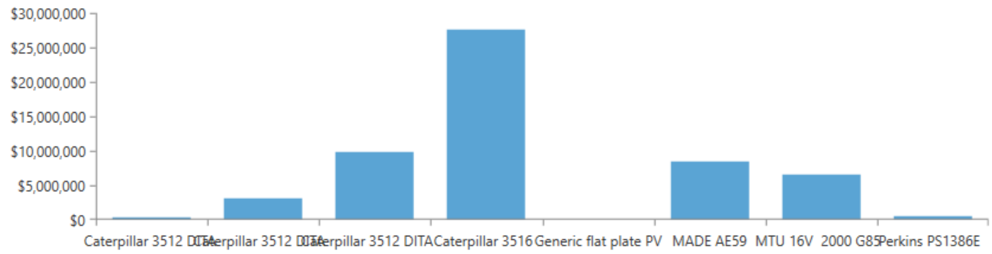


Figure 30: Weekly analysis 2015 case 1

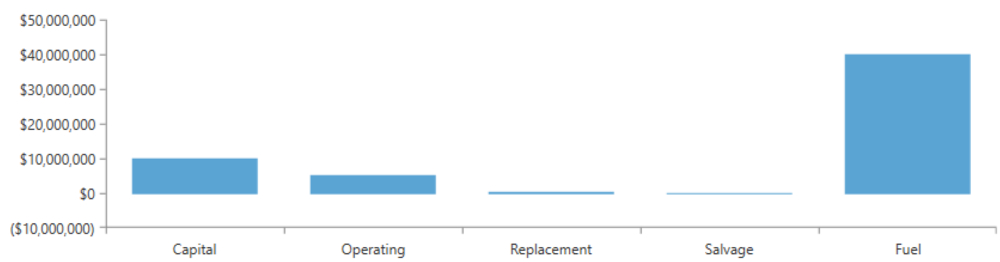
Cost summary

Figure 31 and 32 show the costs of the system from different points of view. The generator Caterpillar 3516 has been the major support for the system, as it was shown in the electrical summary, Figure 29. The generator has finished the simulation with a capacity factor of 76,6%, which has lead to 2.310.306 $ expenditure in Operation and maintenance, and 24.333.179,99 $ in fuel, which is the major cost.



Component	Capital ($)	Replacement ($)	O&M ($)	Fuel ($)	Salvage ($)	Total ($)
Caterpillar 3512 DITA	$390,000.00	$0.00	$16,805.77	$82,254.17	($72,665.88)	$416,394.06
Caterpillar 3512 DITA	$390,000.00	$0.00	$397,792.61	$2,342,954.66	($25,599.15)	$3,105,148.12
Caterpillar 3512 DITA	$390,000.00	$128,517.14	$974,734.75	$8,368,762.28	($29,066.35)	$9,832,947.82
Caterpillar 3516	$660,000.00	$416,178.37	$2,230,306.86	$24,333,179.99	($103,929.78)	$27,535,735.45
Generic flat plate PV	$53,125.00	$0.00	$1,615.94	$0.00	$0.00	$54,740.94
MADE AE59	$7,200,000.00	$0.00	$1,163,476.49	$0.00	$0.00	$8,363,476.49
MTU 16V 2000 G85	$600,000.00	$0.00	$684,382.73	$5,363,772.70	($30,439.82)	$6,617,715.61
Perkins PS1386E	$600,000.00	$0.00	$2,068.40	$19,370.73	($114,732.24)	$506,706.90
System	$10,283,125.00	$544,695.51	$5,471,183.55	$40,510,294.53	($376,433.22)	$56,432,865.38

Figure 31: Economical summary by component 2015 case 1



Component	Capital ($)	Replacement ($)	O&M ($)	Fuel ($)	Salvage ($)	Total ($)
Caterpillar 3512 DITA	$390,000.00	$0.00	$16,805.77	$82,254.17	($72,665.88)	$416,394.06
Caterpillar 3512 DITA	$390,000.00	$0.00	$397,792.61	$2,342,954.66	($25,599.15)	$3,105,148.12
Caterpillar 3512 DITA	$390,000.00	$128,517.14	$974,734.75	$8,368,762.28	($29,066.35)	$9,832,947.82
Caterpillar 3516	$660,000.00	$416,178.37	$2,230,306.86	$24,333,179.99	($103,929.78)	$27,535,735.45
Generic flat plate PV	$53,125.00	$0.00	$1,615.94	$0.00	$0.00	$54,740.94
MADE AE59	$7,200,000.00	$0.00	$1,163,476.49	$0.00	$0.00	$8,363,476.49
MTU 16V 2000 G85	$600,000.00	$0.00	$684,382.73	$5,363,772.70	($30,439.82)	$6,617,715.61
Perkins PS1386E	$600,000.00	$0.00	$2,068.40	$19,370.73	($114,732.24)	$506,706.90
System	$10,283,125.00	$544,695.51	$5,471,183.55	$40,510,294.53	($376,433.22)	$56,432,865.38

Figure 32: Economical summary by cost category 2015 case 1

Figure 32 depicts the cost from a different perspective, where it can be appreciated that fuel is the major cost contributor for the system during the simulated period, 4 times more than the second biggest expenditure, the inintial capital. This pattern is typical for thermal technology, as the installations are not as expensive as for renewable technology, but the fuel later levelizes the final figures.

4.5.2.2. Year 2015 Scenario 2: 50% Renewable

As explained in the introduction, the Scenario 2, trying to implement a greater renewable generation avoiding unnecesary extra costs, will consider the replacement of the thee oldest generators of the island.

As the last installed DRE was in 2007, and in order to further commit with the sustainability plan, the 3 generators will be replaced by Renewable Energy sources. Aiming to obtain the most feasible result, and to be in line with the current installations, it will only be considered the possibility of placing wind turbines or PV-systems. The reason is that both technologies are already widely used across the islands. The number of wind turbines has been left as a sensible variable(between 0 and 5) , as well as the installed PV capacity (between 0 and 4000 KW). Therefore, Homer will run a case for each of the options, and show all possible solutions, which are 12.695 as Figure 33 shows.

To take advantage of the excess of energy that was discovered in the Scenario 1, and try to decrease the amount of it, it has been added storage capacity. The selected storage technology has been Li-Ion, as this type of battery is already installed in Santa Cruz and Baltra Islands [63].

The last added equipment is a converter, as the DC output from the PV system and batteries need conversion to the AC grid. The converter will be optimized by Homer Pro and selected from the software library, and it will choose the most economic option.

Figure 33: Simulation scheme and report

Feasible Configuration

Architecture									Cost				System	
PV (kW)	Extra PV (kW)	AE59	Perkins (kW)	Cat 3516 (kW)	MTU (kW)	LI ASM	Converter (kW)	Dispatch	COE ($)	NPC ($)	Operating cost ($/yr)	Initial capital ($)	Ren Frac (%)	Total Fuel (L/yr)
12.5	1,436	4	1,000	1,100		2,043	1,432	LF	$0.263	$53.9M	$2.72M	$18.7M	47.2	2,297,914
12.5	1,436	4		1,100	1,000	2,043	1,432	LF	$0.263	$53.9M	$2.72M	$18.7M	47.2	2,297,914
12.5	119	5	1,000	1,100	1,000	1,785	1,229	LF	$0.265	$54.5M	$2.99M	$15.9M	41.2	2,558,184
12.5		5	1,000	1,100	1,000	1,767	1,231	LF	$0.265	$54.6M	$3.03M	$15.3M	40.3	2,599,736
12.5	1,867	4	1,000		1,000	2,059	1,246	LF	$0.274	$56.2M	$2.77M	$20.4M	49.7	2,353,306

Figure 34: Simulation results 2015 case 2

The 5 best solutions for scenario 2 are shown Figure 34, with the two top classified ones having obtained the same figures, as each of them chooses the same renewable configuration and two diesel generators, but one selects the MTU and the other the Perkins instead. In case it had been possible to obtain quotation for each of the generators, this issue would not have appeared. The suitable configuration implies a reduction of 4,01% of the COE with resopect the scenario 1 , and a renewable penetration of 47,2 %. It is a more profitable configuration, even though it does not consider the subsidies that the Government is bound to provide.

Electrical

Production	kWh/yr	%
Generic flat plate PV	22,271	0.127
Generic flat plate PV (1)	2,558,760	14.6
Perkins PS1386E	2,054,930	11.7
Caterpillar 3516	6,325,866	36.0
MADE AE59	6,592,879	37.6
Total	17,554,706	100

Consumption	kWh/yr	%
AC Primary Load	15,869,934	100
DC Primary Load	0	0
Deferrable Load	0	0
Total	15,869,934	100

Quantity	kWh/yr	%
Excess Electricity	1,537,837	8.76
Unmet Electric Load	34,634	0.218
Capacity Shortage	172,196	1.08

Quantity	Value
Renewable Fraction	47.2
Max. Renew. Penetration	380

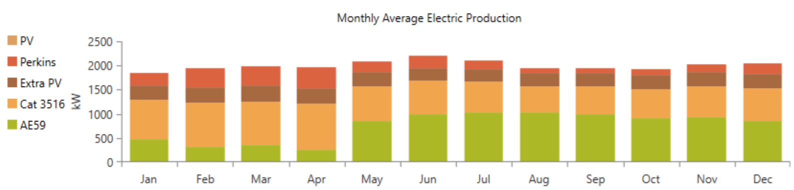
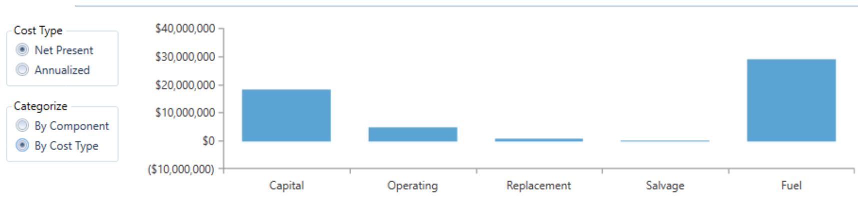


Figure 35: Electrical summary 2015 case 2

For this configuration, there is a noticeable increase in the PV contribution, which remains constant during the whole year. During the windy months, more than 60 % of the generated energy comes from renewable resources, while from January to April, the generator Caterpillar 3516 acts as main supply, with the MTU as backup.

Cost summary (By cost type+by component)

Figure 36 demonstrates fuel is still the major contributor for the costs, with almost 30 million USD in expenditure, however, capital investment is not far behind, with around 20 million. This is the logical response due to the higher renewable penetration.



Component	Capital ($)	Replacement ($)	O&M ($)	Fuel ($)	Salvage ($)	Total ($)
Caterpillar 3516	$660,000.00	$258,530.28	$2,048,856.24	$20,960,206.97	$0.00	$23,927,593.49
Generic 1kWh Li-Ion [ASM]	$1,225,800.00	$520,074.86	$264,109.16	$0.00	($97,883.34)	$1,912,100.69
Generic flat plate PV	$53,125.00	$0.00	$1,615.94	$0.00	$0.00	$54,740.94
Generic flat plate PV (1)	$6,103,641.05	$0.00	$185,658.64	$0.00	$0.00	$6,289,299.69
MADE AE59	$9,600,000.00	$0.00	$1,551,301.99	$0.00	$0.00	$11,151,301.99
Perkins PS1386E	$600,000.00	$149,617.32	$1,140,982.61	$8,151,990.70	($89,019.70)	$9,953,570.93
System Converter	$429,738.07	$182,326.61	$0.00	$0.00	($34,315.71)	$577,748.97
System	$18,672,304.12	$1,110,549.08	$5,192,524.58	$29,112,197.66	($221,218.74)	$53,866,356.69

Figure 36: Economical summary by cost category 2015 case 2

4.5.2.3. Year 2015 Scenario 3: 100% Renewable

The third scenario consists on transforming San Cristobal into a 0-emission Island. For its achievement, it will be only considered wind and solar as possible renewable energies, as they are already installed through Galapagos and have proven to be a reliable method of energizing.

This option will probably require storage, and for that, Lead-Acid battery will be considered as this type of batteries are already installed in Santa Cruz and Baltra Islands.

The capacity of all components has for this scenario has been left as optimizable, so Homer will run all possible configurations, and select the most suitable ones. This is called HOMER optimizer, and enables Homer Pro to test any possible combination, and it shows the relevant ones.

Feasible Configuration

Architecture						Cost				System	
PV (kW)	AE59	LI ASM	LA ASM	Converter (kW)	Dispatch	COE ($)	NPC ($)	Operating cost ($/yr)	Initial capital ($)	Ren Frac (%)	Total Fuel (L/yr)
9,858	5	41,489		2,871	LF	$0.475	$97.1M	$1.35M	$79.7M	100	0
8,252	8		67,746	3,340	LF	$0.497	$102M	$2.01M	$75.6M	100	0
14,522		62,278		4,422	LF	$0.606	$124M	$1.80M	$100M	100	0
12,699			122,142	3,950	LF	$0.633	$129M	$2.90M	$91.8M	100	0
	42		196,854	12,062	LF	$1.09	$222M	$4.53M	$163M	100	0
	42	126,817		8,937	LF	$1.17	$239M	$4.63M	$180M	100	0

Figure 37: Simulation results 2015 case 3

After the software runs 2.636 possible scenarios, the best 6 results in terms of NPV are shown in Figure 37. The optimal configurations would be a greater PV penetration than Wind turbines, and the usage of a 42.369 KWh litium-ion battery. The PV installation will raise to 9.858 KW and 2 new wind turbines should be installed.
The second option, which has a remarkable different COE, and thus cannot be considered, is supported by a greater Wind energy penetration in detriment of the solar, and the addtion of a Pb-

Acid battery of greater capacity, as the wind energy has a gretaer coefficient of fluctuation than the solar.

Electrical

The Island would be mainly supplied by an stable PV generation, although during the windy period, the 5 wind turbines with a total combined nominal capacity of 4.500 KW would generate almost as the 9.858 installed PV plant. This shows that the wind energy is more efficient, although also more variable.

Production	kWh/yr	%
Generic flat plate PV	17,563,297	68.1
MADE AE59	8,241,099	31.9
Total	25,804,396	100

Consumption	kWh/yr	%
AC Primary Load	15,812,255	100
DC Primary Load	0	0
Deferrable Load	0	0
Total	15,812,255	100

Quantity	kWh/yr	%
Excess Electricity	8,949,255	34.7
Unmet Electric Load	92,313	0.580
Capacity Shortage	173,656	1.09

Quantity	Value
Renewable Fraction	100
Max. Renew. Penetration	838

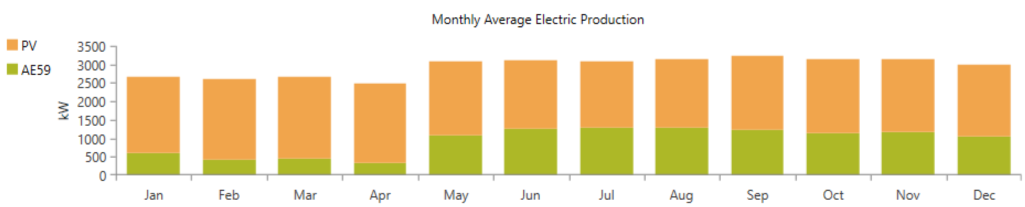


Figure 38: Electrical summary 2015 case 3

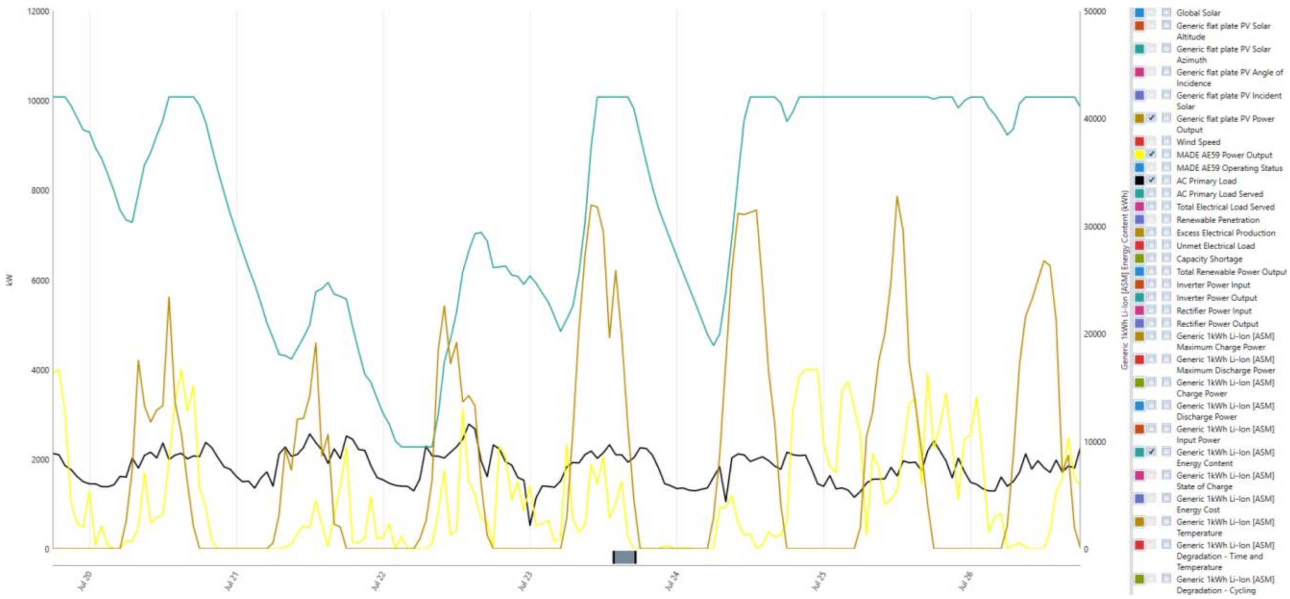
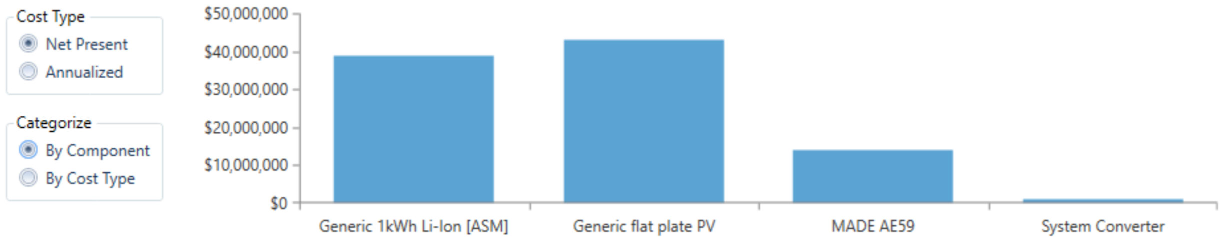


Figure 39 Weekly analysis 2015 case 3

Figure 39 shows the hourly demand for a week in July, when the wind energy is at its full usage. Through this figure, it will be explained the reason why the installed batteries have the capability to store more than 2 times the total energy consumed for any day in the island. The 20th July, a sunny and windy day, the battery was able to restore the lost capacity during the night, and began the following night fully charged. The following day, the production for both, wind and solar energy was remarkably low, and not even able to cover the daily demand, nor to recharge the batteries.The next day, the situation remained the same, and during the night, the battery stored energy entered into critical levels. It was at least during the 23rd, that wind turbines were able to work at full capacity and recharge the batteries, stabilkizing the situation.

So, it is neccesary the installation of such betteries to overcome the risks in generation that the renewable energy poses when the resources are not available during several days. Therefore, to avoid energy shortages, the battery capacity was set to be 42.369 KWh, and even though the considerable capacity,there is a 1.09% of capacity shortage through the year, as Figure 38 shows.

Cost summary



Component	Capital ($)	Replacement ($)	O&M ($)	Fuel ($)	Salvage ($)	Total ($)
Generic 1kWh Li-Ion [ASM]	$24,893,400.00	$10,561,618.15	$5,363,497.34	$0.00	($1,987,803.13)	$38,830,712.36
Generic flat plate PV	$41,895,324.93	$0.00	$1,274,358.84	$0.00	$0.00	$43,169,683.76
MADE AE59	$12,000,000.00	$0.00	$1,939,127.48	$0.00	$0.00	$13,939,127.48
System Converter	$861,409.27	$365,473.41	$0.00	$0.00	($68,785.78)	$1,158,096.89
System	$79,650,134.19	$10,927,091.56	$8,576,983.66	$0.00	($2,056,588.91)	$97,097,620.50

Figure 40: Economical summary by component 2015 case 3

The most remarkable figures from these scenario are the expenditure on the batteries, which are estimated to be 38.830.712 $ through the 25 years, as Figure 40 shows.

4.5.3. San Cristobal 2020

For 2020 and 2025 analysis , the studied demand will be the hourly forecasted data, not the real one as it was used for the 2015 scenarios. The mothly and daily profiles can be seen in Figure 41 and Figure 42 . There is a considerable pattern resemablance, however, annual demand for 2015 was 15.867.095,10 KWh while the Island is projected to sustain 25.625.872,18 KWh for 2020.

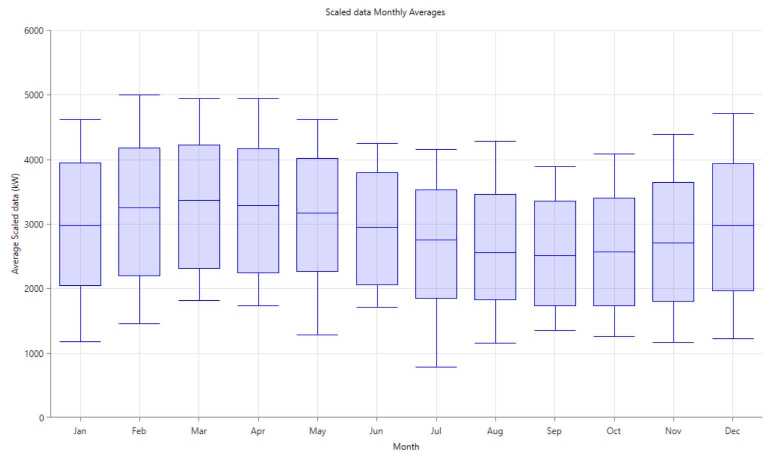


Figure 41: Monthly demand San Cristobal 2020

The forecasted hourly demand conforms the following average daily plots for each month, very similar to the 2015 case.

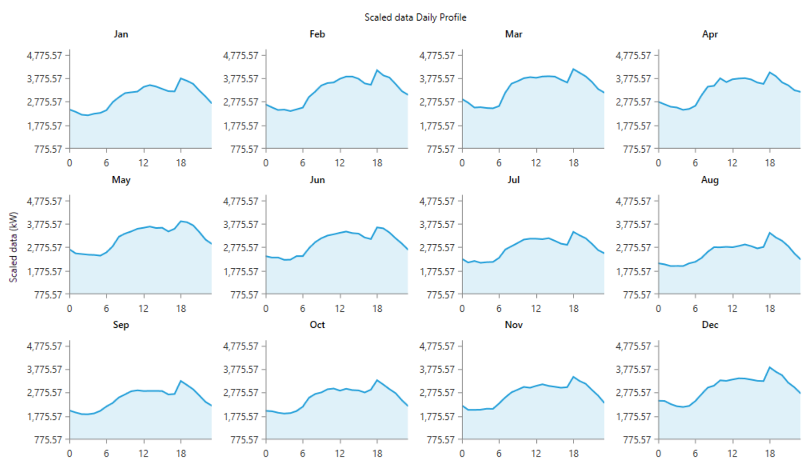


Figure 42: Daily profile 2020

4.5.3.1. Year 2020 Scenario 1: Thermal Relying Option

Feasible Configuration

The increased demand can still be sustained with the 2015 installed capacity, but the costs are increased as the generators will have to work at a higher capacity, which implies a greater fuel consumption and a higher Operating costs. Figure 43 summarizes the obtained data, pointing out that the COE will logically increase with respect 2015 situation, to 0,279 $ per KWh.

Architecture									Cost				System	
PV (kW)	AE59	Cat 3512 - A (kW)	MTU (kW)	Perkins (kW)	Cat 3516 (kW)	Cat 3512 - B (kW)	Cat 3512-C (kW)	Dispatch	COE ($)	NPC ($)	Operating cost ($/yr)	Initial capital ($)	Ren Frac (%)	Total Fuel (L/yr)
12.5	3	650	1,000	1,000	1,100	650	650	LF	$0.279	$92.6M	$6.37M	$10.3M	19.1	5,793,874

Figure 43: Simulation results 2020 case 1

Electrical

In this case the renewable fraction accounts for a 19,1% of the total output, as the generators are now under higher capacity. The excess of electricity has decreased to a total of 0,322%, as the wind generation does not exceed the demand as frequently as it happened with lower load.

Production	kWh/yr	%
Generic flat plate PV	22,271	0.0866
Caterpillar 3512 DITA	3,274,958	12.7
MTU 16V 2000 G85	4,642,061	18.1
Perkins PS1386E	1,460,437	5.68
Caterpillar 3516	8,963,857	34.9
Caterpillar 3512 DITA	1,879,724	7.31
Caterpillar 3512 DITA	520,609	2.03
MADE AE59	4,944,659	19.2
Total	25,708,578	100

Consumption	kWh/yr	%
AC Primary Load	25,625,873	100
DC Primary Load	0	0
Deferrable Load	0	0
Total	25,625,873	100

Quantity	kWh/yr	%
Excess Electricity	82,705	0.322
Unmet Electric Load	0	0
Capacity Shortage	2,907	0.0113

Quantity	Value
Renewable Fraction	19.1
Max. Renew. Penetration	175

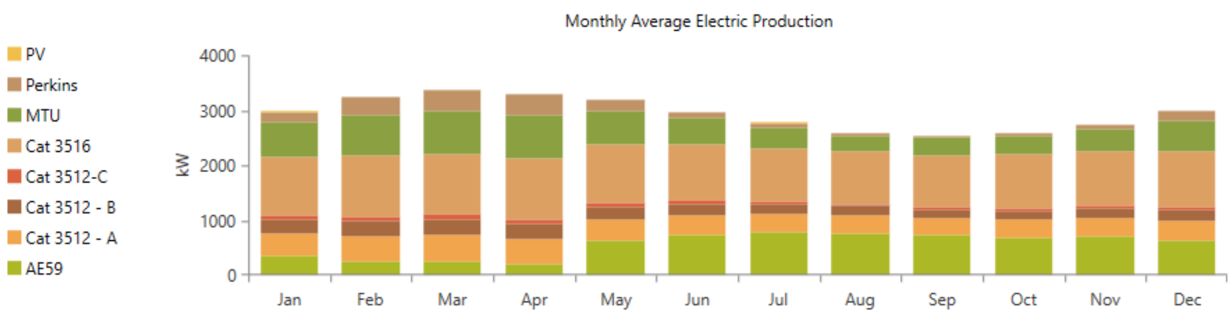


Figure 44: Electrical summary 2020 case 1

4.5.3.2. Year 2020 Scenario 2: 50 % Renewable

The 3 generators that started supporting the system in 2015 will not be replaced at least in 2020, as the machines have been working at medium-low capacity and they have an expected lifetime of 80.000 hours of operation. They were installed between 2009 and 2013, so they will be able to work minimum 10 years more.

In case the extra demand requires further capacity of the system, the sensitivity variables used in the 2015 simulation will increase to a possible 10 Wind Turbines and a 10.000 KW of maximum PV capacity, and the software will decide the perfect configuration.

Feasible Configuration

After simulating, the three generators are marked as necesssary by the Homer Pro, the software requires 2 new Wind Turbines, 1826 extra KW of PV capacity and 2889 KWh greater Litium-Ion battery respect 2015 Scenario 2.

It is interesting to notice that the software has decided to rely more heavily in the wind technology rather than the solar, as with the diesel generators acting as backup, this combination is more efficient.

The feasible configuration relies in a system composed of 48,9% renewables, with a logical increase in the COE to a total of 0,269 $ per KWh, which is below 2020 scenario 1.

Architecture								Cost				System	
PV (kW)	AE59	Perkins (kW)	Cat 3516 (kW)	MTU (kW)	LI ASM	Converter (kW)	Dispatch	COE ($)	NPC ($)	Operating cost ($/yr)	Initial capital ($)	Ren Frac (%)	Total Fuel (L/yr)
3,262	6	1,000	1,100	1,000	4,932	1,531	LF	$0.269	$88.9M	$4.28M	$33.5M	48.9	3,611,944
7,026		1,000	1,100	1,000	12,989	2,559	LF	$0.317	$105M	$4.98M	$40.3M	41.7	4,115,846
7,648	10	1,000	1,100		24,274	2,333	LF	$0.329	$109M	$2.77M	$73.0M	76.7	1,607,972
7,648	10		1,100	1,000	24,274	2,333	LF	$0.329	$109M	$2.77M	$73.0M	76.7	1,607,972

Figure 45: Simulation results 2020 case 2

Electrical

With respect the electrical coverage, the profile remains with few changes since 2015 simulation, as Figure 46 demonstrates. Although the renewable fraction accounts for 48,9%, the total production is the 54,6% . This difference is explained by the excess of energy, that accounts for the 10% of total production. This excess of energy could be minimized by the installation of additional batteries, but it would increase the final cost of the system.

Production	kWh/yr	%
Generic flat plate PV (1)	5,811,590	20.2
Perkins PS1386E	4,369,667	15.2
Caterpillar 3516	7,082,774	24.6
MTU 16V 2000 G85	1,604,665	5.58
MADE AE59	9,889,319	34.4
Total	28,758,013	100

Consumption	kWh/yr	%
AC Primary Load	25,552,218	100
DC Primary Load	0	0
Deferrable Load	0	0
Total	25,552,218	100

Quantity	kWh/yr	%
Excess Electricity	2,884,572	10.0
Unmet Electric Load	73,655	0.287
Capacity Shortage	276,712	1.08

Quantity	Value
Renewable Fraction	48.9
Max. Renew. Penetration	361

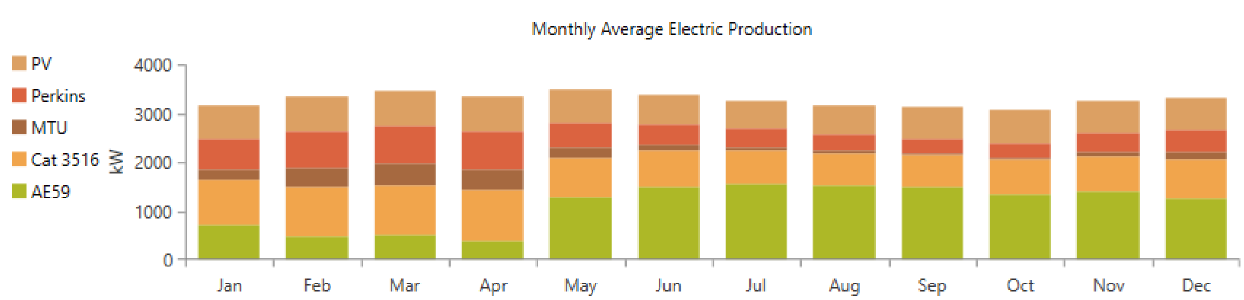


Figure 46: Electrical summary 2020 case 2

4.5.3.3. Year 2020 Scenario 3: 100% Renewable

The 2020 scenario will follow the same logic as for 2015, with all parameters left to be optimized by the software.

Feasible Configuration

Architecture						Cost				System	
PV (kW)	AE59	LI ASM	LA ASM	Converter (kW)	Dispatch	COE ($)	NPC ($)	Operating cost ($/yr)	Initial capital ($)	Ren Frac (%)	Total Fuel (L/yr)
17,326	7	67,956		4,801	LF	$0.489	$161M	$2.19M	$133M	100	0
14,590	12		111,744	4,815	LF	$0.511	$168M	$3.28M	$126M	100	0
23,748		95,696		7,191	LF	$0.598	$196M	$2.78M	$161M	100	0
19,176			206,221	6,783	LF	$0.625	$205M	$4.64M	$145M	100	0

Figure 47: Simulation results 2020 case 3

The chosen configuration to withstand 2020 demand on a fully renewable system is the installation of 7 Wind Turbines, 17.326 KW of solar panels and an array of litium-iuon batteries with a capacity of 67.956 Kwh. This supposes 2 more turbines, a 75,76% more powerful PV system and a battery with 63,8% more capacity, with respect the same scenario for 2015. The COE has risen from a 0,475 to 0,489 $ per KWh. This figure is above the typical COE for a fully renewable project, but as said previously, the challenges associated with being deployed on an island can double the price of the project.

Electrical

The electrical data is shown in Figure 48 . There is a relevant escess of electricity, a 35,8 % of the total output, as the system is producing 42.406.104 KWh per year, while the demand is 25.625.872,18 KWh.

Production	kWh/yr	%
Generic flat plate PV	30,868,566	72.8
MADE AE59	11,537,538	27.2
Total	42,406,104	100

Consumption	kWh/yr	%
AC Primary Load	25,471,061	100
DC Primary Load	0	0
Deferrable Load	0	0
Total	25,471,061	100

Quantity	kWh/yr	%
Excess Electricity	15,191,421	35.8
Unmet Electric Load	154,812	0.604
Capacity Shortage	281,237	1.10

Quantity	Value
Renewable Fraction	100
Max. Renew. Penetration	900

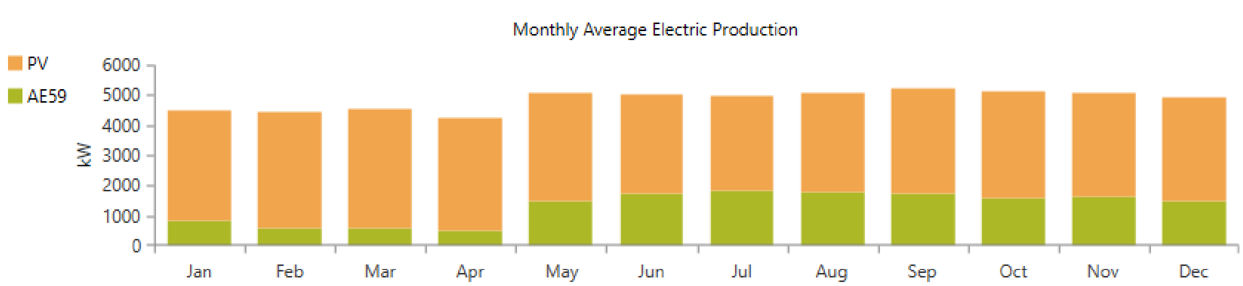


Figure 48: Electrical summary 2020 case 3

4.5.4. San Cristobal 2025

The total demand for 2025 is predicted to be 34.129.754,47 KWh, which accounts 33,18% increase with respect 2020.

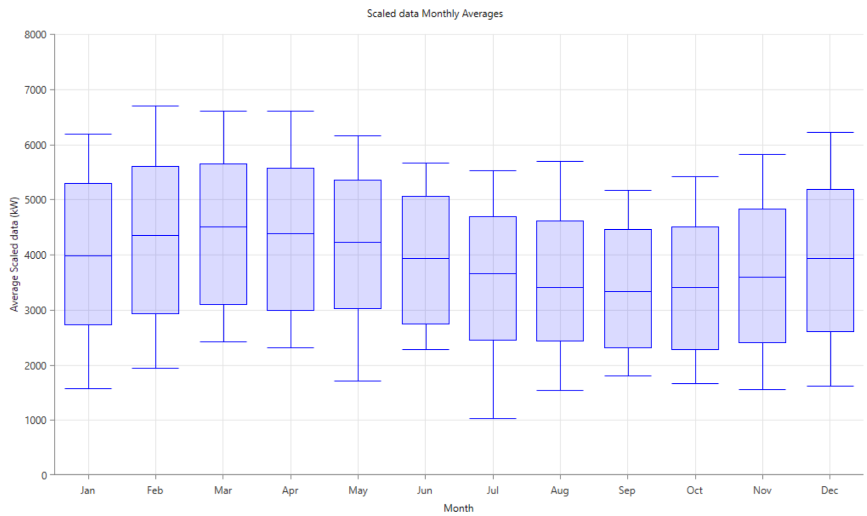


Figure 49: Monthly demand San Cristobal 2025

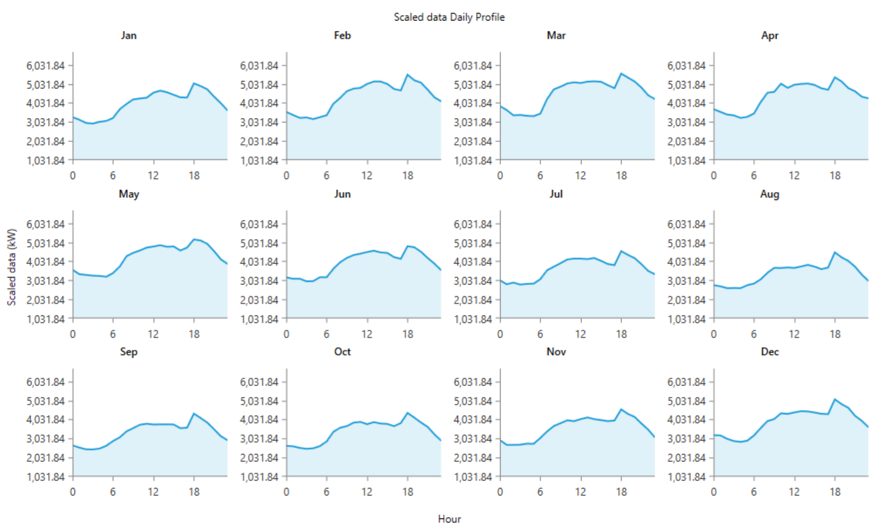


Figure 50: Daily profile 2025

4.5.4.1. Year 2025 Scenario 1: Thermal Relying Option

The first consequence of the demand increase for 2025 is that the installed capacity for year 2015 that was also capable of supplying the island in 2020 is not able to meet the load anymore. Because of this, and to maintain the simulations as close to the real situation as possible, two new generators that according to ELECGALAPAGOS [63] were installed in 2015 will be added to the system. There is no record that the generators have started operation for the time the paper is written, 2018, so it can by hypotheiszed that either they have been purchased but not yet intalled, or that they are keeping them as back up. The added generators are a MTU-DETROIT, with capacity for 1700 KW each.

Feasible Configuration

Architecture											Cost				System	
PV (kW)	AE59	Cat 3512 - A (kW)	MTU (kW)	Perkins (kW)	Cat 3516 (kW)	Cat 3512 - B (kW)	Cat 3512-C (kW)	MTU DTT (kW)	MTU DTT (1) (kW)	Dispatch	COE ($)	NPC ($)	Operating cost ($/yr)	Initial capital ($)	Ren Frac (%)	Total Fuel (L/yr)
12.5	3	650	1,000	1,000	1,100	650	650	1,700	1,700	LF	$0.288	$127M	$8.87M	$12.3M	14.5	8,171,994

Figure 51: Simulation results 2025 case 1

The resulting COE is 0,288 $ per KWh, which has increased compared to the 2020 scenario and the renewable energy fraction has decreased to a 14,5 %.

Electrical

The electrical production share of Figure 52 shows a resilient system. If the working capacity of the diesel generators is analyzed, Table 33, it will be observed that system is not at all at is maximun capacity. Only the Caterpillar 3516 has been suppling power almost the during the simulation, but as an average, all the thermal generators work at a 40.47 % of capacity. The new added generators to the system work at very low capacity, specially one of them that only operates 502 hours per year. This means that the simulated configuration could supply a demand more than twice as the forecasted for 2025.

Generators	**Caterpillar 3512 DITA**	**MTU 16V 2000 G85**	**Perkins PS1386E**	**Caterpillar 3516**	**Caterpillar 3512 DITA**	**Caterpillar 3512 DITA**	**MTU DETROIT**	**MTU DETROIT**
Hours of operation	6472 hrs/yr	6482 hrs/yr	3389 hrs/yr	8758 hrs/yr	6103 hrs/yr	3765 hrs/yr	3030 hrs/yr	502 hrs/yr
Number of starts	1509 starts/yr	1519 starts/yr	1800 starts/yr	3 starts/yr	1645 starts/yr	1949 starts/yr	1207 starts/yr	406 starts/yr
Operational life	13.9 yr	13.9 yr	26.6 yr	10.3 yr	14.7 yr	23.9 yr	29.7 yr	179 yr
Capacity factor	68.2 %	65.4 %	31 %	98.2 %	43.5 %	19.9 %	22 %	3.29 %

Table 33: Summary of generators operation 2025 case 1

Production	kWh/yr	%
Generic flat plate PV	22,271	0.0652
Caterpillar 3512 DITA	3,881,647	11.4
MTU 16V 2000 G85	5,730,938	16.8
Perkins PS1386E	2,715,521	7.95
Caterpillar 3516	9,467,178	27.7
Caterpillar 3512 DITA	2,479,025	7.26
Caterpillar 3512 DITA	1,132,862	3.32
MTU DETROIT	3,273,917	9.59
MTU DETROIT (1)	490,559	1.44
MADE AE59	4,944,659	14.5
Total	34,138,576	100

Consumption	kWh/yr	%
AC Primary Load	34,129,757	100
DC Primary Load	0	0
Deferrable Load	0	0
Total	34,129,757	100

Quantity	kWh/yr	%
Excess Electricity	8,819	0.0258
Unmet Electric Load	0	0
Capacity Shortage	0	0

Quantity	Value
Renewable Fraction	14.5
Max. Renew. Penetration	133

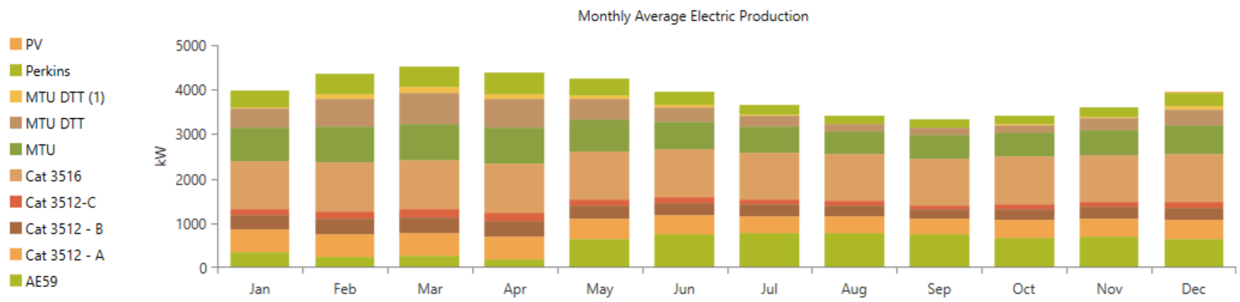


Figure 52: Electrical summary 2025 case 1

4.5.4.2. Year 2025 Scenario 2: 50% Renewable

The 33,18% of increase in demand with respect the year 2020 will mean that some extra installations will have to be added into the system. As the scenario 2 tries to get as closest as possible to a real solution, one of the two MTU DETROIT generators will be included. In addition to it, Homer Pro was left to optimize the amount of solar and wind energy.

Feasible configuration

Architecture									Cost				System	
PV (1) (kW)	AE59	Perkins (kW)	Cat 3516 (kW)	MTU (kW)	MTU DTT (kW)	LI ASM	Converter (kW)	Dispatch	COE ($)	NPC ($)	Operating cost ($/yr)	Initial capital ($)	Ren Frac (%)	Total Fuel (L/yr)
2,852	8	1,000	1,100	1,000	1,700	3,081	2,056	LF	$0.264	$116M	$6.15M	$36.7M	44.1	5,340,598
5,550	9	1,000	1,100		1,700	14,986	2,176	LF	$0.280	$123M	$5.11M	$57.1M	57.0	4,062,026
5,550	9		1,100	1,000	1,700	14,986	2,176	LF	$0.280	$123M	$5.11M	$57.1M	57.0	4,062,026
	16	1,000	1,100	1,000	1,700	6,530	765	LF	$0.285	$125M	$6.16M	$45.4M	46.1	5,116,374
6,172	9	1,000		1,000	1,700	14,455	2,197	LF	$0.289	$127M	$5.24M	$59.4M	57.9	4,142,309

Figure 53: Simulation results 2025 case 2

After running all the possible solutions to 2025 under the set up constraints, the first optimal result in terms of NPV corresponds to the usage of the four diesel generators, 8 wind turbines and a PV system with a capacity of 2852 KW. This combination would lead to a COE of 0,264 $, which would be even lower than the 0,269 $ for 2020. But there are two problems for this particular configuration that made it to be discarded for the project.

1. It does not follow the slow increase on DRE penetration that Scenario 2 has been focusing on achieving, as this case reduces the renewable energy to a 44,1 % from the 48,9% in 2020.

2. It is not coherent with the installed capacity for 2020. In 2020, the configuration for Scenario 2 was the usage of 3262 KW of solar energy and a battery with 4932 KWh capacity, and to implement these scenario the Island would have extra capacity and not be optimal.

Therefore, the chosen configuration is the second in the list, which increases the COE to 0,280 $ per Kwh, but at the same increases the renewable energy penetration to a 57%. It will consider replacing one of the 100KW diesel generators by the new MTU DETROIT. The increase in renewable energy would be by means of 3 new wind turbines and 2288KW addition to the already existing capacity.

Electrical

Regarding the electrical picture of the system, it is important to mention that from may to december, the island will be powered mainly by renewable energies, achieving the 50% renewable target that the scenario had set, with a more economical portfolio than the thermal relying scenario 1.

Production	kWh/yr	%
Generic flat plate PV (1)	9,889,046	25.1
Perkins PS1386E	3,251,396	8.26
Caterpillar 3516	6,768,694	17.2
MTU DETROIT	4,627,767	11.8
MADE AE59	14,833,978	37.7
Total	39,370,881	100

Consumption	kWh/yr	%
AC Primary Load	34,039,941	100
DC Primary Load	0	0
Deferrable Load	0	0
Total	34,039,941	100

Quantity	kWh/yr	%
Excess Electricity	4,647,216	11.8
Unmet Electric Load	89,816	0.263
Capacity Shortage	374,328	1.10

Quantity	Value
Renewable Fraction	57.0
Max. Renew. Penetration	411

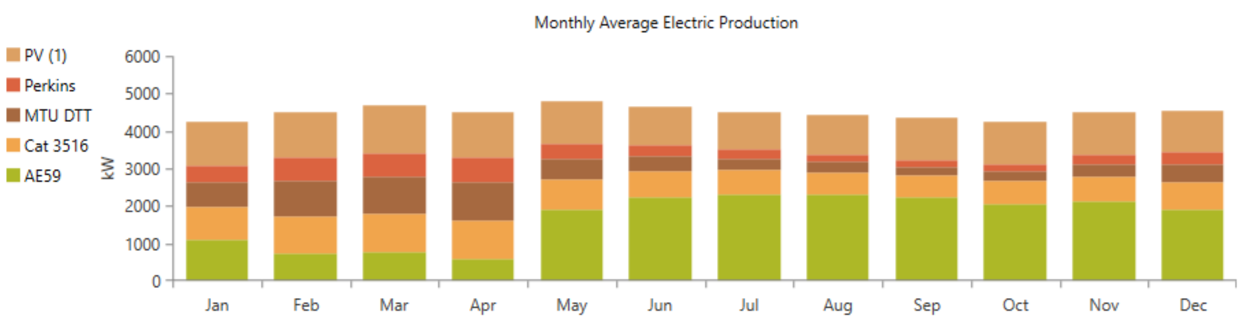


Figure 54: Electrical summary 2025 case 2

4.5.4.2. Year 2025 Scenario 3: 100% Renewable

The possible software configurations for the fully renewable alternative were disposed as for the 2020 case, without the delibarate addition of any installation.

Feasible Configuration

The most profitable alternative follows the path taken by the previous simulation in which Solar Energy is prefered over Wind resource. This is because lacking the stable output from thermal generators, only solar energy can act as a system stabilizer, and be secondarily supported by wind energy. The second and third classified scenarios are far from the best NPV solution, as the Figure 55 shows.

The second best result comes from a configuration that leans on wind energy. The consequence of a system that relies on the wind, is that the system's storage capacity must increase exponentially, which makes he system unprofitable. However, with solar technology becoming more efficient and profitable, it is a matter of time that the wind relying configuration passes the solar one.

The third result does not consider any wind turbine and the reduction of diversity of energy sources has its toll, as the probability of several cloudy days imply the necesity a great storage capacity. With some wind energy intalled the possibilities of several days with no resources would be greatly reduced.

Architecture						Cost				System	
PV (kW)	AE59	LI ASM	LA ASM	Converter (kW)	Dispatch	COE ($)	NPC ($)	Operating cost ($/yr)	Initial capital ($)	Ren Frac (%)	Total Fuel (L/yr)
22,738	10	90,588		6,418	LF	$0.490	$215M	$2.93M	$177M	100	0
20,267	15		144,090	6,928	LF	$0.512	$225M	$4.43M	$167M	100	0
31,629		127,453		9,635	LF	$0.598	$262M	$3.71M	$214M	100	0

Figure 55: Simulation results 2025 case 3

Electrical

In Figure 56, it can be seen that the configuration relies on solar energy to supply the system, with the wind acting as a secondary source.

Production	kWh/yr	%
Generic flat plate PV	40,512,489	71.1
MADE AE59	16,482,198	28.9
Total	56,994,686	100

Consumption	kWh/yr	%
AC Primary Load	33,929,993	100
DC Primary Load	0	0
Deferrable Load	0	0
Total	33,929,993	100

Quantity	kWh/yr	%
Excess Electricity	20,778,045	36.5
Unmet Electric Load	199,764	0.585
Capacity Shortage	375,348	1.10

Quantity	Value
Renewable Fraction	100
Max. Renew. Penetration	905

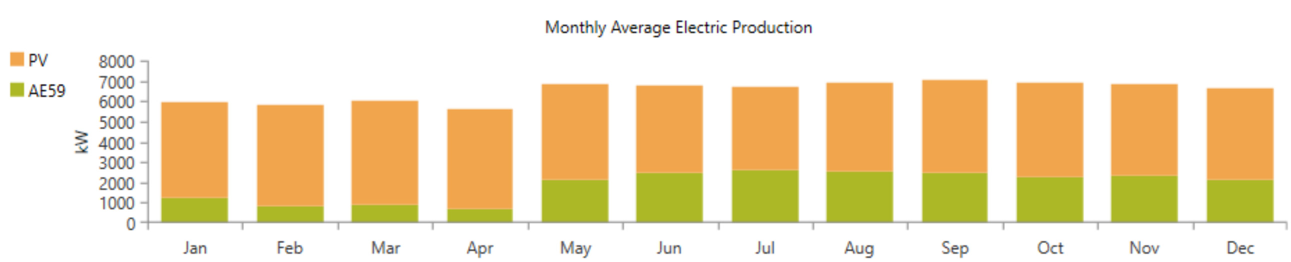


Figure 56: Electrical summary 2025 case 3

4.5.5. Comparison

4.5.5.1. Emissions

Table 34 consolidates the emission of six pollutant agents during the start of the project, and at the end of it for the two scenarios that release any particles. While the Scenario 2 does not double the release of any of the six, the scenario 1 ends up with twice pollutant emissions, with a particularly high increase in the Carbon Monoxide of 176.93%. The Scenario 2 would reach 2025 with a similar pollutant emission as the current configuration has in 2015, even though it would be supporting a load twice as big as for 2015.

	Scenario 1		Scenario 2	
Pollutant Agent	2015	2025	2015	2025
Carbon Dioxide (kg/yr)	8,376,346	21,390,760	6,021,374	10,636,249
Carbon Monoxide (kg/yr)	48,777	135,076	33,894	64,841
Unburned Hydrocarbons (kg/yr)	2,302	5,884	1,654	2,925
Particulate Matter (kg/yr)	314	691	238	368
Sulfur Dioxide (kg/yr)	20,496	52,382	14,729	26,037
Nitrogen Oxides (kg/yr)	6,811	14,509	5,218	7,852

Table 34: Emission comparison

4.5.5.2. Costs

For the sake of clarity, the graphs regrading costs of each scenario for each of the analyzed years, have been plotted separately, as Figure 57 depicts.

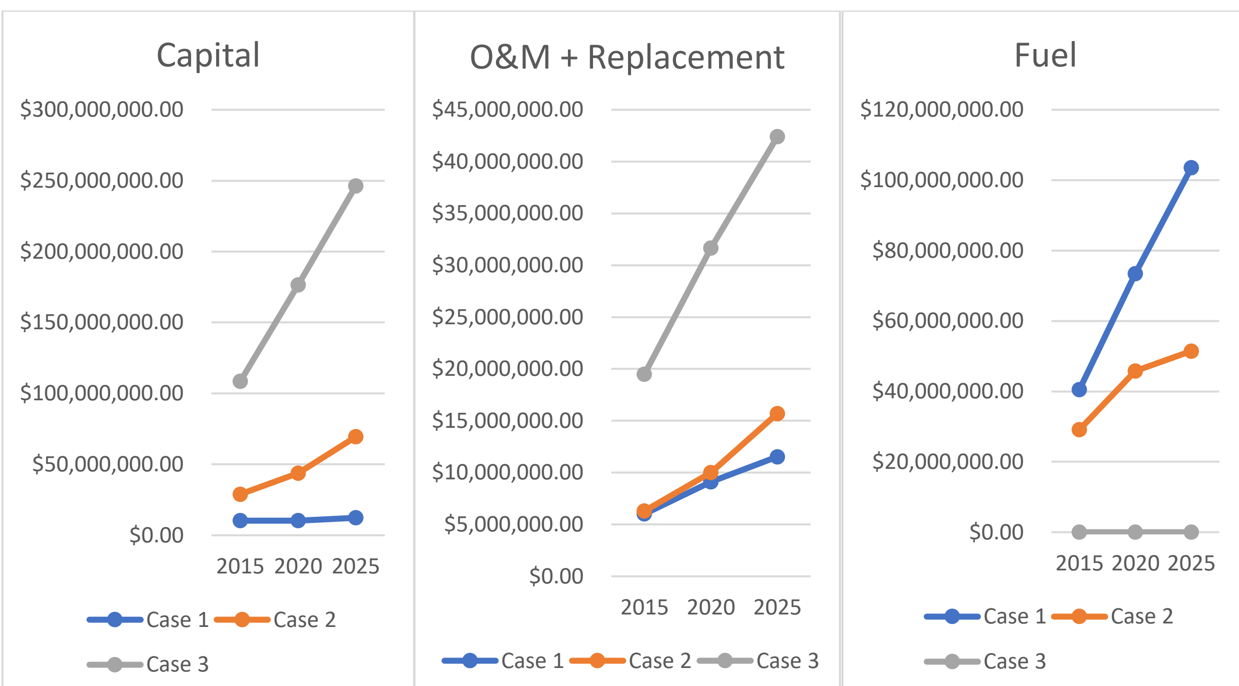


Figure 57: Final cost comparison

Figure 57 shows the evolution of the three main cost categories, the first one is the invested capital in the project, it is the upfront payment of all the installed components, the second combines the costs associated to keep the system in conditions for its usage, and the replacement. The third cost category is the fuel, and logically, one of the scenarios will not incur in any cost for this category.

Regarding the capital investment in the Island, the renewables weight the options, as nowadays the technology associated is more expensive. The fully renewable case has greater capital investment required, over 100 M$ just for the first year. The second scenario has an important increase in the required capital from 2020 to 2025, as the it is planned an important increase in the DRE penetration.

The operation and maintenance are also more expensive for renewable energy, as for the solar panels there is a rapid degradation that requires heavy maintenance. In case the scenario 3 had relied more in wind energy, the figures for this graph would not be as steep, although for the capital they would be higher, because wind energy initial investment is higher than for solar. For scenarios 1 and 2 the cost are very similar between 2015 and 2020, but they increase for case 2 as more renewable energy penetrates, and decreases for case 1 as the opposite happens.

The Fuel costs are what make the difference between case 1 and 2, leading to a more profitable second scenario. The first scenario maintains a heavy increase in consumption, while the second scenario slows it down. It is important to consider that the simulation has not considered a Diesel price increase, which is a very probable scenario, and would exponentially make scenario 1 less profitable.

4.5.5.3 COE Evolution

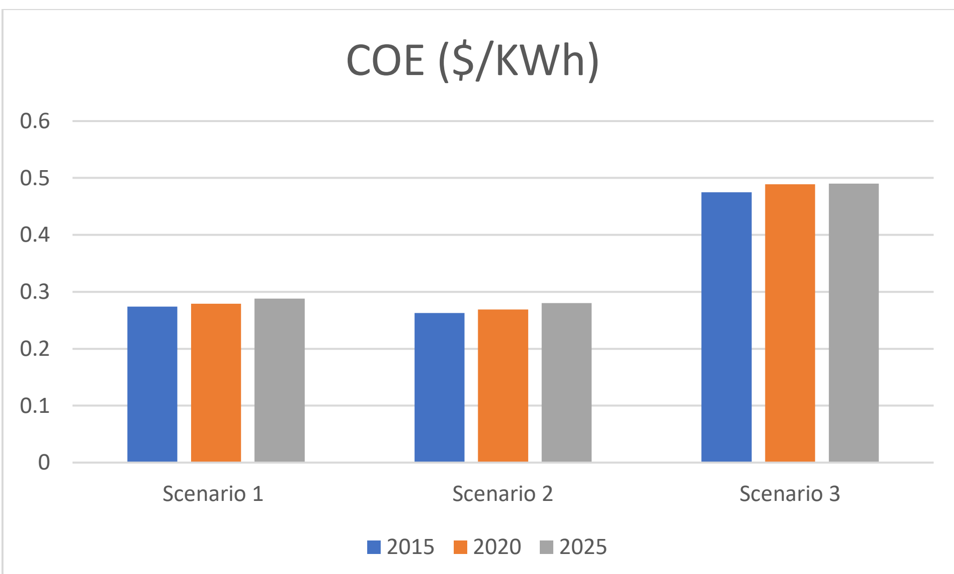


Figure 58: COE comparison of scenarios

The general picture of the COE evolution for the three scenarios is shown in Figure 58. Overall, Scenario 2 is the less expensive for each of the years, and all scenarios have an increase on the

KWh cost of production within the years, but for case 3, the increase for 2025 configuration almost remains at the same cost as 2020. This is because for 2020 the excess of demand of the proposed configuration was very high, being able to sustain almost a demand twice the 2020, so the system did not have to be upgraded in the same ways as in the other scenarios.

The Figure 28 showed the present COE for several countries, to understand the whole picture, but in the comparison more relevant data about the COE is shown in Figure 59 and **Error! Reference source not found.**.

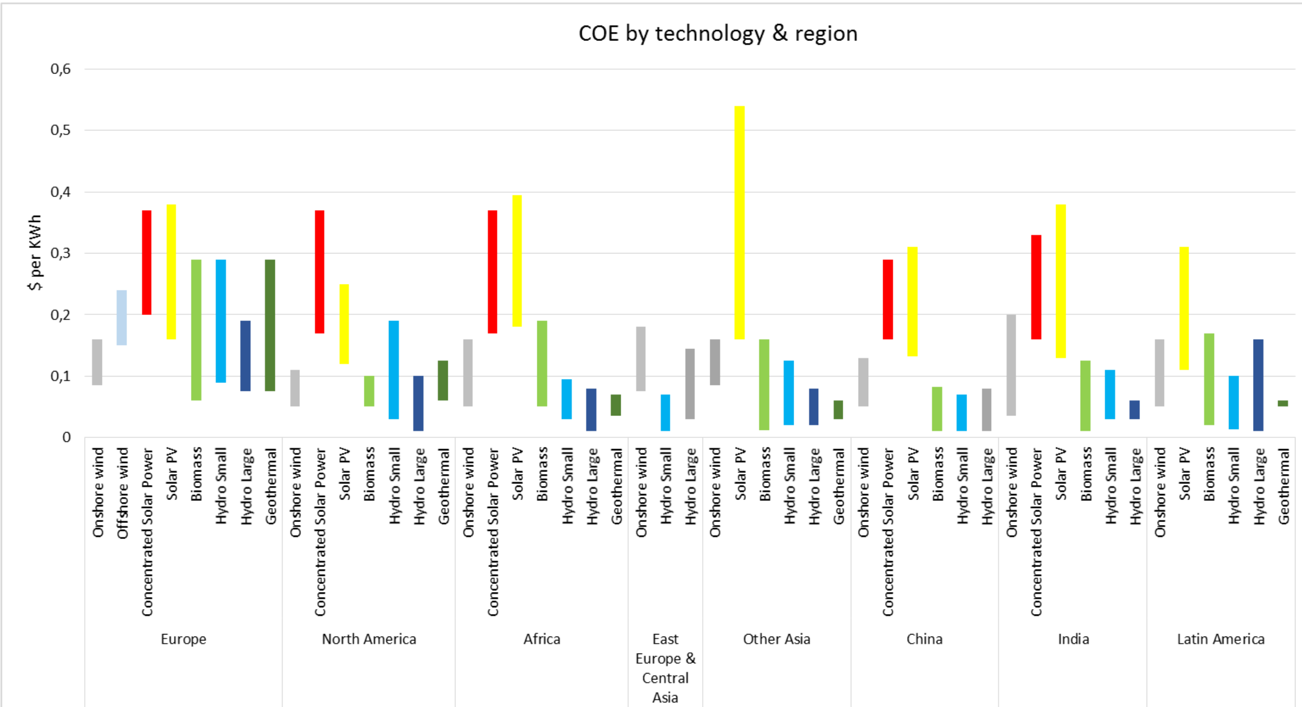


Figure 59: COE by technology and region [73]

Figure 59 compares the weighted average COE range of renewable power generation technologies by country or region. It is demonstrated that there exist significant differences in the cost ranges for different technologies in different regions. This is driven by the very site-specific nature of renewable resources and project costs. Meaning that, depending on the availability of different resources regions will be competitive in different technologies. For instance, China is very competitive in hydro power, as the three Gorges Dam is the largest hydroelectric power plant in the world, or Indonesia in Geothermal as it is highly volcanic region. The other factors that affects the project costs are the scale of the projects, and the distance from suppliers.

Once the context and the different costs of regions for each technology are defined, it is important to focus on San Cristobal case and compare it to similar scenarios regarding the size and location of the project. For this, Figure 60 compares the COE ranges of the most popular technologies, including diesel, for small and medium size Islands.

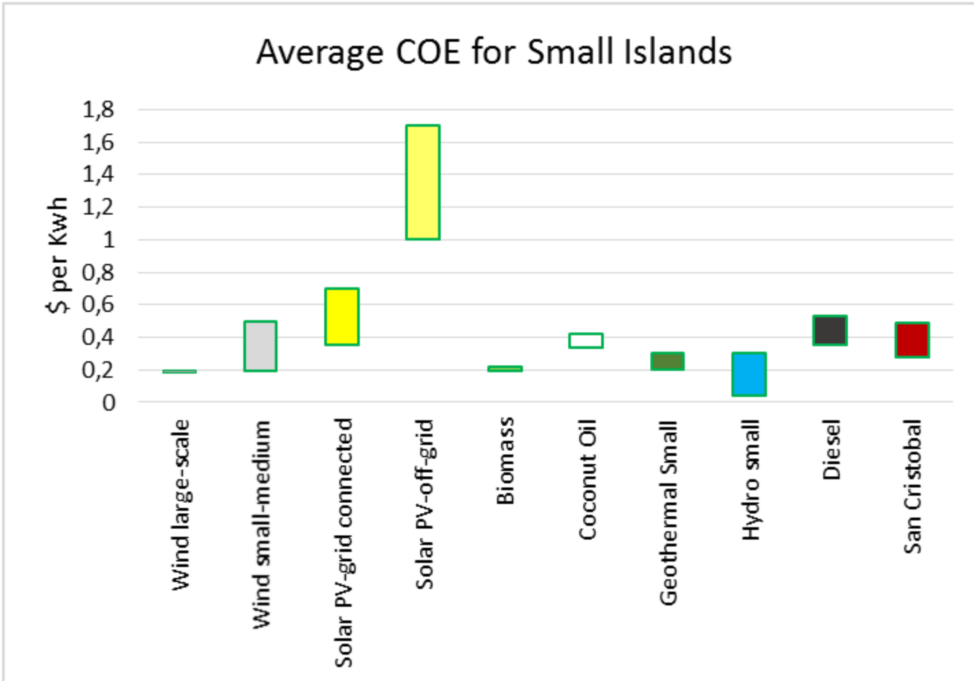


Figure 60: COE for Islands [73]

The first relevant concept that can be extracted from Figure 60 in contrast to Figure 59 is that COE for islands is typically from two to three times for islands than in the mainland. The reasons are transport costs, the fact that islands can't take advantage of economies of scale, or the extra costs of maintaining qualified personnel in the island for any installed technology. Considering this, and focusing on Figure 61, it is possible to place the obtained data through the simulations and compare in the frame of similar cases. The column San Cristobal of the figure represents the range for all the obtained COE across the simulations. A rapid check provides validation of the obtained results, as they are placed in the same ranges than for similar projects. Even more, it can be stated that the results are more competitive than another Island's COE.

The differences in COE between scenario 1, based on diesel, and scenario 2, with higher penetration of wind energy are supported by the figure. As in the figure, through the simulations the wind energy-based scenario resulted in the most competitive one. The scenario 3, which implemented more PV capacity was the lee economic one, which is also supported by the table. It should be noticed that Solar Off-Grid results are remarkably high, but this is explained in the article. "The data for off-grid solar PV systems is predominantly based on aid projects and the potential for cost reductions from large-scale deployment…is significant" [73].

5. Future challenges and limitations

Through this section the constraints that have limited the project have been pinpointed in order to later define future projects that could complement the present one.

5.1 Limitations

The main limitation of the project was the used software, and are summarized below:

- Although Homer Pro is a benchmark for energy balance and electrical optimization, it does not go into detail of the power quality parameters delivered by the system generators, nor the grid architecture. Therefore, the technical requirements analyzed in Section 3 could not be tested in the simulation.
- In respect the energetic balance, Homer Pro is not capable of adding capacity in between the simulated period of a multiyear scenario. This means, that for a 25 year simulation, the initial installed capacity must be able to supply the electrical demand the year 25 of the simulation. In cases where the demand does not increase within the years, it might not be a problem, but when it does, it forces the user to dd since the beginning extra generation.
- Regarding the input data, the common limitations were the costs of DG systems, as for big equipment it is not possible to easily obtain quotation.

5.2 Future Challenges

Concerning the standards and regulations, future works could analyze the defined steps for testing that the installed DG systems comply the technical requirements from Section 3. Most regulations have specific clauses and procedures for this, and a global comparison could be done.

Other base that this project has settled for future studies is the analysis of the technical requirements extracted in Section 3 applied on the studied Island. The most economical scenario that was obtained, the 50% renewable, could be now tested to conclude if from the power quality perspective, it is feasible. This section will go further in the recommendations, and suggest the software were this task can be performed. Recently, DigSilent has released a new software, the GridCode. This new program is capable to perform a Power Quality Assessment [74], and the delivered power by any of the devices on the grid can be extracted. It also has another relevant feature for this topic, the compliance module, which is used for the verification of the response of renewable or conventional power plants during and after external events or perturbations like voltage dips (LVRT), voltage swells (HVRT), active or reactive power steps, etc. It checks through the perturbations if the Generating Units comply with the following Country specific requirements: Australia, China, Denmark, Germany, South Africa, Spain, UK, and US, which expect for South Africa, have been all considered in the paper.

6. Conclusions

In this paper, it has been proven that the challenges that currently restrain DG to replace the traditional Power System have not yet been overcome.

On the one hand, the Power Quality issues associated with an increase of DG System penetration across the distribution network have already been thoroughly considered by many standards across the globe, which is the first step for a further implementation. However, a new issue has arisen, the critical uncorrelation between the different standards, as the set parameters for the technical requirements greatly vary among the 37 studied regulations. This has an important effect, as for example a company designing PV systems will encounter difficulties in selling its products across different countries, as generally each country has very different requirements. Therefore, there is an urgent need for harmonization between organizations that issue this standard, it is in their hands now to make DG more competitive. The standard harmonization issue has already been considered in Europe for the transmission network, and for it the ENTSO-E was created in 2009, with the aim of establishing closer cooperation across Europe TSO and acting as focal point for all technical requirements.

On the other hand, through the electric planification of San Cristobal it has been possible to demonstrate that further renewable penetration in DG Systems is not only energetically feasible, but also economically. The study case has also provided the vision that DG will not achieve its full potential until the power storage technologies are brought a step forward. Regarding San Cristobal Island, the current trend in the demand will force the Island to enlarge the installed capacity in the coming years, and the Scenario 2 suggested in this paper could be used as a reference. It has proved to be the most economical one and reduced the environmental impact that pollution possess about a half in respect the current configuration.

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Annex A: Glossary

LV: Low Voltage

MV: Medium Voltage

HV: High Voltage

DG: Distributed Generation

DRE: Distributed Renewable Energy

GHG: Green House Gas

DSO: Distributed System Operator

AC: Alternate Current

DC: Direct Current

PCC: Point of Common Coupling

THD: Total Harmonic Distortion

PV: Photovoltaic

NDZ: Non-Detectable Zone

ROCOF: Rate Of Change Of Frequency

LoM: Loss of Mains

COE: The levelized cost of energy

NPV: Net present Value

Annex B: Standard Summaries

All references for the Annex are included in Table 2 of the main body.

G59: RECOMMENDATIONS FOR THE CONNECTION OF GENERATING PLANT TO THE DISTRIBUTION SYSTEMS OF LICENSED DISTRIBUTION NETWORK OPERATORS

G59 is a standard deployed in Great Britain which covers the connection of any form of generator device to run 'in parallel' or 'synchronized' with the mains electrical utility grid. It is the standard used in the UK, together with the G83, delivered by the Energy Networks Association.

It describes a simplified connection procedure for connection of a Type Tested single Generating Unit of less than 17kW per phase or 50kW three phase, or the connection of multiple Type Tested Generating Units with a maximum aggregate capacity of less than 17kW per phase or 50kW three phase, per Customer installation, provided that any existing connected Generating Units are also Type Tested. It is applicable to DG systems with a current per phase greater than 16 A, if lower, G83 applies.

G83: RECOMMENDATIONS FOR THE CONNECTION OF TYPE TESTED SMALL-SCALE EMBEDDED GENERATORS (UP TO 16A PER PHASE) IN PARALLEL WITH LOW-VOLTAGE DISTRIBUTION SYSTEMS

It is an industry standard applicable in Great Britain along the G59. It applies to Small Scale Embedded Generators (SSEGs) in parallel with public low-voltage distribution networks. This Engineering Recommendation only specifies the connection requirements applicable to those SSEG installations that are designed to normally operate in parallel with a public distribution network. Those installations that operate in parallel with the DSO's Distribution System for short periods (ie less than 5 minutes) or as an islanded installation or section of network are considered to be out of scope.

For the purposes of this Engineering Recommendation a SSEG is a source of electrical energy rated up to and including 16 Ampere per phase, single or multi- phase, 230/400 V AC. This corresponds to 3.68 kilowatts (kW) on a single-phase supply and 11.04 kW on a three-phase supply.

To implement the regulation, DG systems are classified under two stages:

- Stage 1 – a single unit within a single customer's installation
- Stage 2 – multiple units in a close geographic region, under a planned programme of work

GB/T 19964: TECHNICAL REQUIREMENTS FOR CONNECTING PHOTOVOLTAICPOWER STATION TO POWER SYSTEM

The GB/T 19964-2012 is China's standard for connecting photovoltaic power stations to the power system. Applicable for systems connected via 35 kV-and-above voltage grid, 10 kV voltage level and Hzblic grid.

IEC 61727: PHOTOVOLTAIC (PV) SYSTEMS – CHARACTERISTICS OF THE UTILITY INTERFACE

The IEC 61727 is an International Electrotechnical Commission standard. It applies to utility-interconnected photovoltaic (PV) power systems operating in parallel with the utility and utilizing static (solid-state) non-islanding inverters for the conversion of DC to AC.

The systems ruled by the standard must be under 10kVA, single or three phase. There is no current limit.

IEEE 1547: STANDARD FOR INTERCONNECTING DISTRIBUTED RESOURCES WITH ELECTRIC POWER SYSTEMS

IEEE Std 1547.2-2008 is an standard delivered by the Institute of Electrical and Electronics Engineers. The IEEE fosters the development of standards that in many cases become national regulations.

The IEEE 1547 considers the performance, testing, safety considerations, maintenance and operation requirements for DG systems. It does not differentiate between the typo of generator.

The maximun aggregate capacity considered is 10MVA

OFFICIAL INDIA GAZETTE NO 12/X/STD(CONN)/GM/CEA: DISTRIBUTED GENERATION NOTIFICATION INDIA

The following notification from India's Ministry of Power is the technical Standard for Connectivity of the Distributed Generation Resources , published on 4th April 2012. The file reference is No.12/X/STD(CONN)/GM/CEA, and was included in the Gazzete of India.

The standard is applicable to all DG systems connected to the distribution system, (less than 33kV).

UL 1741: INVERTERS, CONVERTERS, CONTROLLERS AND INTERCONNECTION SYSTEM EQUIPMENT FOR USE WITH DISTRIBUTED ENERGY RESOURCES

This standard is provided by Underwriters Laboratories, a private company accredited by ANSI as an audited designator. It is applicable in the United States and Canada.

These particular standard covers inverters, converters, charge controllers and interconnection system equipment intended for use not grid-connected and connected.

For systems that are grid-connected, the requirements in this standard shall be supplemented by the IEEE 1547.

UNE EN 206007: REQUISITOS DE CONEXIÓN A LA RED ELÉCTRICA PARA INVERSORES

The UNE 206007 is a report created by AENOR, which is a private association, acknowledged as national normalization organism in Spain.

It is important to mention that this is a a report, not an standard. The scope of the paper is to provide the minimum requisites that inverters shall provide when connected to the national grid. Some requisites refer to international standards, while some others have been introduced through this report.

The report establishes different requirements for:

- GROUP 1: Inverters where PCC is in LV.
- GROUP 2: Inverters where PCC is in HV.

EN 50438: REQUIREMENTS FOR MICRO-GENERATING PLANTS TO BE CONNECTED IN PARALLEL WITH PUBLIC LOW-VOLTAGE DISTRIBUTION NETWORKS

This standard is applicable for each of the 34 CEN-CENELEC member countries. It “carries with it the obligation to be implemented at national level by being given the status of a national standard and by withdrawal of any conflicting national standard"

This European standard is applicable to any generator connected in the low-voltage distribution network irrespectively its source of energy.

VDE-AR-N 41052: POWER GENERATION SYSTEMS CONNECTED TO THE LOW-VOLTAGE DISTRIBUTION NETWORK

This is an application guide prepared by the VDE, a technical-scientific association which develops technical regulations as national (Germany) and international standards.

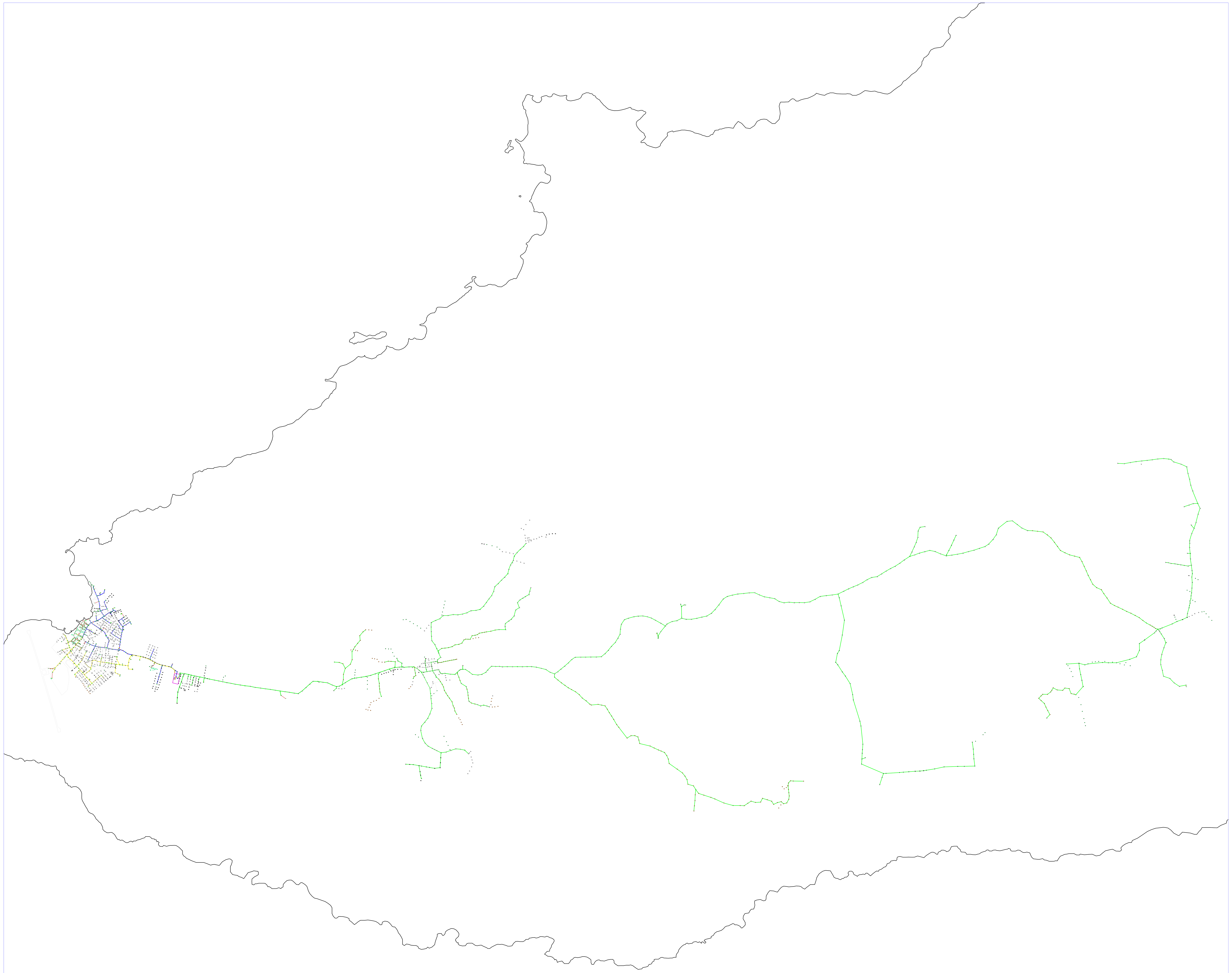
The guide applies to the planning, erection, operation and modification of power generation systems that are connected to a network operator’s low-voltage network and operated in parallel with this network (network connection point in the low-voltage network).

BDEW: TECHNICAL GUIDELINE GENERATING PLANTS CONNECTED TO THE MEDIUM-VOLTAGE NETWORK

BDEW Bundesverband der Energie- und Wasserwirtschaft e.V. is the German Association of Energy and Water Industries, responsible of the guideline.

The guideline applies not only to the operation of generation plants but also to the planning, construction and modification of them. The connection of the system must be in the medium voltage network for the guideline to applicable.

Annex C: One-Line Diagrams for San Cristóbal Island



SIMBOLOGIA

LINEA DE M.T. EXISTENTE	RECONECTADOR
LINEA DE B.T. EXISTENTE	
LINEA DE M.T. PROYECTADA	
LINEA DE B.T. PROYECTADA	
ACOMETIDA EXISTENTE	

TRAFOS DE DISTRIBUCION

AEREOS		
	TM	MONOFASICO
	TB	BIFASICO
1234	TT	TRIFASICO
	BTM	BANCO DE TRANSFORMADORES MONOFASICOS

PUESTO SECCIONADOR

NC	SCU	SECCIONADOR CUCHILLA
T	SCT	SECCIONADOR CUCHILLA TRIPOLAR

PUESTO SECCIONADOR FUSIBLE

NC	SF	SECCIONADOR FUSIBLE
NC	SFA	SECCIONADOR FUSIBLE CAMARA APAGA CHISPA
NC	SFT	SECCIONADOR FUSIBLE TRIPOLAR
	SFTA	SECCIONADOR FUSIBLE TRIPOLAR CON CAMARA APAGA CHISPAS
	SFUT	SECCIONADOR FUSIBLE UNIDAD DE TRANSFORMACION

TENSOR

	TTBT	TENSOR TIERRA BAJA TENSION
	TTAT	TENSOR TIERRA MEDIATENSION
	TDABT	TENSOR DOBLE MEDIA Y BAJA TENSION
	TFBT	TENSOR FAROL BAJA TENSION
	TFAT	TENSOR FAROL MEDIA TENSION
	TFDABT	TENSOR FAROL DOBLE MEDIA Y BAJA TENSION
	TPBT	TENSOR POSTE A POSTE BT
	TPAT	TENSOR POSTE A POSTE MT

ESTRUCTURA SUBTERRANEA

	PRE	POZO DE REVISION
	CAM	CAMARA

LUMINARIAS DE MERCURIO

	HG175A	MERCURIO 175W ABIERTA AUTOCONTROLADA

ESTRUCTURA SOPORTE

HORMIGON Y FIBRA DE VIDRIO		
C9	PHA9	POSTE DE H.A. 9m
C11	PHA11	POSTE DE H.A. 11m
C11	PMV11	POSTE METALICO. 11m
C11	PFV11	POSTE FIBRA DE VIDRIO. 11m
MADERA		
	PMT9	POSTE DE M.T. 9m
	PMT11	POSTE DE M.T. 11m

ABONADOS

30		ABONADO EXISTENTE
30		ABONADO NUEVO
		NO SOLICITA SERVICIO

LUMINARIAS

LUMINARIAS DE SODIO		
	NA70A	SODIO DE 70W ABIERTA
	NA70C	SODIO DE 70W CERRADA
	NA70AA	SODIO DE 70W ABIERTA AUTOCONTROLADA
	NA70CA	SODIO DE 70W CERRADA AUTOCONTROLADA
	NA100CA	SODIO DE 100W CERRADA AUTOCONTROLADA
	NA100C	SODIO DE 100W CERRADA
	NA150C	SODIO DE 150W CERRADA
	NA150CA	SODIO DE 150W CERRADA AUTOCONTROLADA

MISCELANEO

	PTEMT	PUENTE MEDIA TENSION
	PTEBT	PUENTE BAJA TENSION
	FRMT	FIN RED DE MEDIA TENSION
	FRBT	FIN RED DE BAJA TENSION
	AMORT	AMORTIGUADOR
A.P	CAP	CONTROL DE ALUMBRADO
F	CAPF	CONTROL DE ALUMBRADO CON FOTO
R	CAPR	CONTROL DE ALUMBRADO CON RELE

PROYECTO PMD 2014
SECCIONAMIENTOS DE
LINEA SAN CRISTÓBAL

REALIZADO: ING. ROBERTO ROBLES R.	RECOMENDADO:
REVISADO: ING. CESAR PATIÑO ROMAN	APROBADO: ING. MARCO SALAO BRAVO PRESIDENTE EJECUTIVO
FECHA: 20-03-2013	ESCALA:

SIMBOLOGIA

LINEA DE M.T. EXISTENTE	RECONECTADOR
LINEA DE B.T. EXISTENTE	
LINEA DE M.T. PROYECTADA	
LINEA DE B.T. PROYECTADA	
ACOMETIDA EXISTENTE	

TRAFOS DE DISTRIBUCION

AEREOS	
TM	MONOFASICO
TB	BIFASICO
TT	TRIFASICO
1234 BTM	BANCO DE TRANSFORMADORES MONOFASICOS

PUESTO SECCIONADOR

NC SCU	SECCIONADOR CUCHILLA
SCT	SECCIONADOR CUCHILLA TRIPOLAR

PUESTO SECCIONADOR FUSIBLE

NC SF	SECCIONADOR FUSIBLE
NC SFA	SECCIONADOR FUSIBLE CAMARA APAGA CHISPA
NC SFT	SECCIONADOR FUSIBLE TRIPOLAR
SFTA	SECCIONADOR FUSIBLE TRIPOLAR CON CAMARA APAGA CHISPAS
SFUT	SECCIONADOR FUSIBLE UNIDAD DE TRANSFORMACION

TENSOR

TTBT	TENSOR TIERRA BAJA TENSION
TTAT	TENSOR TIERRA MEDIATENSION
TDABT	TENSOR DOBLE MEDIA Y BAJA TENSION
TFBT	TENSOR FAROL BAJA TENSION
TFAT	TENSOR FAROL MEDIA TENSION
TFDABT	TENSOR FAROL DOBLE MEDIA Y BAJA TENSION
TPBT	TENSOR POSTE A POSTE BT
TPAT	TENSOR POSTE A POSTE MT

ESTRUCTURA SUBTERRANEA

PRE	POZO DE REVISION
CAM	CAMARA

LUMINARIAS DE MERCURIO

HG175A	MERCURIO 175W ABIERTA AUTOCONTROLADA

ESTRUCTURA SOPORTE

HORMIGON Y FIBRA DE VIDRIO		
C9	PHA9	POSTE DE H.A. 9m
C11	PHA11	POSTE DE H.A. 11m
C11	PMV11	POSTE METALICO. 11m
C11	PFV11	POSTE FIBRA DE VIDRIO. 11m
MADERA		
	PMT9	POSTE DE M.T. 9m
	PMT11	POSTE DE M.T. 11m

ABONADOS

30	ABONADO EXISTENTE
30	ABONADO NUEVO
	NO SOLICITA SERVICIO

LUMINARIAS

LUMINARIAS DE SODIO	
NA70A	SODIO DE 70W ABIERTA
NA70C	SODIO DE 70W CERRADA
NA70AA	SODIO DE 70W ABIERTA AUTOCONTROLADA
NA70CA	SODIO DE 70W CERRADA AUTOCONTROLADA
NA100CA	SODIO DE 100W CERRADA AUTOCONTROLADA
NA100C	SODIO DE 100W CERRADA
NA150C	SODIO DE 150W CERRADA
NA150CA	SODIO DE 150W CERRADA AUTOCONTROLADA

MISCELANEO

	PTEMT	PUENTE MEDIA TENSION
	PTEBT	PUENTE BAJA TENSION
	FRMT	FIN RED DE MEDIA TENSION
	FRBT	FIN RED DE BAJA TENSION
	AMORT	AMORTIGUADOR
A.P	CAP	CONTROL DE ALUMBRADO
F	CAPF	CONTROL DE ALUMBRADO CON FOTO
R	CAPR	CONTROL DE ALUMBRADO CON RELE

PROYECTO PMD 2014
SECCIONAMIENTOS DE
LINEA SAN CRISTÓBAL

REALIZADO: ING. ROBERTO ROBLES R.	RECOMENDADO:
REVISADO: ING. CESAR PATIÑO ROMAN	APROBADO: ING. MARCO SALAO BRAVO PRESIDENTE EJECUTIVO
FECHA: 20-03-2013	ESCALA: