Polynesian Pathways to a Future Without Electricity Grids

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Contents

1. Introduction 6
    1.1. Outline 8
2. The common characteristics of electricity systems 9
3. Research questions and methodology 12
    3.1. Question 1: Is solar practical? 12
    3.2. Question 2: Is solar economic? 13
    3.3. A note regarding data 14
4. Polynesia and Polynesian electricity systems 15
    4.1. Samoa 16
    4.2. Tonga 21
    4.3. Cook Islands 27
5. Is solar practical? 33
    5.1. Solar potential 33
    5.2. Technology status: Residential, commercial and utility scales35
    5.3. Summary of existing projects and lessons learned 36
    5.4. Lessons learned/challenges 36
    5.5. Local challenges 39
    5.6. Distributed solar/battery versus centralised solutions 40
6. Is solar economic? 43
    6.1. The levelised cost of generating electricity approach 43
    6.2. Trends in PV costs 45
    6.3. Solar and battery technology price trends 46
    6.4. Distributed battery solution examples 48
    6.5. Grid parity 49
    6.6. Methodology 49
    6.7. Trends in balance of system costs 51
    6.8. Stranded assets 53
7. Results 55
    7.1. Scenarios and assumptions 55
    7.2. Spreadsheet model and results 55
    7.3. Summary of results and comments 69
8. Conclusion 70

Appendices

Appendix A Hawaii solar initiatives 71
Appendix B References 75

Figures

Figure 1 Polynesia's place in the Pacific 7
Figure 2 Electricity systems are the same world-wide 11
Figure 3 Samoa 16
Figure 4 Upolu electricity demand profile 18
Figure 5 The islands of Tonga 22
Figure 6 The electricity demand profile varies by season and day of the week 25
Figure 7 Electricity tariff 27
Figure 8 The many islands that make up the Cooks 28
Figure 9 Electricty demand profile for Rarotonga 30
Figure 10 Daily solar radiation in Rarotonga 34
Figure 11 Hourly solar radiation, Rarotonga 34
Figure 12 Solar radition, horizontal surface 35
Figure 13 Shading 39
Figure 14 Integration costs 43
Figure 15 Total system costs 44
Figure 16 Global installed PV capacity 46
Figure 17 Cost of solar panels 47
Figure 18 Prices of residential solar power continue to fall 47
Figure 19 Prices of batteries are dropping rapidly 48
Figure 20 Grid parity has been achieved already 49
Figure 21 Tonga: Dry-season electricity demand profile 50
Figure 22 Solar radiation model for Fiji 51
Figure 23 System generation to grid balance 56
Figure 24 System generation to grid balance 58
Figure 25 System generation to grid balance 59
Figure 26 System generation to grid balance 61
Figure 27 System generation to grid balance 62
Figure 28 System generation to grid balance 64
Figure 29 System generation to grid balance 65
Figure 30 System generation to grid balance 67
Figure 31 System generation to grid balance 68

Tables

Table 1 Renewable-energy targets for small island states 6
Table 2 Renewable and non-renewable sources of electricity 9
Table 3 Main features 15
Table 4 Installed diesel fleet 15
Table 5 Installed renewable capacity 16
Table 6 Electricity generation in Samoa by source 17
Table 7 Customer types in Samoa 18
Table 8 Electricity customers in Samoa 19
Table 9 Tariffs 19
Table 10 Tariffs 25
Table 11 Electricity sales between consumer sectors for 2012 26
Table 12 Electricity pricing in Tonga, in local currency 27
Table 13 Tariff structures (as of 1st July 2011) 31
Table 14 Completed renewable projects 38

Table 15 Comparison of options for location of distributed solar and battery systems 42
Table 16 LCOE of solar electricity generation – without battery storage 44
Table 17 PV-system costs...45
Table 18 Specifications for a single Tesla Powerwall battery pack. 52
Table 19 Lead-acid batteries...52
Table 20 Costs of diesel generation in Sub-Saharan Africa 53
Table 21 Costs of diesel generation in Kenya 53
Table 22 Stranded asset costs 54
Table 23 Key system and economic metrics..56
Table 24 Key system and economic metrics..57
Table 25 Key system and economic metrics..59
Table 26 Key system and economic metrics..60
Table 27 Key system and economic metrics..62
Table 28 Key system and economic metrics..63
Table 29 Key system and economic metrics..65
Table 30 Key system and economic metrics..66
Table 31 Key system and economic metrics..68
Table 32 Summary of financial returns 70
Table 33 Credit for exporting to the grid...72
Table 34 Hawaiian Electric Company feed-in tariffs 72
Table 35 Features of KIUC Electricity Business...74

Executive Summary

Pacific Island states have committed to ambitious targets to reduce their reliance on fossil fuels to generate electricity. The Cooks Island's commitment is to have 100% renewable generation by 2020, Samoa is also targeting 100%, but by 2025, and Tonga is seeking to generate 50% of its electricity from renewable resources by 2020. As a result, large-scale renewable generation facilities are being constructed.

In these three states, at least on main islands, electricity is generated in centrally located power stations and then distributed via lines to users. The renewable generation capacity is delivered via these networks.

If current trends in the price, efficiency and capacity of distributed electricity generation continue, then in time it may be possible for electricity distribution networks to become redundant: low-cost solar panels, combined with high-capacity batteries, will be able to generate and store all the electricity needs of some consumers, especially at the household level.

The New Zealand Institute for Pacific Research commissioned NZIER, the University of Auckland and Nexgen Energy Solutions to prepare a report on the impact of renewable energy on electricity grids in Polynesia.

This first report contains the first stage of this project, which is desk-based research conducted in New Zealand on whether distributed generation has the technical and economic potential to replace distribution networks. If that potential exists, then further study of the impact of such systems on grids is justified. This first stage can be likened to a "proof of concept": if we find sufficient evidence of potential, then completing all of the research and asking the main research question – the potential impact on grids – is more than just a theoretical exercise.

We find variable, but positive, net present values for a range of different types of solar installations. These positive results will get better as technology improves and the costs of solar and batteries continue to decline. These results signal economic potential. If investment were to occur and these economic returns were realised, island communities would benefit from sustainable renewable sources of electricity, protecting their economies from uncertainties related to movements in international oil prices and unreliable shipping.

We consider that these results justify further analysis in the three states in question. This analysis will allow more detailed assessments of the possible effects on existing distribution grids.

1. Introduction

Using renewable energy to expand access to affordable, reliable and clean energy in the Pacific is a now priority for governments in the region and is a flagship investment priority of New Zealand's current aid programme. Renewable-energy targets feature prominently in all their nationally determined contributions submitted under the Paris Agreement on climate change.

The renewable-energy targets of the small island states of the Pacific are ambitious by world standards.[1] As the right-hand column in Table 1 shows, some countries already generate a large proportion of their energy needs from renewable sources.

Table 1 Renewable-energy targets for small island states

Polynesian states in **bold**.

Country	Target Percentage of energy from renewable sources, unless otherwise stated	Target date	Renewable share of power generation, 2016 (with current projects completed)
Cook Islands	100%	2020	15%
Fiji	90%	2030	65%
Kiribati	45% reduction in fossil-fuel energy generation	2025	10%
Marshall Islands	20%	2020	<1%
FSM	30%	2020	5%
Nauru	20% increase in efficiency	2015	3.2%
Niue	80%	2025	13%
Papua New Guinea	No target in place	–	50%
Palau	45%	2025	2.3%
Samoa	100%	2025	50%
Solomon Islands	20%	2020	5%
Tonga	50%	2020	13%
Tuvalu	100%	2020	43%
Vanuatu	100%	2020	29%

Source: MFAT 2016.

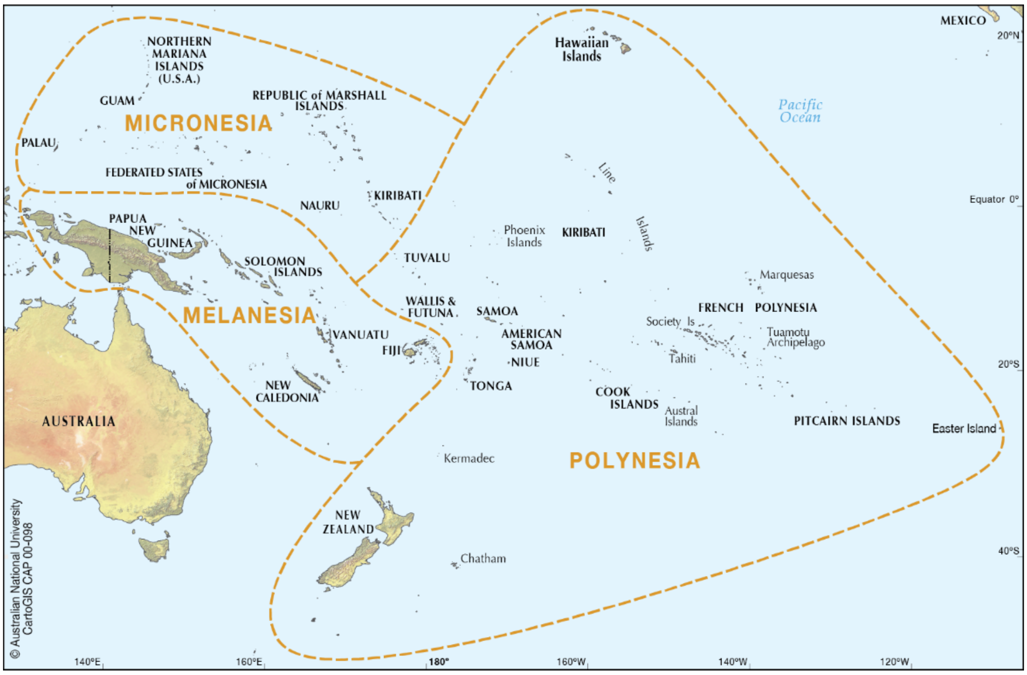
In Polynesia,[2] especially on the main islands, electricity grids are common, fed by oil-based generators. Renewable-energy sources, including the on-going investment in solar generation, are being fed into the existing grid.

[1] For example, in 2015, the 29 countries of the European Union, on average, produced 28.3% of their final electricity consumption from renewable sources (European Commission, 2017).

[2] This study is concerned with developing small island states, and thus Cook Islands, Kiribati, Niue, Samoa, Tonga and Tuvalu. Excluded are New Zealand, Hawaii and Rapa Nui.

Technological developments in small-scale electricity generation (solar panels) and storage (batteries) are challenging the assumptions underlying the operation of electricity grids across the world. Up until now, economies of scale in generation made it economical to incur the up-front costs of large generators and a grid, rather than a plethora of small, inefficient, generators close to where electricity is consumed (homes, businesses, community facilities, etc.). The cost effectiveness of other uses of electricity, like electric vehicles, is also increasing and this may result in increased demand for electricity (while reducing demand for petroleum).[3] These developments will require new thinking.

Figure 1 Polynesia's place in the Pacific



Source: CartoGIS Services, College of Asia and the Pacific, The Australian National University

Existing research has concentrated on the economics of meeting renewable-energy targets, with a focus on generation sources (oil v solar), with the technology of electricity distribution taken as given[4] and using distributed generation to provide electricity to people currently without electricity. We are not aware of any research that has looked at the consequences of renewable generation on existing grids in the Pacific when the technology of distribution is *not* a given.

Grid-based, centralised generation systems covering large areas, have remained stable for many years. Currently, solar power is being used in Polynesia to augment generation, with the view to meeting high renewable energy targets. There has been less discussion, if any, on the implications for existing electricity grids (outside the systems needed to feed variable solar power into a grid).

[3] While electric vehicles might seem like "first world" technology, apart from cost they have considerable attraction in the Pacific: running costs are low and they can be powered by renewable energy without the need to introduce other capital. For example, biofuels grown and refined in a country would require large investment and have high environmental footprints. Importing biofuels would replace one form of imported fuel with another and would have little impact on fuel self-sufficiency.

Just as Pacific people have adopted many other technologies (the internal combustion engine, cell phones, computers), we see no intrinsic reason why electric vehicles will not be added to this list, if they become economically viable.

[4] See for example: Doran (2014) and World Bank (2008).

There are two aspects to this. The first is the implication for **new consumers** of electricity, who currently can either use the grid, or deploy costly, inefficient (and polluting) stand-alone diesel generators. They may soon have the choice to go “off grid” using stored renewable energy. One important question here is whether such generation would hamper or augment the roll-out of electric vehicles.[5]

From a whole-of-country perspective, the question is whether expanding existing generation capacity and the grid continues to be economic, or whether meeting new demand from distributed generation is viable and economic.

The second, which is also being faced by infrastructure owners in the rest of the world, is the implications for **existing consumers** who are connected to the grid. They too may soon have the option of switching to distributed generation. This raises the issue of **sunk assets** in the existing grid. That is, there may be insufficient revenue from remaining customers to continue to meet the costs of the assets, especially if they were financed by borrowing. There is also the possibility of a “death spiral”: as more consumers move off grid, the cost of the existing grid must be recovered from a reducing population of consumers, leading to higher costs, which in turn makes it economic for more users to switch. Thus, technological developments which, on their face seem positive – lower costs, better access to reliable electricity – can come with other costs when the existing electricity systems are considered.[6] How should the benefits and costs be shared?

1.1. Outline

The remainder of this report proceeds as follows.

As essential background to the study, in Section 2, we discuss the features that are common to electricity systems the world over and how this is changing with the changes in the cost of renewable energy and storage. We also discuss current and future developments in solar generation and storage, both conceptually, and in the context of Polynesia.

The research question and methodologies that we have employed are set out in Section 3.

Section 4 describes the three countries with which we are concerned; Samoa, Tonga and the Cook Islands. We discuss the geography and economy of each country and provide an outline of each country’s current electricity system.

Section 5 looks at the advantages of solar power and battery storage of existing systems in use in Polynesia.

The cost of solar power is the subject of Section 6. We describe a methodology for determining costs and then apply it to the Pacific.

Section 7 contains the main analytical results of our research. We have used available data to populate an existing model that calculates the likely costs of distributed solar power in a number of scenarios, based on actual conditions in Tonga, Samoa and the Cook Islands.

Section 8 concludes.

[5] The roll-out would be hampered if, compared to a grid-based approach, distributed generation did not have sufficient capacity to meet demand for an electric vehicle as well as other uses.

[6] Examples include the costs of integrating new technology into existing networks, sunk costs if new technology supersedes existing equipment and cost of retraining staff to work on new systems.

2. The common characteristics of electricity systems

Electricity is the globally dominant source of non-transport energy for households and firms, especially in the developed world.

Electricity needs to be generated: except for lightning, it does not occur in nature. Until recently, generation for domestic and commercial purposes was almost exclusively achieved by spinning a coil of wire inside magnets,[7] using technology developed in the 1800s by Faraday, Edison, Tesla and others.[8] Generation of this type needs a fuel to power the spinning coil.

Thermal power stations use heat to generate steam that powers turbines for this purpose. Common types of thermal stations are those fired by fossil fuels (coal, oil or gas); geothermal stations that use heat generated in volcanic fields; and nuclear power stations that use heat generated in a controlled nuclear reaction to create steam that powers a turbine. Wind energy uses the kinetic energy of wind to turn a turbine, while hydroelectric stations use the kinetic energy of falling water as the power source.

A totally different system for generating electricity applies the "photoelectric effect," for which discovery Einstein was awarded the Nobel Prize in 1921.[9] The photoelectric effect is the phenomenon that light falling a metal surface will, under certain circumstances, produce electricity.

Whether generation irretrievably consumes the energy source leads to another classification system: renewable v non-renewable.

Table 2 Renewable and non-renewable sources of electricity

Renewable	Non-renewable
Solar	Coal
Wind	Gas
Wave	Oil
Geothermal	Nuclear

Source: US Energy Information Administration

All electric systems include three elements: generators, which produce the electricity; wires that move the power to the final element; and load.

[7] The operating principle of electromagnetic generators was discovered by Michael Faraday in 1831 and 1832. Electricity was first distributed to provide lighting, in competition to gas. The development of appliances and machines that used distributed electricity came later. Edison and Tesla, amongst others, devised competing systems for large-scale generation and distribution of electricity. Edison switched on the world's first distribution system on 4 September 1882, supplying 59 customers in lower Manhattan. Edison's system used low-voltage direct current (DC) generated in small stations to supply a localised network. Tesla's alternating current (AC) system, which he licenced to the Westinghouse Electric Company, involved high-voltage transmission, with transformers (which Tesla invented) used to step up voltage for transmission and then to step it down for use in premises. In the end, the Westinghouse AC system became the global standard.

[8] The other common source of electricity is batteries, which use various chemical effects to generate power. Some types of batteries can be used to store electricity that has been generated by an external source.

[9] Einstein published his results in the 1905 edition *of Annalen der Physik*, under the title: "Über einen die Erzeugung und Verwandlung des Lichtes betreffenden heuristischen Gesichtspunkt." An English-language version, "Concerning an Heuristic Point of View Toward the Emission and Transformation of Light", was published in the *American Journal of Physics* in 1965. Central to the paper was the idea that light has the dual property of both a wave and a particle (the photon).

A combination of technical requirements and economics has produced the modern electricity systems that are in use throughout the world. The major technical developments occurred in the late 19th century in the United States and Europe.

Some of the important technical features of electricity that have had strong influences on the development of modern systems are:

- Supply and demand must be matched continuously: any sudden change in either (say a boost in demand[10] or a drop in supply, for example through a power station failing, can cause the whole network to fail).
- Different loads require different voltages. While households currently all use a common voltage (230v in New Zealand), many commercial and industrial loads require high voltages and one wire can only carry one voltage.
- Related to this, generators that are connected to the same network must operate at the same frequency (50 hertz or cycle per second, in New Zealand).
- Electricity must be at a high voltage, much higher than is either required or safe at the point of use, to be carried long distances.

The combination of large generators, which are subject to economies of scale, linked together into a national grid, and transformers that can convert the voltage of the power transmitted, is what has developed. The schematic diagram in Figure 2 shows how modern electricity systems work. The starting point is the generators, which tend to be placed near fuel sources (coal fields, hydro dams, thermal fields and windy hills), rather than close to population centres.

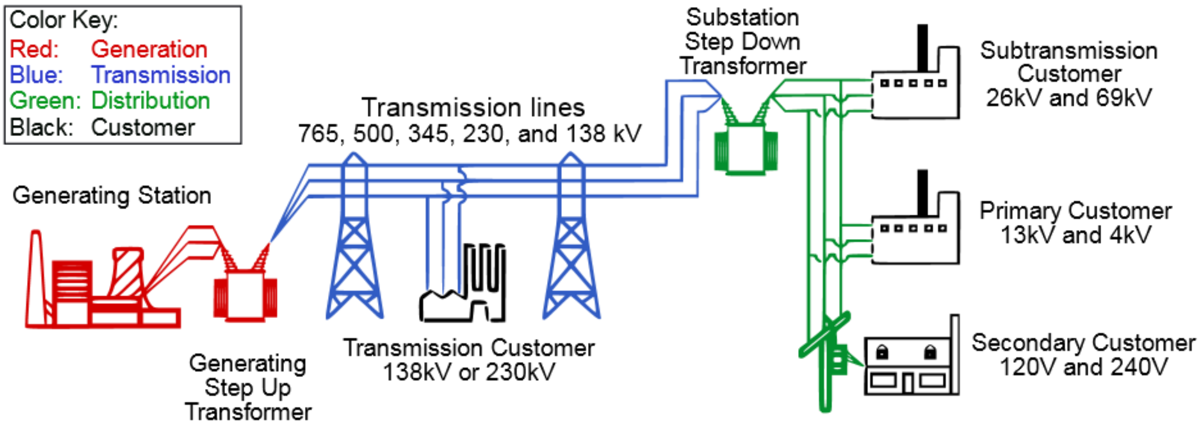
In New Zealand, there are multiple generation stations, located across the country, that are all connected to the national grid. Near each generator is a step-up transformer, that converts the power generated to high voltage (220 kv in New Zealand), which allows it to be sent long distances over Transpower high-voltage networks. Some very large commercial facilities (like the aluminium smelter at Bluff) are connected directly to the high-voltage network.

Most consumers, however, need lower voltage power and thus, closer to end users (normally in towns and cities), the electricity again passes through transformers and is stepped down in voltage. Line losses, from generation to consumer, in the order of 10% are common, depending on transmission distance.[11]

[10] One common example is the "TV Pickup" experienced in the United Kingdom when large numbers of people watching the same TV programme simultaneously use appliances at the end of the show or during commercial breaks. The caricature of millions of people making a cup of tea at the end of an episode of Coronation Street is true and must be planned for.

[11] Line losses are the energy that is used up in the process of transmitting power across distance. This is most commonly in the form of heat: transmission wires become heated as current passes through them.

Figure 2 Electricity systems are the same world-wide



Source: United States Department of Energy

3. Research questions and methodology

Our overall research question is: What are the implications of feasible developments in distributed generation to those Polynesian countries that currently have extensive electricity grids in place?

In this report, we have divided this overall question into two parts:

- Is solar practical?
- Is solar economic?

We outline the research objective and methodologies we have used, in turn, below.

3.1. Question 1: Is solar practical?

3.1.1. Research objective

To evaluate the technical potential of substituting fossil-fuel-based electricity generation with solar power, integrated battery storage and potential energy management technologies.

3.1.2. Method

Step 1

Use research of existing studies and/or electricity industry data sources to establish annual electricity usage profiles for representative scenarios, for each sector of the economy (industrial, commercial, household). Factors to be included in determining the scenarios for each sector include:

- Population (high, medium and low growth)
- National income (high, medium and low growth)
- Seasonal climate patterns
- Energy efficiency trends.

Both quantitative (hourly kWh) and qualitative (understanding of contributing load types) will be established.

Power quality, reliability/security of supply and critical/backup power and service levels will be considered as part of this step.

***Outcome*:** profile definition of representative electricity usage scenarios.

Step 2

Undertake detailed modelling of each scenario to provide understanding of the technical application of solar PV and battery storage as a substitution of existing fossil-fuel-based generation. Considerations of sizing, location of energy resources within the network and the level of requirement for fossil-fuel-based backup will be considered.

The modelling will apply annual, hourly load (as identified in Step 1), solar radiation and temperature data. In addition, the potential to integrate energy management solutions, to shift or to reduce loads to optimise solar PV and battery system requirements, will be evaluated.

***Outcome*:** technical understanding of solar PV, battery storage, backup generation and energy management systems required to support the identified electricity usage scenarios.

Step 3

Summarise findings to provide input to a cost-benefit model (see Stage 2).

***Outcome*:** provision of required inputs into an Excel-based cost-benefit model for exploring and evaluating investment options and pathways for implementation.

Step 4

Define the implementation specifications of the solar PV and battery systems required with regards to occupancy area, life-cycle maintenance/replacement and environmental considerations.

***Outcome*:** Implementation specifications that will inform the cost-benefit model and identify practical considerations for deployment.

3.2. Question 2: Is solar economic?

3.2.1. Research objective

To evaluate the economics of substituting grid-distributed generation with distributed solar power.

3.2.2. Method

Step 1

Describe existing electricity systems in each Polynesian developing small island state. Provide a benchmark overview of the costs associated with existing systems of generation, distribution networks, tariff structures, and projected costs of sustaining a fossil-fuel-based system of power generation.

***Outcome*:** status description of existing power generation systems.

Step 2

Undertake a comprehensive review of the literature on the economics of solar and battery storage systems (including role of electric vehicles).

Current and existing experience with the adoption of renewable energy in the Pacific will be incorporated into the review. The review will capture trends in solar and battery technology, economies of scale (if any), distribution infrastructure, and associated costs. Identification of appropriate technology will draw on the work of technical specialists working on the project.

***Outcome*:** up-to-date review of the costs of solar and battery technology, and its application to the Pacific.

Step 3

Combining the findings from Steps 1 and 2, evaluate the economics of off-grid generation in Polynesia.

Benefit estimates will be based on the costs avoided from reliance on a distribution grid delivering fuel-based electricity; cost estimates will be drawn from the literature reported in Step 2.

Step 3 will necessarily involve input from the technical specialists and link with an assessment of potential pathways for implementation. Depending on the budget, site-specific case studies could form the basis for evaluation.

***Outcome*:** Excel-based cost-benefit model for exploring and evaluating investment options and pathways for implementation.

3.3. A note regarding data

This report is on desk-based research undertaken in New Zealand. We have therefore had to rely on published information and data, most of which was obtained via the Internet. While we have endeavoured to find the most up-to-date information, there are in some cases gaps in what is possible. This is especially the case regarding details of the current state of electricity systems at the level of projects. The next stage of the project, which is conditional on funding, will involve more detailed case studies of the three states we are examining, including on-site research that will, it is hoped, allow a more up-to-date picture to emerge.

4. Polynesia and Polynesian electricity systems

This study focuses on three Polynesian states: Samoa, Tonga and the Cook Islands. While these states have much in common, they were selected for study because of their differences across three features (see Table 3):

- Population: Samoa's population is about ten times that of the Cook Islands.
- Total and average electricity demand.
- Penetration of renewable generation and targets.

Table 3 Main features

	Samoa	Tonga	Cook Islands
Population	193,000 (2016)	104,000 (2015)	19,000 (2016)
Annual electricity demand [MWh]	134,200 (2015)	48,000 (2014)	33,000 (2016)
Average electricity demand per person (estimate) [kWh/yr]	594	447	1,749
Total diesel capacity [MW]	43.5 Upolu 6.6 Savai'i	16.8	10.36 Rarotonga
Peak demand [MW]	18.5 Upolu 2.8 Savai'i	9.5	4.4 Rarotonga
Share renewable (2016)	50%	13%	15%
Target % renewable (year)	100% (2017)	50% (2020)	100% (2020)

Source: Mofor et al. 2013; ADB 2018.

Diesel generation is a major source of electricity in all three countries, although Samoa has the highest current penetration of renewable energy, which means that its reliance on diesel, at 50%, is the lowest of the three countries.

Table 4 Installed diesel fleet

	Samoa	Tonga	Cook Islands
Total diesel capacity [MW]	16.59	14.44	11.04
Number of units	15	19	24
Unit size, min [MW]	0.045	0.056	0.025
Unit size, max [MW]	3.5	1.729	2.1
Oldest unit start year	1979	1972	1990
Newest unit start year	2001	1998	2009

Source: IRENA 2013.

Samoa currently has relatively large hydroelectric generation capacity, and solar energy is increasingly being used in all three countries.

Table 5 Installed renewable capacity

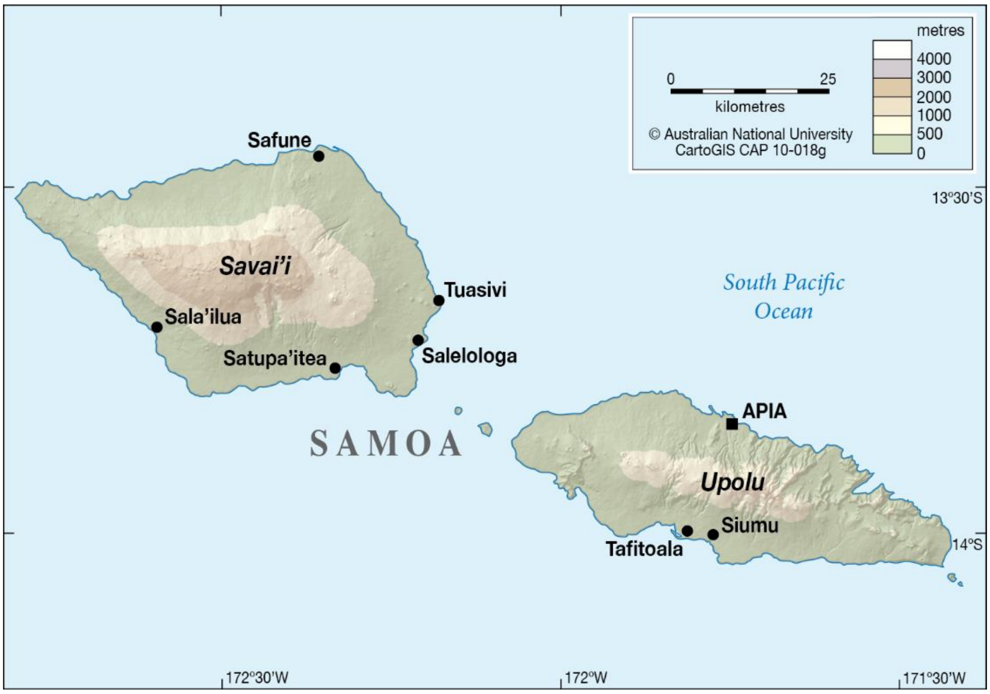
	Samoa	Tonga	Cook Islands
Solar capacity [MW]	7.20	3.282	
Wind capacity [MW]	0.55	0.011	
Hydro capacity [MW]	12.51	–	

Source: http://resourceirena.irena.org/gateway/

We now turn to discuss each individual country in more detail.

4.1. Samoa

Figure 3 Samoa



Source: CartoGIS Services, College of Asia and the Pacific, The Australian National University.

4.1.1. Geography and population

Samoa has two main islands, Savai'i and Upolu, which account for 58% and 38% of the total land area of 2,934 km^2, respectively. The population in the 2011 Census was 187,820, with an average growth rate of 0.8% per year, and an urban growth rate of 1.5% per year. Twenty-two per cent of the population resided in the Apia urban area (Upolu), 30% in the populated coastal areas on north-west Upolu, and 24% in the remaining areas of the island. Most of the remaining 24% live in Savai'i, mainly in coastal villages. Apart from emigration, there is considerable migration into Apia and the northwest of Upolu from the rest of the country. The coastal zone, which is home to about 70% of the population and most of the energy infrastructure, is vulnerable to natural hazards such as tsunamis. Only about 4% of the coastline is resilient to coastal hazards.

4.1.2. Economy

Samoa's economic growth has been steady with gross domestic product (GDP) per capita growing some 3.3% per year in real terms in the last decade until the recent global economic crisis and natural disasters impacted the economy of the country. In 2009, a devastating tsunami struck the southern coast of Upolu. Recovery required large expenditures, disrupting not only those directly affected, but the entire Samoan economy. The Asian Development Bank (ADB) estimates Samoa's GDP at about 2,109.0 million Tata in 2016 (about NZ$ 1,190 million). The economy is heavily dependent on private remittances and investment through official transfers, with as much as 25% of GDP coming from overseas remittances, mostly from Samoans living in Australia, New Zealand and the USA.

Tourism is becoming an increasingly important part of the economy providing up to 25% of GDP. Other industry is limited. Agricultural products provide about 90% of all exports and about 65% of the labour force is involved in agricultural sector. Samoa is also in the cyclone belt of the South Pacific and the aftermath of storms includes loss of crops and costly repairs to buildings and facilities.

4.1.3. Overview of current energy system

For Samoa in 2011, 65% of households reported fuelwood as their main cooking fuel, ranging from 28% in Apia to 87% in Savai'i. In addition, kerosene, LPG, electricity and charcoal were also reported as main cooking energy sources. Ninety-seven per cent of households use electricity for lighting, the rest mostly use kerosene.

The principal island of Upolu has around 23% of electricity generated from hydro. The Samoan Electric Power Corporation (EPC) has eight small hydroelectric plants ranging between 950 kW–2,000 kW (mostly run-of-river) at five locations totalling 9.71 MW of capacity. Other electricity for Upolu and the other islands is mainly generated from diesel (with a small percentage – around 3% – generated from solar).

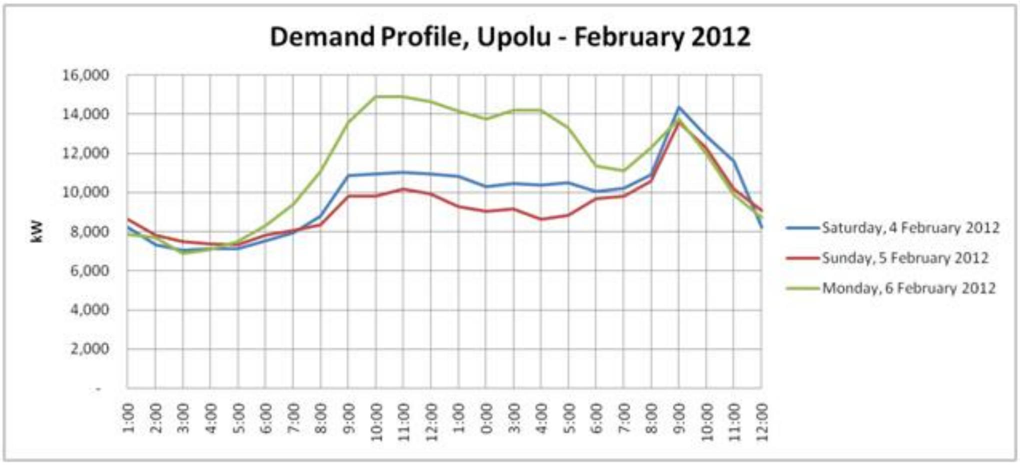
Table 6 Electricity generation in Samoa by source

Island	Source	Generation (kWh)	Proportion
Upolu	Diesel	84,853,938	64.07%
	Hydro	30,897,622	23.33%
	EPC Solar	3,359,578	2.54%
	IPP Solar	662,147	0.50%
	Wind	178,700	0.13%
	Total	***119,951,985***	***90.57%***
Apolima	Solar	11,103	0.01%
Savai'i	Diesel	12,209,014	9.22%
	Solar	261,913	0.20%
	Total	***12,470,927***	***9.42%***
Grand Total		**132,434,015**	**100%**

Source: EPC Annual Report 2014/15.

4.1.4. Upolu electricity demand profile

Figure 4 Upolu electricity demand profile



Source: IRENA 2013b.

Key features of the Upolu demand profile are:

- A commercially driven daytime peak during weekdays
- Off peak (overnight load) is 40% of peak load
- A weekend residential peak between 8pm and 11pm.

The smaller Savai'i demand profile (see Table 7) does not have the same commercial load characteristics but is dominated by residential load with evening peaks 8–11pm in the wet season and 7–11pm in the dry season.

Table 7 Customer types in Samoa

Customer Segment	Consumption – Upolu (MWh)	Consumption – Savai'i (MWh)
Residential	21,281	3,402
Commercial	40,783	4,519
Government	8,018	932

Source: EPC Annual Report 2014/15.

4.1.5. Samoa customer segments and tariffs

In 2011, EPC had 36,785 meters in operation, of which 86% were in domestic households accounting for an average of around 100 kWh per month and over 40% of all sales. Of the residential meters, 11,294 were standard units read monthly and 20,497 were pre-paid meters. Commercial users had 4,267 standard meters and 543 pre-paid meters.

Table 8 Electricity customers in Samoa

Customer segment	Total users
Domestic	31,168
Commercial	3,446
School	283
Government	402
Hotel	39
Religion	1,041
Industrial	52

Source: EPC Annual Report 2014/15

Diesel prices influence Samoa's electricity tariffs which are 0.85 to 1.0 WST/kWh (US$0.33 to 0.39).

Table 9 Tariffs

Consumer type		Tariff (WST/kWh)	Pre-paid tariff (WST/kWh)
Residential	0–50 kWh/month	0.85	0.84
	> 50 kWh/month	1.01	0.99
Commercial	All usage	1.01	0.99

Source: IRENA 2013b.

Up to 50% of Upolu's electricity is generated from hydro, the rest of supply is generated mainly from petroleum fuels. Most recent estimates (2011) show 98% of Samoa's households were considered electrified. The remainder are mostly located too far from distribution lines for grid extension to be economical. Those areas are therefore being considered for solar home systems.

Samoa's public streetlights, the majority of which are 80-watt LED lights, are not metered. EPC is continuing implementation of its US$100 million Power Sector Expansion Project (PSEP) – funded by the ADB, the Australian Agency for International Development (AusAID) and the Japan International Cooperation Agency (JICA) – through its Project Management Unit. Sub-projects being carried out as part of PSEP include building a new 20-MW diesel power station, burying transmission lines underground in the town area, and installing pre-payment meters.

EPC has eight small hydroelectric plants (950 kW–2,000 kW, mostly run-of-river) at five locations on Upolu totalling 9.71 MW of effective capacity, although dry-season hydro capacity is approximately 4.2 MW. The utility also has about 18.5 MW of diesel de-rated to 16.9 MW. Overall, the de-rated dry-season capacity of all systems is about 21 MW of which 81% is diesel and 19% hydro. The peak Upolu load in 2011 was around 16.2 MW. In Savai'i all generation is diesel, with 6.6 MW of nameplate capacity de-rated to 5.8 MW, and peak demand at 2.8 MW.

Electricity demand in Savai'i was roughly 8.9 MWh in 2011, and is split between the commercial (51%), residential (38%) and the government (11%) sectors. Data for Upolu are available only for the years 2005 to 2009, during which electricity demand decreased from 82 MWh to 70 MWh. This is partly explained by the tsunami of 2009, which destroyed a major portion of infrastructure on the south coast of the island. The commercial sector consumed 58% of this, the residential sector 30% and government 11%.

Electricity tariffs in Samoa have been 0.85 WST/kWh (0.47 NZ$/kWh) for low consumers (<50 kWh/month) in the residential sector and 1.01 WST/kWh (0.56 NZ$/kWh) for high consumers (>50 kWh/month). Pre-paid tariffs are 2 and 3 cents lower per kWh for low and high consumers, respectively. The commercial sector pays 1.01 WST/kWh on the regular tariff and 0.99 WST/kWh on a pre-paid tariff.

4.1.6. Electricity sector

The government has developed the Samoa National Energy Policy, which came into effect in 2007 along with the Strategic Action Plan. The Strategic Action Plan includes a goal of 20% of all energy services to be supplied from renewable energy by 2030. In 2012, the policy and its associated plan were reviewed as the first step towards the development of the Samoa Energy Sector Plan 2012–2016 and its programme of activities, which was launched in December 2012.

The Energy Policy and Coordination Division of the Ministry of Finance (MoF) is responsible for all energy planning and policy, including development and implementation of the Samoa Energy Sector Plan. The Energy Policy and Coordination Division is also responsible for monitoring, evaluation and coordination of national- and regional-level energy projects and publishing annual energy reviews.

Part of the MoF's responsibilities is also petroleum supply, and it negotiates the 5-year contract for supply and distribution of fuel from government-owned storage. The state-owned EPC reports to the Minister of Works, Transport and Infrastructure. The ADB has instituted a series of technical assistance programmes directed at capacity building and investment support, particularly with the EPC.

The energy sector plan is aimed at supporting delivery of the Strategy for the Development of Samoa (SDS) 2012–2016 which has the vision to improve the quality of life of all citizens of Samoa. Renewable energy and energy efficiency are the main components of the energy sector plan where the MoF plays a coordinating role. The implementation is carried out by various ministries and agencies such as the Ministry for Natural Resources and the Environment, the Scientific Research Organisation of Samoa and EPC as well as NGOs and the private sector. Renewable energy projects are sometimes coordinated by these agencies in relation to their own particular mandates and roles, but they are all linked to the energy sector plan, policy and programme of activities coordinated by the MoF. EPC is usually the interface for electricity-based renewable energy systems.

Development aid from New Zealand's Ministry of Foreign Affairs and Trade (MFAT) to Samoa is currently aimed at increasing renewable energy production to help Samoa achieve its renewable energy targets. MFAT supports the $NZ14.5 million programme that has installed solar array panels and will be constructing and rehabilitating hydro-power plants. Projects include three solar photovoltaic (PV) systems, one of which is currently the largest solar array in the southern Pacific, at the Faleata Racecourse in Apia. This will meet approximately 4.5% of Samoa's total electricity needs, reducing demand for imported diesel by more than a million litres per year, with annual savings of about WST 3.4 million (NZ$1.7 million).[12]

[12] MFAT, n.d.-a.

4.1.7. *Renewable energy*

In 1986, EPC electrified Safotu (on Savai'i,) with solar PV through a United States Agency for International Development (USAID) grant (International Renewable Energy Agency [IRENA] 2013b). The project installed 30 household systems, each with three 13-watt fluorescent lights. Families paid WST 200 (NZ$109) for installation and were to pay WST 10 (NZ$5.45) weekly for the service. For various reasons, including the lack of EPC support, no spare parts, insufficient training and low user payments, the systems were not sustained, and the community is now grid-connected.

In 2006, 10 households and a village church on Apolima island (a small caldera island between Upolu and Savai'i,) were electrified using the first independent solar mini-grid in the Pacific (IRENA 2013b). The system has 13.76 kW_p of panels with battery storage, which provides uninterrupted AC power supply to the island. The system has worked very well and, despite some problems with the controllers' cooling fans and the settings on one inverter, no power outages have occurred since it was commissioned.

Approximately 1,600 Samoan homes (5%) are not connected to the grid, and in 2008 a feasibility study was conducted for their electrification with various sizes of solar home systems. So far, 46 systems, donated by a Chinese company after the 2009 tsunami, have been installed in these homes. That project also provided two off-grid solar installations for government facilities and one for an NGO.

EPC currently operates three grid-connected solar power units (Greenpower, 4 MW; Sun Pacific, 2 MW; and Solar for Samoa, 4 MW; MoF, n.d.).

4.2. Tonga

4.2.1. *Geography and population*

Tonga comprises 176 islands of which 36 are inhabited. The total land area is roughly 750 km^2 spread over 700,000 km^2 of ocean. There are five main groups of islands: Tongatapu, Vava'u, Ha'apai, 'Eua and Niuas. The country has a total population of just over 103,000 (2011 Census), of whom 73% reside on the main island, Tongatapu; 15% in Vava'u; 6% in Ha'apai; 5% in 'Eua; and 1% in Niuas.

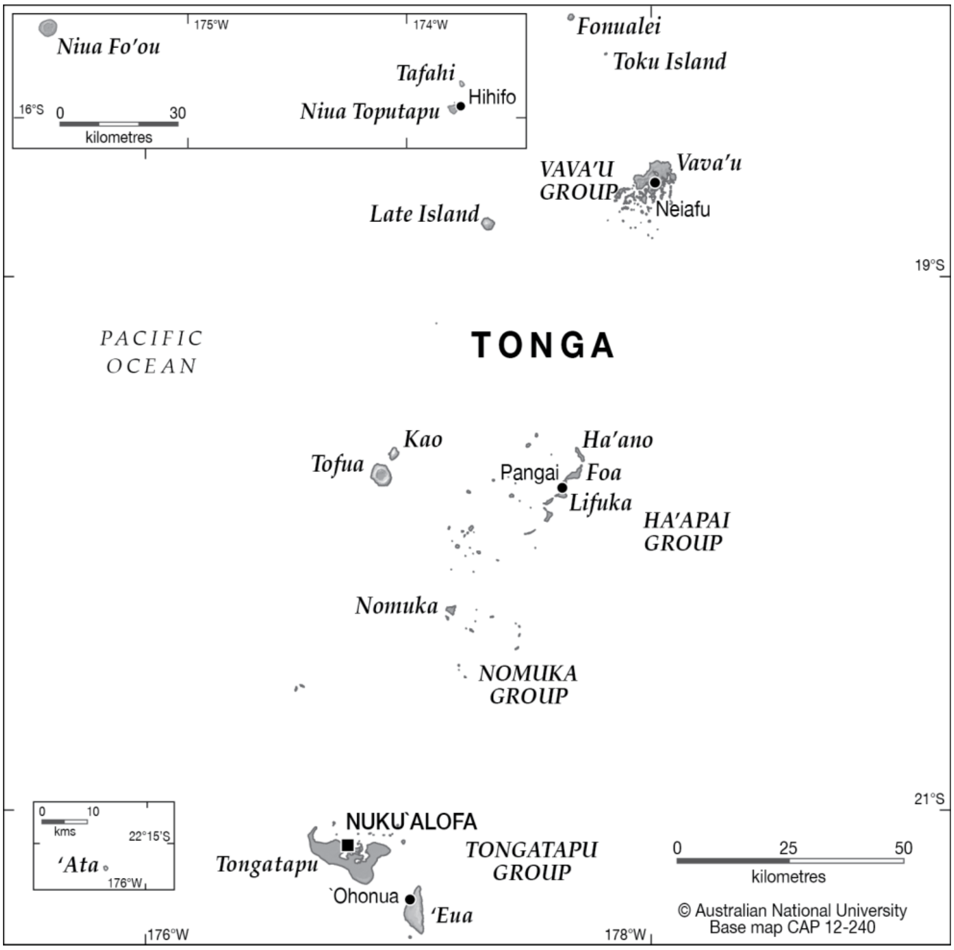
Tonga's climate is tropical with some differences between the southern and northern island groups. Cyclones are common and can cause damage to infrastructure and crops.

The Energy Planning Unit (EPU) within the Ministry of Lands, Environment, Climate Change and Natural Resources deals with energy planning, policy development and project co-ordination. The EPU was instrumental in developing rural electrification through solar energy. It is currently overseeing solar on Tonga's outer islands and also working in the area of energy efficiency in parallel with programmes being carried out under the Tonga Energy Road Map Implementation Unit (TERM-IU).

Electricity in the urban islands is provided by Tonga Power Ltd. (TPL) – a government-owned corporate entity that operates under a concession agreement monitored by the Tonga Electricity Commission, the electricity regulator. The rural areas in Tongatapu have TPL-operated diesel grids, while the outer islands have either solar power or community-managed diesel mini-grids.

In 2009, the government of Tonga approved a goal of supplying 50% of electricity from renewable energy sources by 2012. After gaining some experience and reviewing the goal, planners decided to turn efforts to increasing the efficiency of electricity generation and distribution, petroleum fuel management and electricity end use, which was seen as more cost-effective. Improved access to energy on the outer islands through renewable energy development was also added to the plan. The time scale for achieving the goal was extended to a more plausible deadline of 2020.

Figure 5 The islands of Tonga



Source: CartoGIS Services, College of Asia and the Pacific, The Australian National University

4.2.2. *Economy*

The economy of Tonga is also heavily reliant on remittances. Although tourism is also important, it contributes much less to the economy than remittances. Fisheries and tourism offer the best potential for economic growth, though, in the near term, agriculture is likely to remain the most important source of export earnings, contributing around 30% to GDP. The value of exports fell to less than 6% of imports in 2012. Petroleum imports accounted for about 23% of the value of all imports.

4.2.1. *Overview of current electricity system*

Well over half of Tonga's national energy needs are met by imported petroleum. Solar PV accounted for less than 4% of the total energy used in 2013, although rapid expansion has changed that figure.

During the past 5 years there has been little change in generation with demand remaining in the 40 to 44 GWh range, a result of economic stagnation and the rising cost of electricity. Load on the grid typically peaks in the early evening, reaching a total of approximately 7 MW. Solar generation is not able to address this peak without adding a substantial storage component. The daytime load changes markedly across the week with the noon peak during weekdays and Saturdays reaching 6 MW but falling to 5 MW on Sundays. This will need to be considered when increasing the level of solar connected to the grid, as the existing 1.3 MW of solar will already reach 20% grid penetration at noon on weekends, which is a level that starts to cause concerns for grid stability. Integrating solar with battery storage would address this concern. The second 1 MW of solar PV, which was installed in 2013, is several kilometres from the 1.3 MW plant and includes a form of short-term energy storage to reduce the effects of power fluctuations.

TPL generates and distributes all electricity in the islands of Tongatapu, ‘Eua, Lifuka (Ha’apai) and Neiafu (Vava’u). Small grid systems for the larger Ha’apai islands (‘Uiha, 168 customers; Ha’ano, 106; Ha’afeva, 69; and Nomuka, 110) were constructed with AusAID funding in 2001–2003. The systems are powered by diesel generators and operated by an electricity co-operative on each island. Hours of operation vary by island but typically are less than 12 hours a day. The operation cost of these microgrids has been higher than predicted, largely due to loading of the units being lower than expected, causing the engines to operate with poor fuel efficiency. An ADB project has been proposed to address the difficulty with these small grid systems and determine the feasibility of integrating solar generation so as to reduce fuel usage.

There is some private generation of electricity in the outer islands, particularly on church and commercial properties. On the outer islands, solar PV systems provide lighting for most church, school and community hall buildings.

In addition, solar home systems provide power for almost all of the homes in the smaller outer islands with the most recent installations providing 160 W of solar PV capacity. The systems, with batteries, provide 24-hour power for lighting and small communications and entertainment appliances.

In addition, MFAT fully funded the installation of solar power systems in six northern group islands in 2015 (MFAT n.d.-c). These systems meet at least 95% of the islands' energy needs, reduce diesel fuel consumption by approximately 600,000 litres/year, and reduce greenhouse gas emissions by the 1,600 tonnes/year (CO2 equivalent).

In Tonga a 1.3 MWp array at the Tongatapu powerhouse was completed in 2012 with funding from NZAID, the European Investment Bank and Meridian Energy. The plant is owned and operated by TPL. A second 1 MW solar power plant was installed in 2013 with funding from JICA. These installations would include some energy storage to help stabilise the power from the solar plant, thereby avoiding grid-stability problems.

There is a grid-connected solar installation in Vava’u, Tonga, with a 500 kW_p installation funded by the Abu Dhabi Fund for Development. Since the noon Vava’u peak load on the weekend is less than 500 kW, the installation needs to include battery storage and control technology to mitigate the effects of the variability of the solar energy. Grid-connected solar installations have also been proposed for the small grids in the Ha’apai and ‘Eua groups, though specific designs and sizes have not yet been designated.

Various private organisations have funded grid-connected solar on Tongatapu. All the installations use inverters that conform to TPL’s requirements for net metering. Over 200 kW_p of additional grid-connected solar is in the pipeline for private installation on Tongatapu.

Based on a feasibility study by the ADB, it is expected that the establishment of a grid-based power system in the Niuas will need to be subsidised in the same way as the grids on ‘Eua, Ha’apai and Vava’u. Even for solar-based electrification, the government has had to provide assistance, through the EPU, including regular refresher training for local technicians.

Tonga is heavily reliant on diesel generation. The government has a core objective to “reduce Tonga’s vulnerability to oil price shocks by increasingly accessing state-of-the art energy technologies in an affordable and environmentally sustainable manner” (TPL n.d., p. 2).

To achieve this objective, TPL must reduce its reliance on diesel generation and introduce a higher proportion of renewable energy generation. Over the 3 years to 2017, TPL increased electricity generation from renewable energy to approximately 8%, with the remaining 92% generated from diesel-powered plants. It has an objective to further reduce electricity generation from diesel engines to 50% by 2020, which is the target set by the government.

TPL has identified that it will require 15.3 MW (8.7 MW of solar and 6.6 MW of wind) in new renewable energy generation and at least 20 MWh of storage capacity installed and commissioned by 2020. It has been estimated that up to 20 seniti/kWh (current tariff price = 70 seniti/kWh – around US$0.30/kWh) electricity tariff reduction could be achieved from reaching a 50% renewable energy penetration target.

TPL has identified that it will need to raise about T$166 million (approximately NZ$92 million) to fund these projects. Funds will need to be raised either from development partners, institutional lenders or by some other means.

The electricity demand for the island groups are as shown in Table 10. The Tongatapu grid accounts for around 85% of the total electricity generated.

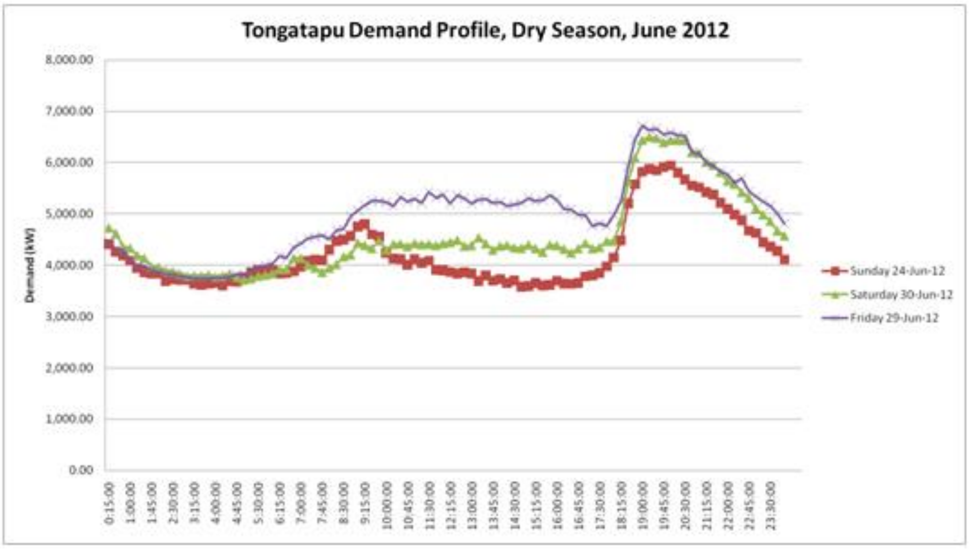
Table 10 Tariffs

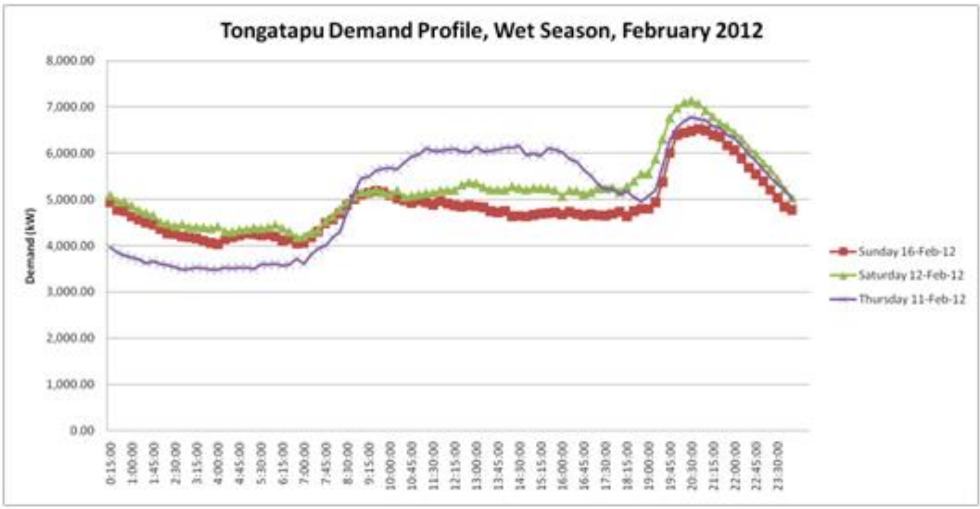
	2010	2011	2012	2013	2014	2015	2020
Tongatapu Grid	MegaWatt.hours						
Billed Energy	36,759.0	36,223.3	36,001.0	36,760.1	38,230.6	40,142.1	51,232.6
Total Losses	6,856.3	6,019.6	5,391.4	4,987.6	4,899.1	4,845.6	5,284.3
Total Generation	43,615.3	42,242.9	41,392.3	41,747.7	43,129.6	44,987.7	56,516.9
Loss as % of Gen.	15.72%	14.25%	13.03%	11.95%	11.36%	10.77%	9.35%
Peak Demand, MW	7.903	7.654	7.500	7.565	7.815	8.152	10.241
Vava'u Grid	MegaWatt.hours						
Billed Energy	4,037.0	3,978.1	3,953.7	4,037.1	4,198.6	4,408.5	5,626.5
Total Losses	756.6	666.8	600.5	570.3	557.1	560.2	663.2
Total Generation	4,793.6	4,645.0	4,554.2	4,607.4	4,755.6	4,968.7	6,289.7
Loss as % of Gen.	15.78%	14.36%	13.19%	12.38%	11.71%	11.28%	10.54%
Peak Demand, MW	1.021	0.989	0.970	0.981	1.013	1.058	1.340
Ha'apia Grid	MegaWatt.hours						
Billed Energy	1,236.5	1,240.0	1,255.4	1,294.2	1,346.0	1,413.3	1,803.8
Total Losses	168.4	165.4	160.4	162.4	168.8	175.5	217.5
Total Generation	1,404.9	1,405.4	1,415.7	1,456.6	1,514.8	1,588.8	2,021.2
Loss as % of Gen.	11.99%	11.77%	11.33%	11.15%	11.14%	11.05%	10.76%
Peak Demand, MW	0.300	0.300	0.304	0.313	0.325	0.341	0.432
'Eua Grid	MegaWatt.hours						
Billed Energy	882.1	884.6	895.6	923.3	960.2	1,008.2	1,286.8
Total Losses	194.1	182.0	162.6	146.2	142.8	140.3	163.0
Total Generation	1,076.2	1,066.6	1,058.2	1,069.5	1,103.0	1,148.5	1,449.8
Loss as % of Gen.	18.04%	17.07%	15.37%	13.67%	12.94%	12.22%	11.25%
Peak Demand, MW	0.229	0.227	0.225	0.228	0.235	0.245	0.309
Total, All Grids	MegaWatt.hours						
Billed Energy	42,914.5	42,326.0	42,105.6	43,014.7	44,735.3	46,972.1	59,949.6
Total Losses	7,975.4	7,033.8	6,314.8	5,866.5	5,767.7	5,721.7	6,328.0
Total Generation	50,889.9	49,359.8	48,420.4	48,881.2	50,503.0	52,693.8	66,277.6
Loss as % of Gen.	15.67%	14.25%	13.04%	12.00%	11.42%	10.86%	9.55%

Source: Tonga Energy Roadmap 2010–2020, Tonga Government.

4.2.2. Tonga electricity demand profile

Figure 6 The electricity demand profile varies by season and day of the week





Source: IRENA 2013c.

Key features of the electricity profile are:

- Electricity demand is 10% higher in the wet season than the dry season
- Relatively flat weekday energy profile with similar daytime and evening peaks
- High overnight base load compared to daytime and peak loads.

4.2.3. Tonga customer segments and tariffs

Table 11 Electricity sales between consumer sectors for 2012

Group	Annual consumption (MWh)
Residential	22,109
Commercial/industrial	22,448
Government	611
Total	**45,168**

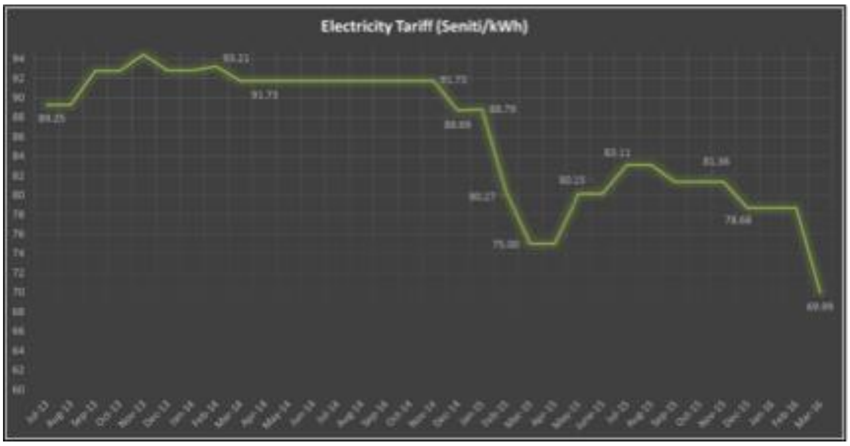
Source: Tonga Energy Roadmap 2010–2020, Tonga Government

TPL has around 17,000 residential customers and 4,000 commercial customers.

The cost of electricity to end consumers is heavily influenced by the global oil price. Over the past 3 years, the electricity tariff has varied between 93 seniti and 70 seniti/kWh.[13]

[13] 1 seniti is approximately equal to US$0.44.

Figure 7 Electricity tariff



Source: Tonga Power Business Pan 2017–2020

The fuel price accounts for 40% of the electricity tariff. The electricity tariff is reviewed several times each year and is adjusted to reflect landed diesel costs.

Table 12 Electricity pricing in Tonga, in local currency

Island	Non-fuel component	Fuel component	Electricity tariff
Tongatapu	44.35	29.64	73.99

Source: Tonga Power Business Plan 2017–2020.

4.2.4. Renewable energy

Tonga has used solar PV for household electrification in rural areas for nearly 20 years.

The first solar mini-grid in Tonga was installed in 2010 at the Fafa Island Resort off the coast of Tongatapu (IRENA 2013c). The installation was designed to supply the resort with 15 kW_p of solar panels and lead-acid batteries for storage. The diesel engine that provided power before the installation of the solar panels is now used as backup for the solar generation.

Total generation (diesel plus renewables) in all four islands groups for year ending June 2017 was about 66.5GWh. Of this, total renewable energy generation for the FY 2016/17 year was 4,823MWh, up 2.0% from the previous year (TPL 2017, p. 29). About 40% of this production comes from the Maama Mai's unit.

4.3. Cook Islands

4.3.1. Geography and population

The Cook Islands comprise 15 major islands, with a total of 236 km^2 of land, spread over an area of 2,200,000 km^2 of ocean. The total resident population was estimated at 9,556 in 2016. The northern Cook Islands are seven low-lying, sparsely populated, coral atolls; the southern

Cook Islands, where most of the population lives, consist of eight elevated, fertile, volcanic isles, including the largest, Rarotonga, with 70% of the population, at 67 km^2.

The climate is maritime tropical with a small temperature difference between day and night, and modest seasonal changes. On average, three cyclones occur every 2 years, usually between November and April.[14]

Figure 8 The many islands that make up the Cooks

[14] IRENA Cook Islands 2013, p. 2.

Source: CartoGIS Services, College of Asia and the Pacific, The Australian National University

4.3.2. Economy

Tourism is the Cook Islands' biggest export earner, making up about 60% of its GDP. More than 122,000 people visit the Cook Islands every year. The fisheries sector is a significant earner, although yet to perform to its potential or to expectations (MFAT n.d.-c). Agriculture, fishing, fruit processing, clothing and handicrafts are the remaining economic activities. About 75% of outer-island households engage in fishing, mostly for their own use, compared to just 29% in Rarotonga (IRENA, 2013a). The northern group of islands has shifted from land-based agriculture as their principal economic activity to sea-related activities, notably pearl and seaweed farming. The southern group of islands continues to grow bananas, taro and cassava. The economy of Rarotonga is largely based on trade and services, with tourism being the economic mainstay.

Like Samoa and Tonga, the Cook Islands are highly dependent on imported refined petroleum fuels, which, according to IRENA estimates, account for 90% of gross energy supply. Biomass provides most of the remaining 10%, which is mainly used for cooking. Wholesale prices of gasoline and automotive diesel oil, excluding taxes and duties, are considerably higher than average for the Pacific Islands region overall and about double those of nearby French Polynesia.

Rarotonga accounts for the bulk of electricity generation by TAU (Te Aponga Uira), the government-owned power utility for Rarotonga. Demand grew by almost 50% between 2006 and 2010, whereas some of the smaller islands had a 2–3-fold-demand growth in this period. Since 2010, however, electricity consumption has remained stable (IRENA 2013a).

By 2001, nearly 99% of all households had electricity, with 94% of them connected to an island grid; 8% had solar PV systems and 3% used small diesel generators. In the northern islands, 60% of households were connected to an island grid and 43% had PV systems.

In discussing the issues facing the outer island, IRENA has observed:

> *Outer-island electrification has been problematic since the 1970s. Excluding the largest island, Aitutaki, outer-island systems suffer from irregular fuel supply, poor fuel handling, inadequate maintenance and poor facilities. Each local government is responsible for its power system. General subsidies continue to be provided from the national government for island operations, some of which are used for electricity supply. The charge to consumers varies by island but is typically substantially higher than Rarotonga, with most suppliers not able to fully recover costs[15].*

The Cook Island's government's goal is to convert all outer-island generation to renewables by 2020, using solar mini-grids (solar PV with batteries) sized to handle 80%–90% of the required grid energy are planned, with shortfalls covered by diesel

At NZ$0.57–NZ$.84/kWh, solar and battery systems are likely to be cost competitive. In Aitutaki, the ANZ Bank has installed a 7.9 kW_p grid-connected system to offset the cost of air-conditioning. In Rarotonga, the TAU has a net-metering policy and has shown considerable interest in connecting both small wind and solar to the grid.

[15] IRENA (2013a).

4.3.3. Overview of current electricity system

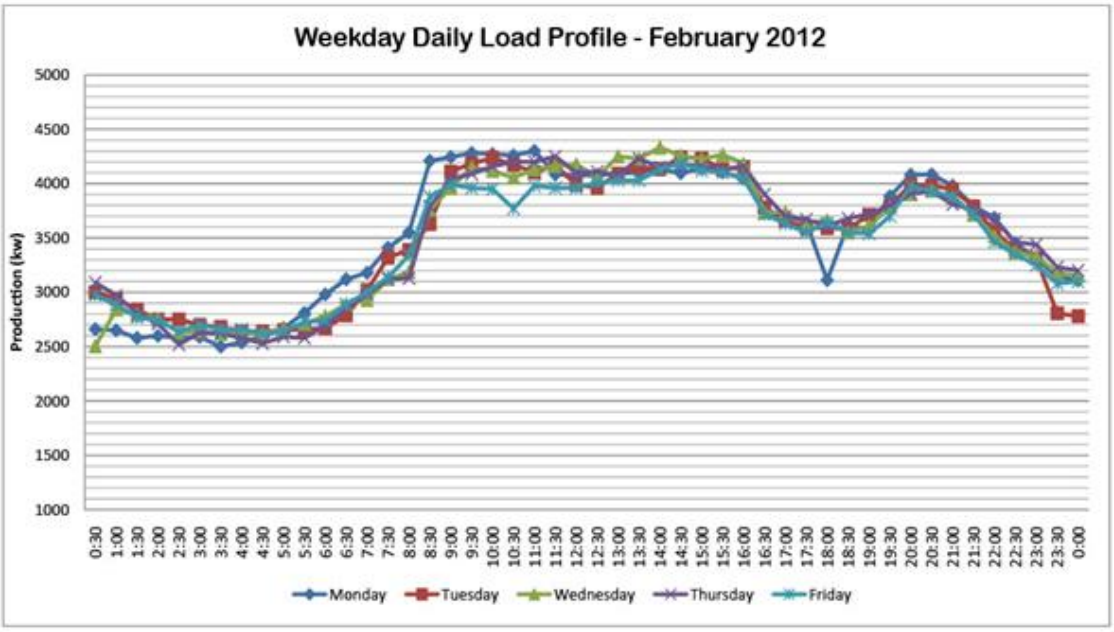
In 2011, TAU had 11 MW (continuous rated capacity) of diesel generation. Total generation exceeded 27 GWh and peak power demand was just under 5 MW.

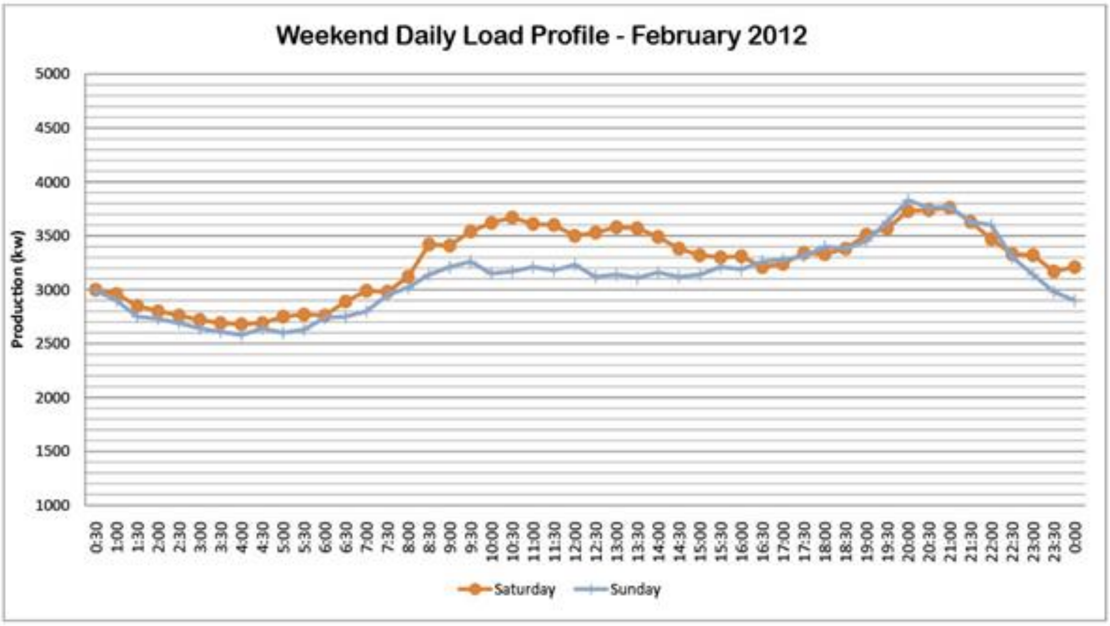
There is 3 MW of renewable generation already in the grid on Rarotonga, most of it small-scale distributed solar PV systems (e.g., domestic rooftops and small independent power producers), but also including a 1 MW solar PV plant. This provides approximately 13% of the total energy requirements on Rarotonga, which is an important contribution to the Cook Islands policy targets.

A current project is evaluating the introduction of a large centralised battery system. The proposed concept for the Rarotonga battery energy storage systems arose from an increasingly complex power system, with several system constraints and drivers. Grid-stability criteria mean that without system changes further installation of renewable generation will soon reach a stability limit. Disrupting the roll-out of renewable generation will impact on the ability to achieve the Cook Islands policy targets, as well as impacting local businesses, employment, and broader stakeholder confidence in delivery of the renewable energy policy. The Rarotonga network consumes about 90% of the total electricity demand in the country.

4.3.4. Cook Islands electricity demand profile

Figure 9 Electricty demand profile for Rarotonga





Source: IRENA 2013a.

Key features of the Rarotonga demand profile are:

- The electricity demand profiles clearly reflect contributions from the commercial sector as the daytime peak is significantly lower during weekends
- In general, there are two electricity peak demands, i.e., late morning to early afternoon and in the evening
- The decrease in commercial-sector activities in the afternoon (around 5pm) is replaced by the increase in residential-sector activities resulting in an evening peak around 8 pm.
- In general, peak demand during weekdays is 25% higher than at weekends.

4.3.5. Cook Islands customer segments and tariffs

According to the 2011 Census there were 4,391 households in the Cook Islands. Around 80% of electricity customers are domestic, the remaining are commercial.

Table 13 Tariff structures (as of 1st July 2011)

Category	Tariff (NZ$)	Tariff (US$)
Domestic		
First 60 kWh/Month	0.57	0.45
61 to 300 kWh/Month	0.80	0.63
Balance	0.84	0.67
Commercial		
All	0.81	0.64
Service Charge	5	3.97

Category	Tariff (NZ$)	Tariff (US$)
Demand		
kWh used	0.72	0.57
Peak/kW	30	23.81
Shoulder/kW	26	20.63
Service Charge	20	15.87
Dual Tariff		
First 60 kWh/Month	0.57	0.45
61 to 300 kWh/Month	0.80	0.63
Balance	0.84	0.67
Service Charge	10	7.94

Source: TAU published tariffs.

4.3.6. Renewable energy

In the Cook Islands, TAU is installing solar panels on the roof of its Atiu power house and many private investors are applying for connection under the utility's net-metering policy. As of mid-2012, over 90 private grid-connected PV systems were installed or were planned for immediate installation. About 60% of these are residential and the rest are commercial, with the average installation being about 7 kW_p. The largest is 85.2 kW_p, on a commercial building, and the smallest is 800 W_p on residences. The total number of private installations completed by April 2012 was 367.12 kW_p with another 300.56 kW_p expected to be installed by the end of 2012. The installations are distributed all around Rarotonga, but in terms of the W_p installed, capacity is concentrated in the Avarua area (IRENA 2013a).

The telecom company has installed significant numbers of PV generators, ranging from 600–7,800 W_p. IRENA reports that these installations are well-performing.[16]

Due to the variable nature of both solar energy supply and electricity demand, and consequently the required levels of diesel generation for grid stability, the share of solar power in centralised power systems is limited. Some islands, such as Rarotonga, are very close to reaching this technical limitation.

All outer islands of the Cook Islands have had, or still have, some household PV systems for lighting and radio operation. Most of these were small government pilot projects, but none of the projects included mechanisms for proper maintenance or financial sustainability (IRENA 2013a).

The largest stand-alone PV project in the Cook Islands was the electrification of Pukapuka in 1992 with finance from France. Over 46 kW_p of solar panels to electrify more than 160 household and public systems, including communal refrigerators and streetlights, were installed. The installations worked well for more than 10 years before the high-quality industrial grade batteries began to fail. Then, a cyclone in 2005 damaged many systems and put most of the installations that were still working out of service. After considering a diesel grid, the government decided that the best option was to install two solar mini-grids, as there are two population centres separated by over a kilometre.

16 (IRENA 2013a).

5. Is solar practical?

We now turn to the question of whether distributed solar electricity is a practical alternative to grid-based electricity (and if not now, then what needs to happen for it to become practical)?

5.1. Solar potential

Hourly data for a 12-month period are desirable for modelling solar and battery solutions. Radiation data have been sourced from two sources. NIWA's online tool SolarView[17] was used to retrieve hourly data for a typical day of each month of the year for Rarotonga, Cook Islands, based on 18 years of measured data. This is not available for the other islands, hence satellite-measured data from the US National Aeronautics and Space Administration (NASA) was used to get a daily average solar radiation per month and scaled accordingly using the data from Rarotonga as a base, and variation in the satellite data between the different locations (latitudes) as a scaling factor.

NASA is the only freely available source for solar radiation across all Pacific Islands, based on many years of satellite measurement data. However, the actual solar resource may be significantly different, as the islands cause local climate effects, most notably clouds due to rising air currents over larger islands.

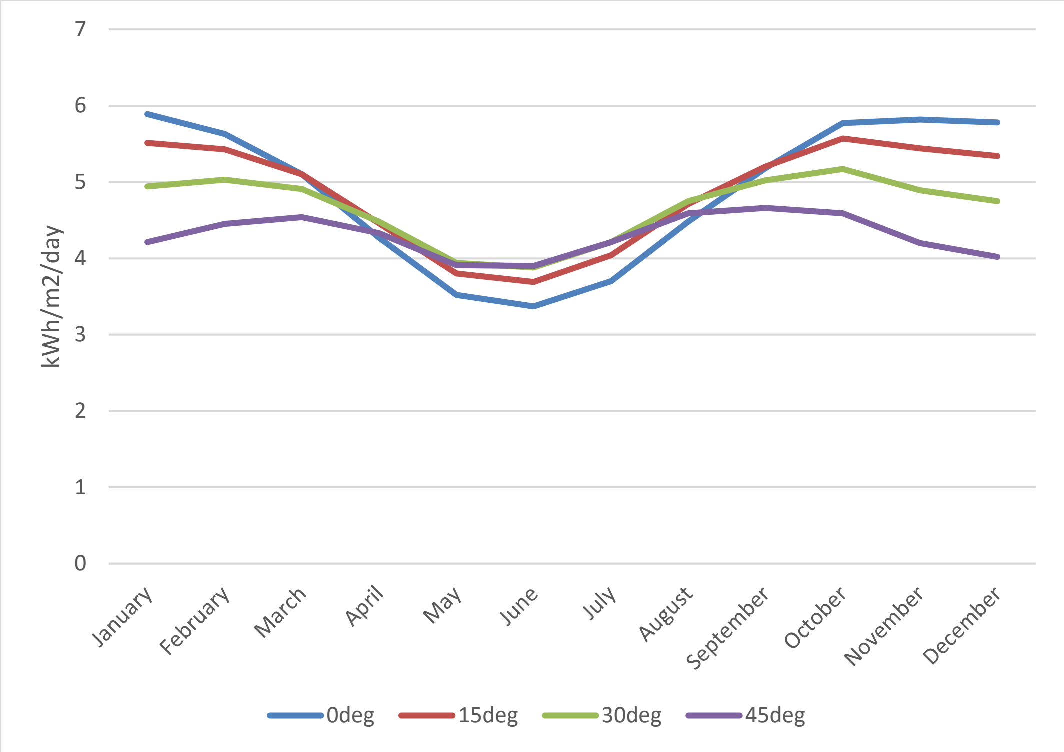
Country-specific reports from IRENA estimate the solar resource for each island individually. In summary:

- Most of Samoa receives a daily average insolation of over 5.0 kWh/m^2 with relatively small seasonal variation (IRENA 2013b).
- in Tonga, particularly towards the north, satellite measurements indicate that the daily solar insolation is as much as 5.8 kW/m^2. (IRENA 2013c).
- Cook Islands data showed that insolation, corrected for a tilted collector, has an average of over 5.5 kWh/m^2 per day. (IRENA 2013a).

In general, there is a humid, warmer period from November to April with relatively steady daily solar radiation around 5–6 kWh/m^2/day, and a drier, cooler period from May to October, with slightly lower solar radiation, about 4 –5 kWh/m^2/day.

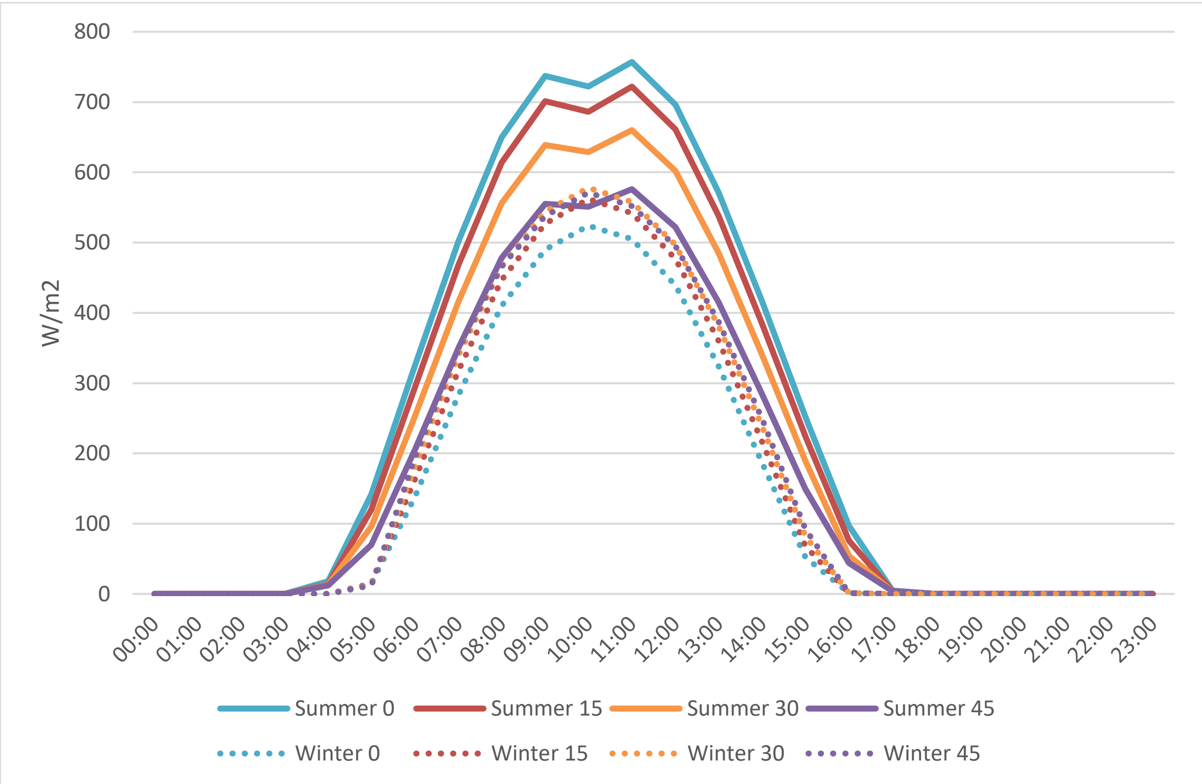
[17] https://solarview.niwa.co.nz/

Figure 10 Daily solar radiation in Rarotonga



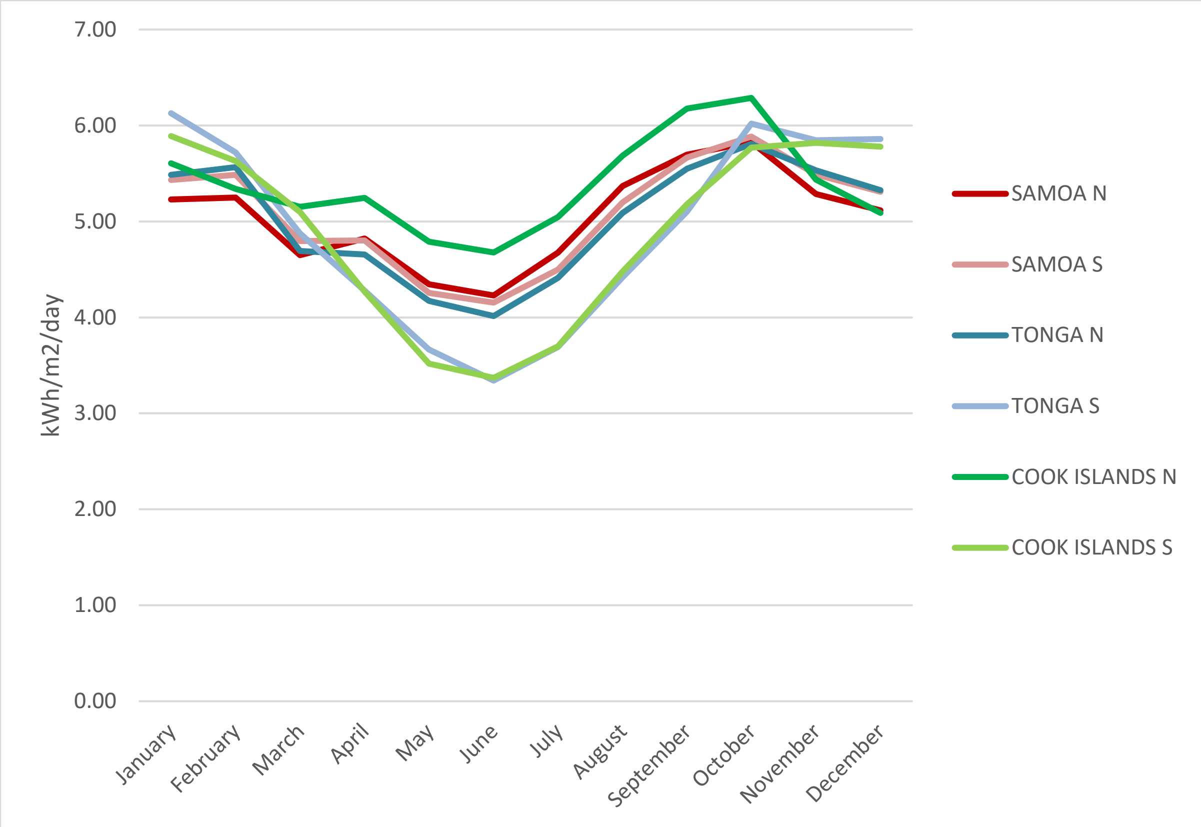
Source: SolarView, NIWA

Figure 11 Hourly solar radiation, Rarotonga



Source: SolarView, NIWA.

Figure 12 Solar radition, horizontal surface



Source: SolarView, NIWA

5.2. Technology status: Residential, commercial and utility scales

The global solar industry is dominated by c-Si cells. However, developments in 2nd and 3rd generation cells are expected to result in a change in the composition of global PV cell production over the coming decades (World Energy Council 2016). As the global PV market changes, this will have consequences for the economic returns of PV systems at all scales.

First generation, c-Si, PV cells consist of either monocrystalline (sc-Si) or multi-crystalline (mc-Si) silicon structures. The vast majority of PV systems are c-Si, with c-Si cells contributing approximately 92% of global PV production in 2014 (Fraunhofer Institute of Solar Energy 2015).

Second generation PV cells utilise thin films of amorphous silicon (a-Si:H), cadmium telluride (CdTe), or copper indium diselenide (CIS) to generate electricity. Thin film cells contributed approximately 9% of global PV production in 2014 (Fraunhofer Institute of Solar Energy 2015).

Third generation PV cells are novel technologies currently being explored or developed. Barriers currently exist preventing mass production and adoption of 3rd generation cells (IT Power Australia & Southern Perspectives, 2009). However, as the cost efficiency of third generation cells improve, novel PV-technology cell adoption is expected to increase in the future (IRENA 2012).

5.3. Summary of existing projects and lessons learned

Table 14 gives the main project details of some completed solar PV projects in the Pacific region. Capacity factors have been calculated based on the reported data on system size and annual output. Most of the projects are connected to the island grid, and simply replace part of the diesel generation with solar power. Only the smallest projects seem to be stand-alone installations with battery systems, not connected to diesel generation.

Drawing from the data available for existing projects (Table 14), the investment costs for solar power projects are still relatively high, averaging at NZ$20,600 /kW.[18] In New Zealand, current PV investment costs are around NZ$3,000–3,500 /kW.

The Pacific region has an excellent solar resource, although it can vary significantly between the islands, and even within an island, due to cloud cover (IRENA 2013d). The capacity factor is effectively a comparison of the annual output of a PV installation to the hypothetical output of the installation generating at rated/peak capacity throughout the year. The average capacity factor for the existing projects is 0.18, ranging between 0.11 and 0.25. However, the annual outputs reported may be estimates evaluated prior to the project commissioning, rather than measured data.

5.4. Lessons learned/challenges

Despite the different characteristics in urban and rural communities and electricity demand between the three island states, some common challenges and lessons learned have been identified from past projects (IRENA 2013a, 2013b, 2013c).

Regarding technical issues, all country reports mention the need for investing in components that will survive under very difficult environmental conditions. Simple but well-made equipment has a better chance of long-term survival than complicated, state-of-the-art components. The more remote the site, the greater the need for high-quality, long-life components. Advanced control systems have been shown to take a long time to repair when something fails. Systems with simple, manual controls can more easily be fixed by a local, trained person. Remote monitoring over an Internet connection may be beneficial though, if the management is centralised on another island.

Experience from the Cook Islands also found that donor-funded energy projects have tended not to be consistent with one another, resulting in a variety of different types of installations that present difficulties with maintenance and spare parts. This reiterates the importance of all systems having a consistent and standardised design approach, with as many components as possible standardised for all islands. This would make it easier to keep spare parts in stock, as international transportation by air and by sea can be unreliable and often expensive, making the delivery of replacement parts slow and costly.

In the case of Tonga, it was found that long battery life and customer satisfaction (and therefore fee payments) depend largely on having ample solar-panel capacity – oversizing panels makes good economic sense. However, there needs to be clarity between grid-based substitution, distributed solutions and grid-connected systems that reduce reliance on the grid.

Limited technical capacity of those living on the outer islands requires installations that are simple to maintain and can be monitored externally through the Internet if they are to be sustainable and reliable.

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[18] At an exchange rate of US$1 = NZ$1.38, xe.com, August 28, 2017.

Wide deployment of renewable energy systems also has its economic challenges. Despite the high fuel cost of diesel-based systems, the relative cost of renewable energy still tends to be high, particularly the initial investment, and the inter-island transportation needed for repairs is expensive.

There is an almost total dependence on donor funding for energy projects that results in long lead times and adds complexity to implementation and maintenance. Also, in some cases, the application of duties and taxes has been inconsistent for renewable energy systems, causing additional economic uncertainty.

In the case of Samoa, the cost of electricity is already relatively low, due to its hydro resources, which reduces the competitiveness of other renewables.

Consideration of institutional barriers are outlined briefly below; more detail should be obtained during Stage 2.

5.4.1. Samoa

- Renewable energy development is not the specific responsibility of any government department.
- Lack of clear roles for different agencies and weak institutional structures for energy within government.
- Lack of a realistic and well-defined action plan to implement fuel import reduction targets.

5.4.2. Tonga

- Community-based institutions are not adequate to ensure sustainable operations and maintenance (O&M). Since preventative maintenance greatly improves long-term reliability, it cannot be neglected.
- Lack of preventative maintenance on solar and lithium-ion battery systems.
- There is limited capacity for energy planning, financial planning and analysis, and project development.
- There is limited availability of energy data. Energy companies and agencies need to improve their record-keeping and data-management capacities.
- There is a lack of local training capacity in business management and renewable technologies.
- There is a lack of trained or experienced personnel for management or technical positions in energy companies, especially on the outer islands.
- There is a small and fragmented energy market, which makes it difficult to develop private energy-related businesses.

5.4.3. Cook Islands

- Integration of higher shares of solar or wind to the grid without sufficient planning and controls can result in instability and reduced quality of power.
- Dynamic modelling of the grid will be an important aid to maximising renewable energy input without compromising overall power quality.

Table 14 Completed renewable projects

Location (year installed)	Description	Capacity	Annual output	Capacity factor	Diesel annually displaced	Cost	Grid-connected
Cook Islands (2014–2015)	8 diesel-PV-battery mini-grid systems	857 kW_p	1,126 MWh	0.15	230,000 L	US$12,800,000	Mini-grids that contain diesel generation
Tonga (2012–2013)	PV	512 kW_p	866 MWh, 17% of Vava'u's demand	0.19	289,000 L		Yes
Tonga* (2011–2012)	PV	1.32 MW	1,880 MWh, 4% of Tongatapu's demand		470,000 L	NZ$7,900,000	Yes
Kiribati (2014–2015)	PV with control system	500 kW_p	885 MWh	0.20	227,000 L		Yes
Tuvalu (2014–2015)	PV with control system	500 kW_p	755 MWh, 30% of island demand	0.17	248,000 L		Yes
Tuvalu (2009)	PV-battery mini-grid (school)	46 kW_p	100.74 MWh	0.25		US$800,000	No?
Tokelau (2010–2013)	PV-diesel, on three atolls	365 kW_p 265 kW_p 300 kW_p	90% of demand		(US$760,000 saved per year)	US$6,930,000, maintenance US$42,000 per year	Yes, small grids with diesel generation
Fiji (2013)	PV mini-grid for 77 households (280 people)	20 kW_p	20 MWh	0.11	7,000 L (if fully replaced, unclear)	US$400,000, maintenance annual US$4,000	Mini-grid
Fiji (2014–2015)	3 PV-diesel systems	225 kW, 150 kW, 150 kW	820 MWh	0.18	260,000 L		Yes
Vanuatu (2014–2015)	PV	767 kW	1,240 MWh	0.18	452,000 L		Yes

Source: IRENA 2013a; IRENA 2013b; IRENA 2013c and *Meridian Energy n.d.

5.5. Local challenges

There are specific challenges to the application of solar and battery technology in Polynesia.

5.5.1. Salt corrosion

The proximity of most installations to the coast introduces special conditions for system components. While most solar panels are rated to withstand salt conditions, all fixings and other components used need to be stainless steel or anodised aluminium. This introduces some additional cost, but not significantly.

5.5.2. Temperature

Solar-panel generation figures are quoted based on a 25 °C ambient temperature. Production falls by around 0.5% for each degree above 25 °C.

Lead-acid battery life is also impacted by warm temperatures and, in some cases, installation has been undertaken underground to maintain a stable temperature.

Lithium-ion batteries are, however, less prone to life degradation from temperature (although installation out of full sun is still required) and therefore overcome some of the historic issues with installing batteries in Polynesia.

5.5.3. Cyclone conditions

Periodic cyclonic winds present requirements for structural strength of panel mounting solutions, which adds cost. This also presents potential issues for lease or "energy as a service" business models with the inherent risk to the service provider's assets.

5.5.4. Shading

Tall palm trees are a typical feature of Polynesia that provide potential shading issues for rooftop solar in residential neighbourhoods.

Figure 13 Shading

Rarotonga, Cook Islands	Nuku'alofa, Tonga	Apia, Samoa
		

Source: Google Maps

5.5.5. *Cost versus annual income*

While costs have fallen and there is a sound investment case for many customers, the up-front capital cost for many will remain a challenge.

The cost of a suitable solar and battery system for a typical household would be NZ$5,000–$10,000.

Average annual salaries, however, are:

Cook Islands	$15,028 (2011 Census)
Samoa	$22,000 (Samoa Bureau of Statistics 2017)
Tonga	$17,000 (Tonga Department of Statistics 2009)

Appropriate lease or "solar as a service" business models are therefore more likely to drive uptake versus cash sales.

5.6. Distributed solar/battery versus centralised solutions

At the centralised level, solar PV systems have been financially and environmentally justified as a replacement for diesel generation. The economics of these projects have been able to be achieved because of the economies of scale associated with large solar arrays.

With recent and on-going expected falls in the cost of solar PV and more recently battery technology, the economics of using these solutions at the individual premise or neighbourhood level to reduce reliance on grid-provided electricity may provide a financially attractive alternative.

In addition to reducing the volume required of centrally generated electricity (and therefore displacing diesel generation), there is also a reduction in the requirements for the transmission and distribution networks.

While solar PV on its own provides a means of cost reduction (grid-electricity avoidance) for property owners' daytime electricity requirements it does not represent a reliable alternative to grid electricity (due to intermittent generation levels and daytime-only energy production, which typically does not correspond to peak electricity demand). High penetration of solar PV on distribution networks leads to power quality challenges, which ultimately leads to restrictions on the volume of solar PV systems able to be connected.

5.6.1. *Property owner benefits*

- Reduced total cost of the electricity service required from the grid
- Cost surety providing a level of buffering from increasing grid-electricity costs
- Improved reliability of supply.

5.6.2. *Utility operator benefits*

- Less requirement for expensive diesel generation
- Improved power quality – voltage control and system reliability
- System resilience through diversified resources (no single point of failure)
- Higher asset utilisation through a flatter load profile

- Reduced capital requirement for both generation and network upgrades or replacements.

Distributed energy resources, however, also represent risks to the utility operator from a commercial perspective, if unforeseen and without appropriate amendments to traditional revenue and service model assumptions.

As consumers make their own investments in energy systems, the amount of revenue that will be earned by the utility will be reduced, which may lead to a higher burden being placed on other consumers, therefore incentivising more consumers to invest (the "death spiral" often referred to by analysts).

Utilities will have to consider the long-term assumptions regarding load growth and the associated requirement for investment in assets. Failure to do this could lead to stranded capital. Furthermore, utility business models will need to develop new pricing structures that incentivise customers to invest in network beneficial energy systems and demand side energy solutions. As a new business activity, all potential options need to be considered by utility operators.

This may include a review of the core architecture of electricity networks, with a move towards a system of interconnected microgrids where small distributed systems of solar and battery storage (involving a group of properties) are integrated into an overall network. This could be the best option if, for example, a battery system shared between several properties was financially the best solution.

Alternatively, having all resources at individual properties with electronics, which automatically optimises charging and discharging of batteries locally, may be the best option, as this is arguably the least complex and provides the greatest level of reliability (without a single point of failure).

Table 15 Comparison of options for location of distributed solar and battery systems

Option	Advantages		
	Generation	**Distribution**	**Customer**
			
Solar and battery storage at point of generation	Displaces expensive diesel generation	Nil	Potentially lower energy prices if the cost of energy from solar and battery is lower than diesel
Solar and battery storage sited within the distribution network, operating as interconnected microgrids	Displaces expensive diesel generation	Reduces demand on upstream network assets	Potentially lower energy prices if the cost of energy from solar and battery is lower than diesel. Potentially higher reliability if the microgrid can operate in stand-alone mode if there is an upstream network failure.
Solar and battery storage located at individual customer premises with capability to optimise solar self-consumption and peak-demand reduction	Displaces expensive diesel generation	Reduces demand on all network assets	Potentially lower power prices if the cost of energy from solar and battery is lower than the total delivered cost of energy from the network (generation and distribution) Higher reliability if the battery can support the property during a network outage

Source: Author (Gareth Williams)

6. Is solar economic?

Our second research question asks: Is solar electricity an economic alternative to grid-based electricity (and if not, when, on current trends, will it be economic)?

6.1. The levelised cost of generating electricity approach

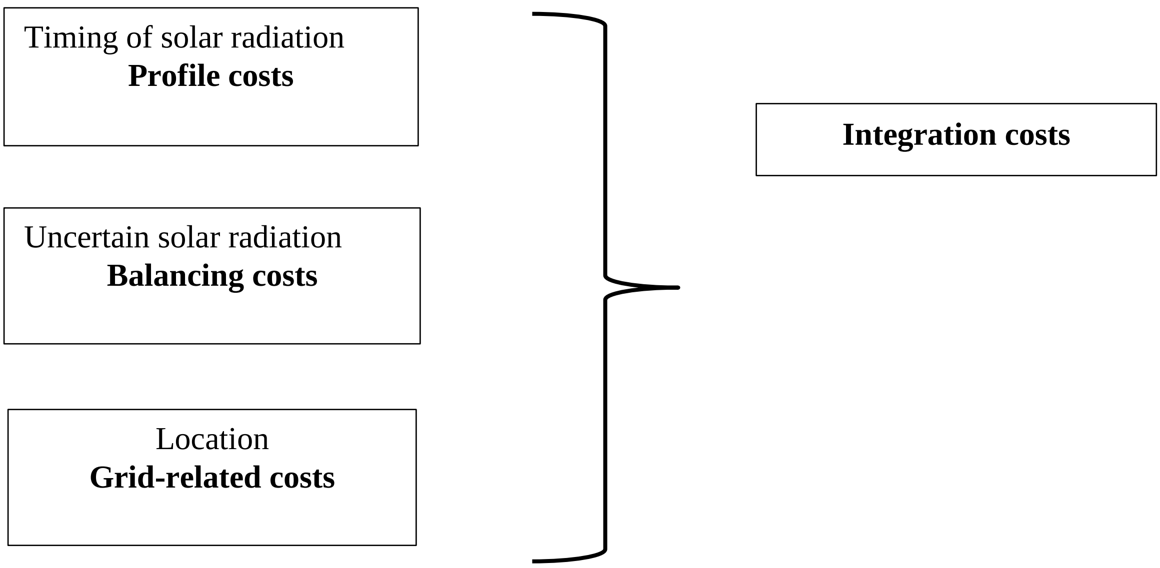
An influential paper by Joskow (2011) demonstrates the flaw of comparing renewable generating technologies (wind, solar) with conventional technologies (gas, coal) using life-cycle costs. The fundamental problem is that metrics such as the levelised cost of generating electricity (LCOE) treats electricity generated as a homogeneous product and fails to take into account the value of supply at different times of the day.

When wholesale markets are in place prices will vary according to periods of peak demand, generation profile, the season and the location of generation. There is no wholesale market in Polynesia and price variation arises from the cost of fuel. LCOE does not capture wholesale price variations (Ueckerdt et al. 2013). The economic value of intermittent and dispatchable sources of electricity is expected market value, total life-cycle costs and expected profitability.

In the absence of a wholesale market, a fixed administered price enters into the calculation of LCOE, as shown below. However, administered price does not necessarily reflect economic value.

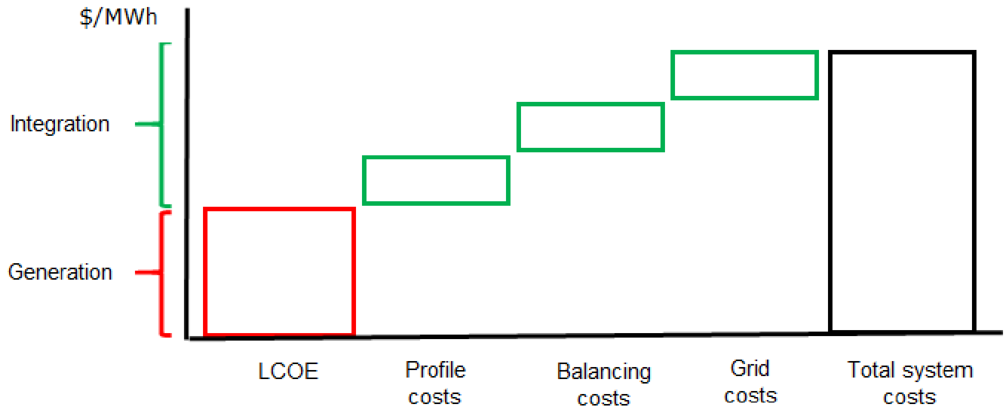
PV-system costs = cost of PV modules + balance of system (BOS) costs + costs associated with integration.

Figure 14 Integration costs



Source: Adapted from Ueckerdt et al. 2013

Figure 15 Total system costs



Source: Adapted from Ueckerdt et al. 2013

6.1.1. LCOE

LCOE provides the per-unit cost of generation (¢/kWh) by discounting all costs – investment, maintenance, fuel, and other costs associated with installing and operating a generation facility – into a present value divided by the value of energy generated over the life of the investment (Kang and Rohatgi 2016).

Capital cost, variable on-going costs, the discount rate and the quality of solar radiation combine to influence the cost of electricity generated by PV solar. Of these parameters, the cost of capital, finance, and the efficiency of solar cells are significant. According to IRENA (2012) the PV-module cost of c-Si PV is between 1/3 and 1/2 of a PV system. If the price of electricity is greater (less) than LCOE then the investment would yield a greater (loss) return on capital. Other things being equal, the higher the level of solar resource the lower the LCOE will be.

Given intermittency, solar resource can be measured as mean annual kWh/m^2/year or kWh/m^2/day. Miller at al. (2015) calculate the LCOE of solar electricity generation – without battery storage – in New Zealand (Table 16). Transmission, distribution and additional system costs were not included in their study.

Table 16 LCOE of solar electricity generation – without battery storage

Location	¢/kWh
Solar PV rooftop – Christchurch	16–24
Solar PV rooftop – commercial	14–24
Solar utility PV – utility	10–18
Energy efficiency	0–5.5

Source: Adapted from Miller et al. 2015

6.2. Trends in PV costs

6.2.1. PV-module costs

Table 17 shows the price of crystalline silicon (c-Si) modules were in the range of US$1.02–1.24/W in 2012 (IRENA 2012). Greater variability in total installed costs arises from across-country differences in input markets, such as labour, and incentives.

IRENA (2012) estimated the LCOE of residential systems without storage (assuming a 10% cost of capital) within the range US$0.25–0.65/kWh in 2011. With storage, the LCOE range increased to US$0.36–0.71/kWh. The LCOE range for utility scale was US$0.26–0.59/kWh. IRENA concludes that PV is competitive with regional tariffs in regions with good solar and cheaper than diesel generators for off-grid generation.

These estimates can change markedly with advances in solar technologies and growth in competitive markets. PV-module-efficiency improvements are possible. The average efficiency of multi-crystalline c-Si modules could approach 17%. Importantly, the cost estimates do not include additional system costs associated with intermittent supply.

Table 17 PV-system costs

Type	Module Cost (2010 US$/W)	Installed Cost (2010 US$/W)	Efficiency (%)	LCOE (2010 US$/W)
Residential				
c-Si PV system	1.02–1.24	3.8–5.8	14	0.25–0.65
c-Si + battery	1.02–1.24	5–6	14	0.36–0.71
Utility scale				
Amorphous Si (thin film)	0.84–0.93	3.6–5.0	8–9	0.26–0.59

Source: IRENA 2012, 1.

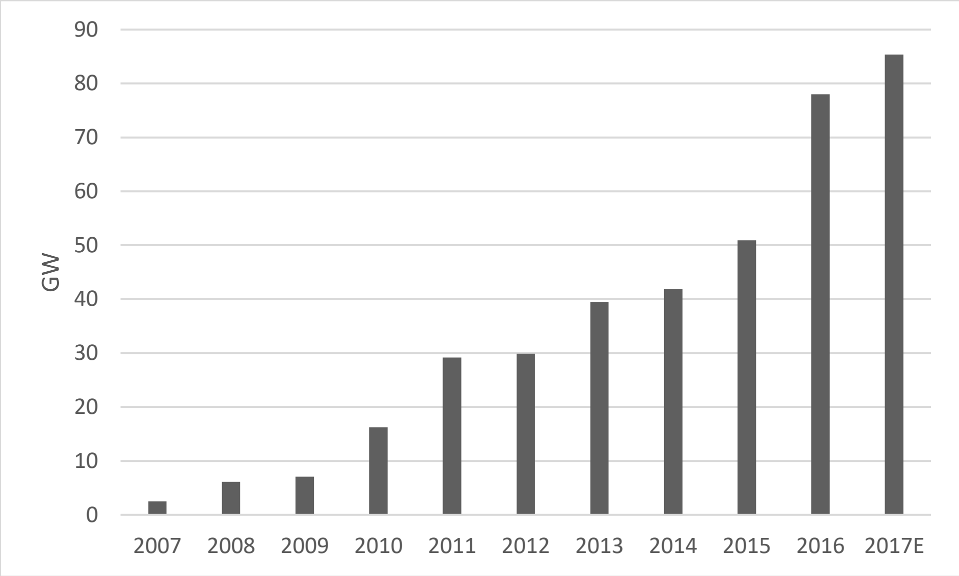
More recently, prices of PV systems have become much lower. For example, in June 2018, *PVInsights*, a US-based trade magazine, estimated average PV-module prices had fallen to $US0.278 per watt for standard multi-crystalline modules, with multi-PERC modules coming in at an average of $US0.337 per watt, and mono-PERC modules at $0.363 per watt.[19]

6.2.2. PV market trends

Global installed capacity is expected to double between 2014 (41.9 GW) and 2017 (85.4 GW), and forecast to increase to 110.1 GW in 2022. Policies actively promoting solar have driven most of this growth. China has dominated growth in installed capacity in recent years and future projections are contingent on the direction taken by the Chinese government. Changes to feed-in-tariffs and possible caps on solar expansion in China could lead to price instability in the market.

[19] PERC is short for Passivated Emitter and Rear Cell.

Figure 16 Global installed PV capacity



Source: https://www.greentechmedia.com

6.3. Solar and battery technology price trends

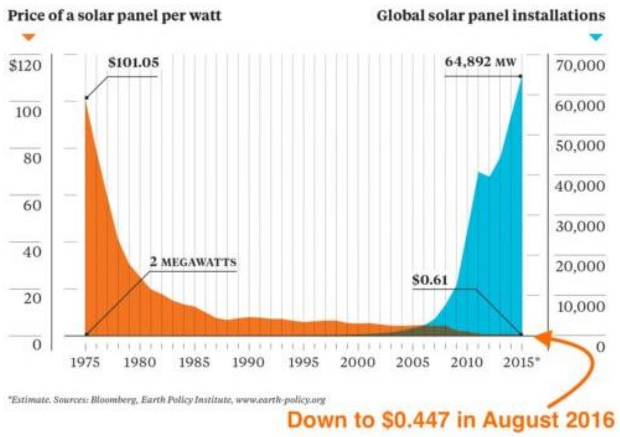
6.3.1. Costs of solar PV systems

There have been significant year-on-year cost reductions in solar PV systems, driven predominantly by the decreasing cost of solar panels.

Currently, tier 1 panel prices are at a wholesale cost of around US$0.40/W with some lesser known panel brands in the low to mid US$0.30/W.

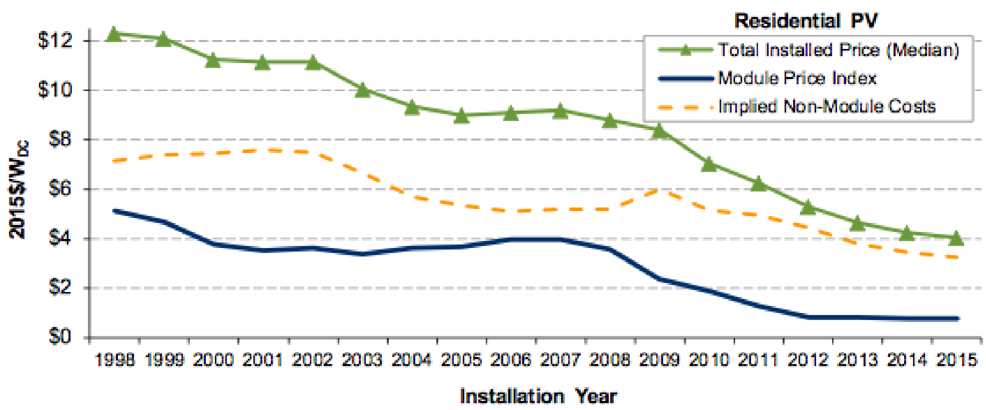
In the US, the total installed cost of solar PV has fallen at a rate of around 10% per annum since 2010, with both module price and non-module costs both reducing. (Note: US installed costs are typically higher than other parts of the world, partly due to high consenting costs and potentially due to large government subsidies distorting competitive and efficiency drivers to reduce costs).

Figure 17 Cost of solar panels



Source: Bloomberg Earth Policy Institute

Figure 18 Prices of residential solar power continue to fall



Source: Lawrence Berkley National Laboratory August 2016

The current installed costs of solar PV systems (per watt) in New Zealand are:

Residential scale

NZ$2.50–$3.00 for systems less than 1–2 kW

NZ$2.20–$2.50 for systems 3–5 kW

Commercial scale

NZ$1.60–$2.00 for systems up to 30 kW

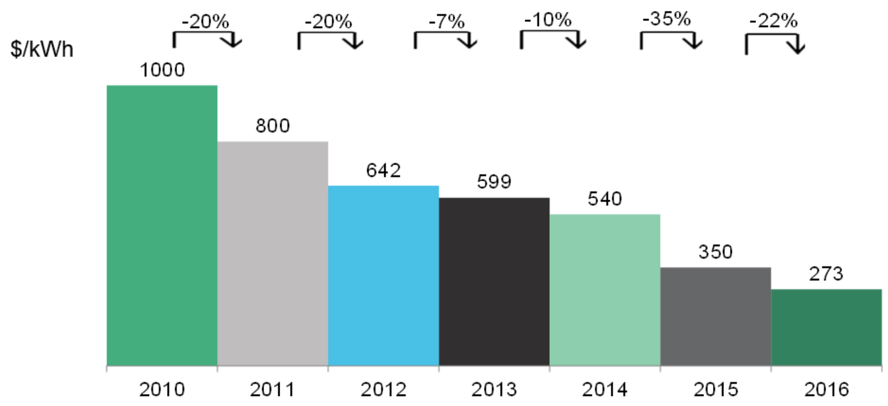
NZ$1.30–$1.60 for systems 100 kW and above

6.3.2. Costs of battery technology

While numerous technologies have been developed as replacements to the traditional lead-acid battery, lithium-ion is the current leader in terms of the combined requirements of cost, service life and energy density.

The widespread adoption of this technology by the vehicle industry is now seeing massive investment in production capability, which will continue to drive down costs through manufacturing efficiency. Over the past 5 years, battery prices have fallen at a year-on-year rate of 20%, resulting in 2016 prices being 30% of 2010 prices. While this trend is expected to slow, battery prices are still expected to fall again to 30% of today's prices in less than 10 years (historically most forecasts for both solar and battery technology have been too conservative).

Figure 19 Prices of batteries are dropping rapidly



Source: BNEF lithium-ion battery price survey, 2010–2016 ($/kWh) (BNEF 2017).

6.4. Distributed battery solution examples

There are many options for distributed battery systems. We discuss three examples below, each with different capacity and design features.

6.4.1. Tesla Powerwall 2

The Tesla Powerwall 2 provides 5 kW of continuous power and 13.2 kWh of energy storage. It is a stand-alone unit with its own inverter (installed separately to the solar PV array). It can provide full backup (provided load is less than 5 kW) in the event of a grid-power outage. Retail price is around US$10,000.

6.4.2. LG Chem

This is a compact battery-only unit with sizes ranging from 3.3 kWh to 10 kWh capacity. It is used with a separate hybrid inverter, which would be shared with the solar PV array. Retail price is around US$4,500 for the 3.3 kWh model and US$8,500 for the 10 kWh model.

6.4.3. Enphase

This is a small modular battery of 260 W/1.2 kWh capacity. Multiple units can be stacked together to provide the amount of storage required. The cost of each unit is around US$1,500.

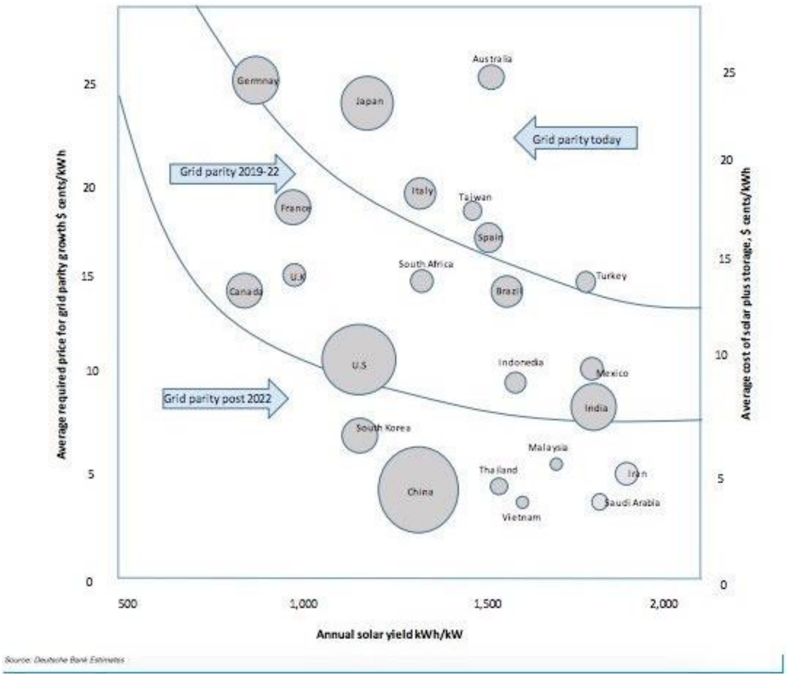
The system is optimised architecturally to work with the Enphase micro inverter (one small inverter per panel) system which can be used for the solar PV array instead of a single string inverter.

6.5. Grid parity

With the combined price falls in both solar PV and battery technology, this is now providing a solution for generating and managing energy at a cost equivalent to that of a grid-electricity service.

Based on an analysis by Deutsche Bank, the solar energy conditions (around 1,500 kWh per annum) and grid energy costs (US$0.20 plus), distributed solar/battery solutions have already reached grid parity in some parts of the world.

Figure 20 Grid parity has been achieved already



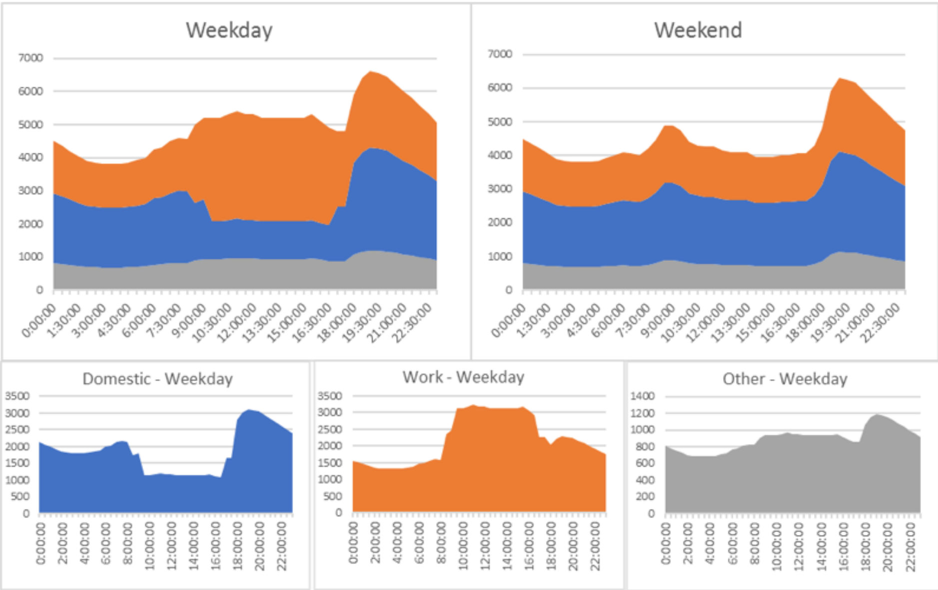
Source: Vishal Shah, at Deutsche Bank

Based on this analysis, it is suggested that solar and battery storage are able to achieve grid parity today in Polynesia.

6.6. Methodology

From the overall load profiles for each country, the residential and commercial load profiles are extracted using a demand-profile builder tool, developed for this study. This considers the differences between weekday and weekend profiles, sector energy-usage breakdown data, and creates a demand profile for domestic and commercial customers. As an example, Figure 21 shows Tonga's dry-season electricity demand profile.

Figure 21 Tonga: Dry-season electricity demand profile



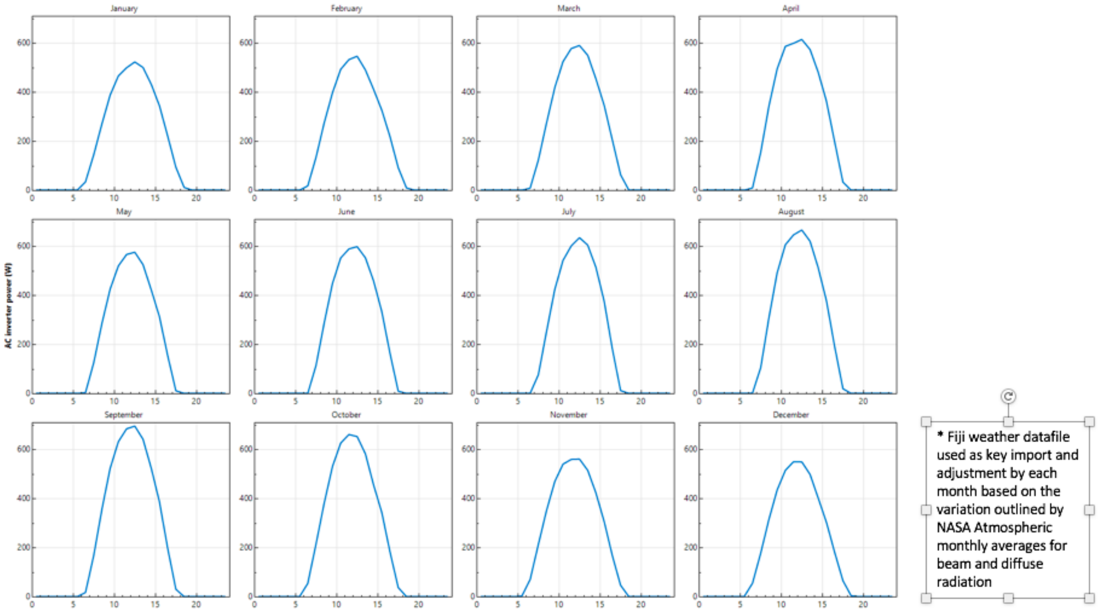
Source: Author (Gareth Williams)

Based on the number of connections, a representative load profile for a "typical" residential and commercial customer is established.

A model has been created using the NREL (National Renewable Energy Laboratory) SAM (system advisor model) simulation tool which allows both solar and batteries systems to be considered and the impact on both total energy use and the grid-electricity-demand profile to be derived. This allows the potential savings for consumer energy costs and on-grid electricity demand to be estimated. Financial viability is then considered.

The NREL SAM model provides a solar radiation model for Fiji. This data has been used as the base and adjusted using a ratio of the NASA monthly solar insolation data for each location.

Figure 22 Solar radiation model for Fiji



Source: Author (Gareth Williams)

6.7. Trends in balance of system costs

6.7.1. Overall BOS costs

BOS costs include all components of the PV system other than the panels: design; permitting, notably; wiring; switches; mounts; inverters, which convert DC into AC; batteries; software; and radiation sensors. Design, management and administration costs accounted for an average of 37% of total system costs (GTM Research 2011).

Utility-scale BOS costs would include grid injection, land, construction material and buildings. For residential PV systems, BOS costs can account for 55%–60% of the total PV-system costs or US$1.6–US$1.85/W. LCOE is therefore highly dependent on BOS costs (IRENA 2018; Mundada et al. 2016). Inverters typically account for 5% of installed systems costs or US$0.27/W–US$1.08/W.

IRENA (2012) projects PV-system costs for residential systems to decline from US$4,000/kW–US$6,000/kW in 2010 to US$1,800/kW–US$2,700/kW by 2020. Current costs Current costs in New Zealand are around NZ$2,500–NZ$3,000. As PV-module costs decline, BOS costs will become proportionately more important.

6.7.2. Profile and balancing costs

This section focuses on batteries and diesel backup.

<u>Storage</u>

DiOrio et al. (2015) provide analysis of lithium-ion and lead-acid battery systems.

Lithium-ion

Table 18 Specifications for a single Tesla Powerwall battery pack.

Item	Specification
Price	US$3,000 (includes installation, permitting)
Capacity	7 kWh
Power	2.0 kW continuous, 3.3 kW peak
Efficiency	92%
Voltage	350–450 V
Current	5.8 A nominal, 8.6 A peak
Charge limits	min 30%, max 100%, full capacity 10 kWh
Battery life	15 years

Source: DiOrio et al. 2015.

It is assumed that the battery begins with 7 kWh of daily life-cycle and is replaced once the maximum capacity has degraded to 70%. Batteries are fully cycled daily: 5,475 cycles over 15 years.

Lead acid

Table 19 Lead-acid batteries

Item	Specification
Price	US$425 (includes installation, permitting)
Capacity	1.68 kWh (4-hour discharge)
Power	420 W (4-hour discharge)
Efficiency	92% assumed
Voltage	12 V
Current	35 A (4-hour discharge), 30 A (charging)
Charge limits	Min 30%, max 100%
Battery life	

Source: DiOrio et al. 2015.

Replacement of lead-acid batteries occurs when degradation reaches 70% of maximum capacity: 1,400 cycles.

Diesel generators

Diesel power plants can operate with wide fuel and operational flexibility, high reliability and security and rapid start-up (Baurzhan and Jenkins 2017). Modular design makes them flexible for expansion. The efficiency of diesel engines is around 42% to 52%.

Table 20 Costs of diesel generation in Sub-Saharan Africa

Item	Specification
Installed capacity	130 MW
Capital cost	US$84m (US$0.65m/MW)
Operating life	25 years
Construction period	1 year
Energy efficiency	42%
Average availability after degradation	89% of installed capacity
Fuel requirement	0.21L per kWh
Annual capacity degradation	1%
Fixed O&M	US$15 per kW/year
Variable O&M	US$4 per MWh
Grid-level system cost	US$0.56 per MWh
Current price of heavy fuel oil (HFO)	US%171 tonne (oil at US$26.79 per barrel)
Calorific value of HFO	41.73 MJ/L

Source: Baurzhan and Jenkins 2017.

Table 21 Costs of diesel generation in Kenya

Item	Specification
Installed capacity	455.8 MW (2012) & 796.8 MW (2017)
Outage rate	0.098
Auxiliary load factor	0.94
Ramp rate	0.12 GW/h
Variable fuel consumption	7.66 MJ/kW h
Fixed fuel consumption	0.008 MJ/h
Start-up fuel consumption	0.084 J
Diesel fuel cost	US$14.6/GJ
Variable O&M	US$9.0/MWh
Annual fixed O&M	US$/kW

Source: Rose et al. 2016.

6.8. Stranded assets

It is common for energy investments to be asset specific because they are designed for a specific purpose – such as a transmission grid or coal-loading facility – and they have little, if any, value in their next best alternative use. Changes in market conditions, the regulatory environment, and technology, can reduce the return on investment and consequently asset value and result in unanticipated write-downs and conversion to liabilities (Caldecott et al. 2013).

Many Pacific Island nations have invested in transmission infrastructure dedicated to distributing electricity from a centralised generation facility, in many cases diesel generation.

Transitioning to solar, particularly off-grid/microgrid household scale lowers the utilisation of an asset-specific investment. Investment in the grid has occurred, often financed by loans, and the asset is no longer able to earn an economic return. The transition could be partial, possibly with diesel running as a backup when intermittent solar is unable to meet demand. Total transition is possible, in principle, with solar plus battery storage.

Recovery of stranded assets is a key issue in the transition to solar-based generation. For example, residential solar might offer cost savings to households; but government or its functional equivalent would have to recover stranded costs. Ex post, the asset might have zero economic value. However, the asset owner, for example government, could have financial obligations to meet and be locked in to repayment obligations over an extended period. The impact of losing asset value on the economy's potential investment pool should also be considered.

Table 22 Stranded asset costs

Asset	Economic valuation parameters
Diesel generators	Capacity Remaining economic life Salvage value
Transmission	Remaining economic life of asset Salvage value Annual OPEX Expected costs of upgrade Weighted cost of capital
Distribution	Salvage value Partial retirement Upgrade costs

Source: Adapted from Caldecott et al. 2013.

7. Results

In this section, we outline the results of our research.

7.1. Scenarios and assumptions

Modelling software used is the SAM developed by the National Energy Research Laboratory (NREL). Weather data input files have been developed using a proxy from the Fiji weather data file with monthly adjustments to beam and diffuse irradiance values from monthly averages in the NASA's atmospheric database. Load-data profiles have been derived using dry and wet season total-load profiles and disaggregated using a proportion of energy use by market sector as well as assumptions for increased weekday, daytime-energy-use consumption from the working sector.

Domestic batteries have been modelled under the sizing assumptions of the Enphase 1.2 kWh modular-battery product. Commercial batteries have been modelled under the sizing assumptions of the Tesla Powerwall 2, 14 kWh battery capacity product.

Representative system sizes have been selected with the objective of providing the bulk majority of each user's individual energy use rather than optimising economics. Some systems are slightly oversized (where total generation is slightly greater than total electricity consumption); however, this results in the battery being optimised to limit the electricity consumed from the grid.

Domestic pricing assumptions (prices in USD) of $1.70/W and $1,020/kWh have been used to represent increased marginal cost per watt of smaller PV-system installations and reflective of Enphase's more expensive battery solution. Commercial pricing assumptions of $1.22/W and $734/W have been used to represent the economies of scale of larger systems for commercial as well as the more price-competitive Tesla Powerwall 2 battery solution.

7.2. Spreadsheet model and results

The following three scenarios are analysed for each island: domestic feasibility for distributed solar and battery, commercial feasibility for distributed solar and battery, and commercial feasibility for distributed solar without storage.

7.2.1. Samoa

Samoa: <u>Domestic</u> economic feasibility summary for distributed solar and battery

Distributed system specifications
PV capacity: **1.77 kW$_p$**
Battery capacity: **4.80 kWh**
Battery power: **1.08 kW**
Battery to PV capacity ratio: **2.71**

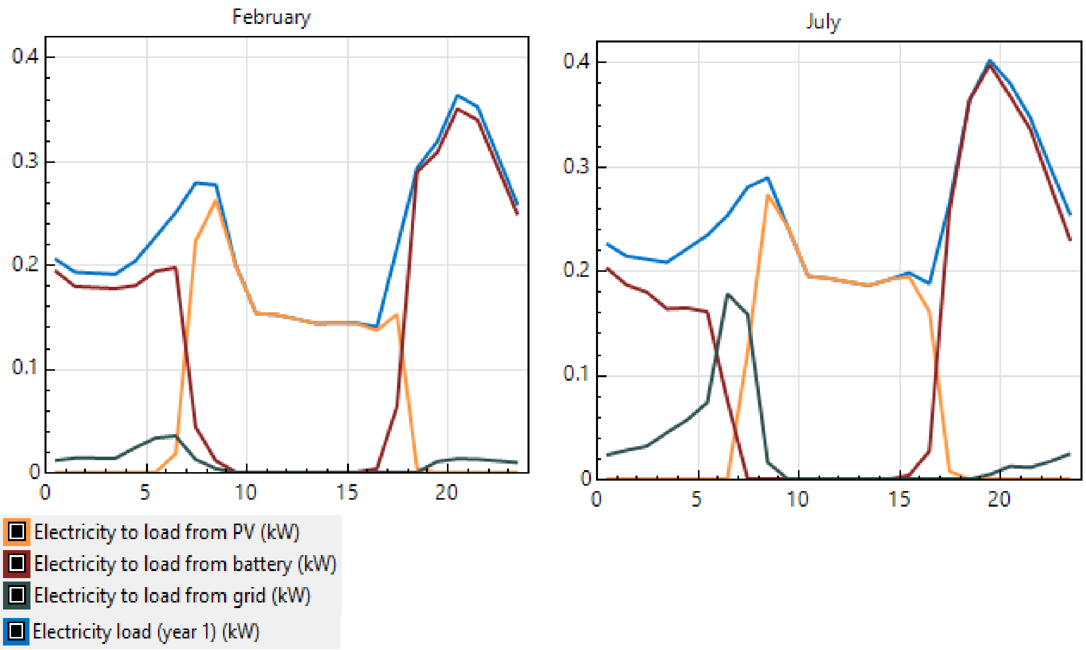
Financial comparison metrics
Average grid-electricity price: **37 ¢/kWh**
$/W installed price PV: **1.71 $/W**
$/kWh installed battery: **1,020 $/kWh**
Load: **2,090 kWh**
Generation: **2,709 kWh**
Import: **131 kWh**
Export: **753 kWh**

Table 23 Key system and economic metrics

Metric	Value
Annual energy (year 1)	2,709 kWh
Capacity factor (year 1)	17.5%
Energy yield (year 1)	1,529 kWh/kW
Performance ratio (year 1)	0.74
Battery efficiency (incl. converter + ancillary)	92.11%
Levelized COE (nominal)	32.51 ¢/kWh
Levelized COE (real)	25.16 ¢/kWh
Electricity bill without system (year 1)	$773
Electricity bill with system (year 1)	$50
Net savings with system (year 1)	$724
Net present value	$438
Payback period	12.9 years
Discounted payback period	21.1 years
Net capital cost	$9,355
Equity	$9,355
Debt	$0

Source: The authors

Figure 23 System generation to grid balance



Wet season: February
Dry season: July

Source: The authors

<u>Comments</u>

LCOE of the solar and battery solution in real terms is 25.2 ¢/kWh, which is very competitive with the grid-unit price of 37 ¢/kWh. The net present value (NPV) of the system is $438, meaning that the project exhibits better than neutral economic benefit but is not largely economically favourable compared to the grid. Expected payback on initial capital cost of $9,335 is about 13 years based on this scenario.

Slightly oversizing the system means that exported energy is 750 kWh per year and the system would still require 130 kWh of imported grid electricity. This is due to the combination of the timing of energy loads, PV and battery capacity assumed from the system.

Domestic solar and battery structure exhibits a higher battery to PV capacity ratio as the expected daytime energy load is lower. This ultimately increases the LCOE as a greater amount of storage would be required for a small peak solar capacity.

Samoa: Commercial economic feasibility summary for distributed solar and battery

Distributed system specifications
PV capacity: **26.9 kW_p**
Battery capacity: **56 kWh**
Battery power: **20 kW**

Battery to PV capacity ratio: **2.08**
Load: **37,028 kWh**
Generation: **42,234 kWh**
Import: **3,217 kWh**
Export: **8,422 kWh**

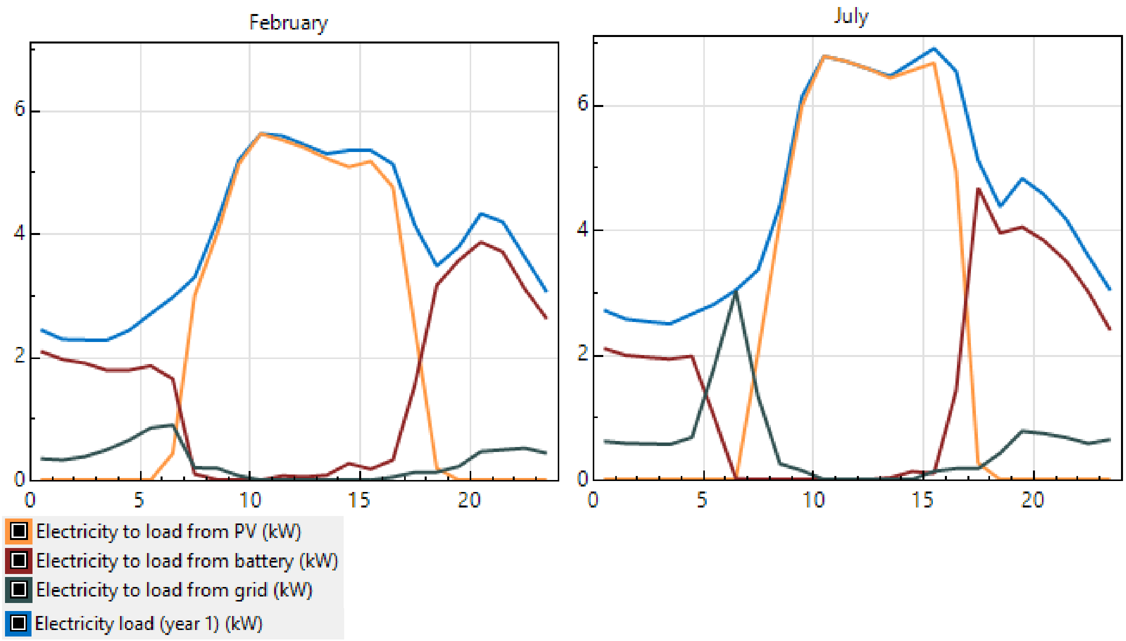
Financial comparison metrics
Average grid-electricity price: **39 ¢/kWh**
$/W installed price PV: **1.22 $/W**
$/kWh installed battery: **734 $/kWh**

Table 24 Key system and economic metrics

Metric	Value
Annual energy (year 1)	42,234 kWh
Capacity factor (year 1)	17.9%
Energy yield (year 1)	1,572 kWh/kW
Performance ratio (year 1)	0.76
Battery efficiency (incl. converter + ancillary)	91.35%
Levelized COE (nominal)	19.67 ¢/kWh
Levelized COE (real)	15.22 ¢/kWh
Electricity bill without system (year 1)	$14,441
Electricity bill with system (year 1)	$1,255
Net savings with system (year 1)	$13,187
Net present value	$102,657
Payback period	6.6 years
Discounted payback period	7.9 years
Net capital cost	$85,208
Equity	$85,208
Debt	$0

Source: The authors.

Figure 24 System generation to grid balance



Wet season: February
Dry season: July

Source: The authors

Comments

LCOE of the solar and battery solution in real terms is 15 ¢/kWh, which is extremely competitive against grid price of 39 ¢/kWh. The NPV of the system is $102,660, which is a combined result of high electricity prices for commercial users, lower $/W from economies of scale and increased daytime loads requiring a lower battery to PV capacity ratio to capture the value from solar output. Expected payback on the initial capital cost of $85,208 is about 6.6 years based on this scenario.

Slightly oversizing the system means that exported energy is 8,422 kWh per year and the commercial users would still require 3,217 kWh of imported grid electricity. This is due to the combination of the timing of energy loads and PV and battery capacity assumed from the system.

Commercial solar and battery systems exhibit a lower battery to PV capacity ratio as the expected daytime energy load is higher between 9am and 5pm on weekdays when the greatest PV output is observed.

Samoa: Commercial economic feasibility summary for distributed solar without storage

Distributed system specifications
PV capacity: **16.5 kW_p**

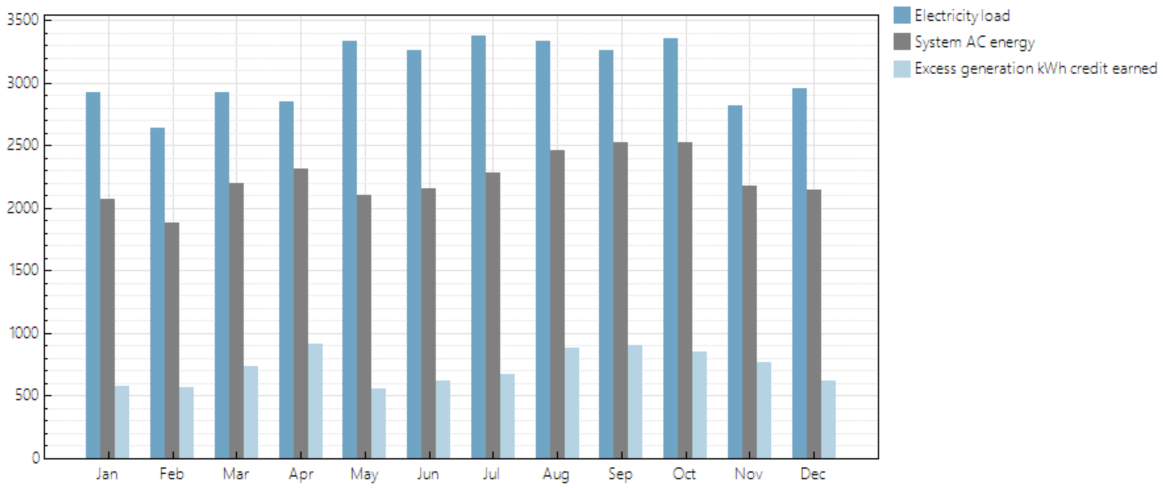
Financial comparison metrics:
Average grid-electricity price: 39 ¢/kWh
$/W installed price PV: 1.22 $/W

Table 25 Key system and economic metrics

Metric	Value
Annual energy (year 1)	26,849 kWh
Capacity factor (year 1)	18.5%
Energy yield (year 1)	1,624 kWh/kW
Performance ratio (year 1)	0.78
Levelized COE (nominal)	9.33 ¢/kWh
Levelized COE (real)	7.22 ¢/kWh
Electricity bill without system (year 1)	$14,441
Electricity bill with system (year 1)	$7,358
Net savings with system (year 1)	$7,083
Net present value	$81,885
Payback period	3.4 years
Discounted payback period	3.7 years
Net capital cost	$23,194
Equity	$23,194
Debt	$0

Source: The authors

Figure 25 System generation to grid balance



Load: **37,028 kWh**
Generation: **26,848 kWh**
Import: **18,867 kWh**
Export: **8,687 kWh**

Source: The authors

Comments

Without a battery installed with the solar PV system, the paybacks and LCOE values are much more economically competitive as the added cost from the batteries to address evening loads increases both. However, with solar on its own, a smaller proportion of the electricity load can be addressed from solar which means the project NPVs are smaller than with a battery attached showing that adding additional panels with a battery still has a positive business case.

Oversizing the system slightly means that export output is greater, this is partly due to the load assumptions for weekends not increasing through the day as they do for weekdays.

LCOE of the solar on its own is very competitive at a real price of 7.2 ¢/kWh from current $/W installed assumptions. NPV of the system would be approximately $81,885 with a simple, undiscounted, payback period of only 3.4 years.

7.2.2. Tonga

Tonga: Domestic economic feasibility summary for distributed solar and battery

Distributed system specifications
PV capacity: **1.48 kW_p**
Battery capacity: **4.8 kWh**
Battery power: **1.08 kW**
Battery to PV capacity ratio: **3.24**

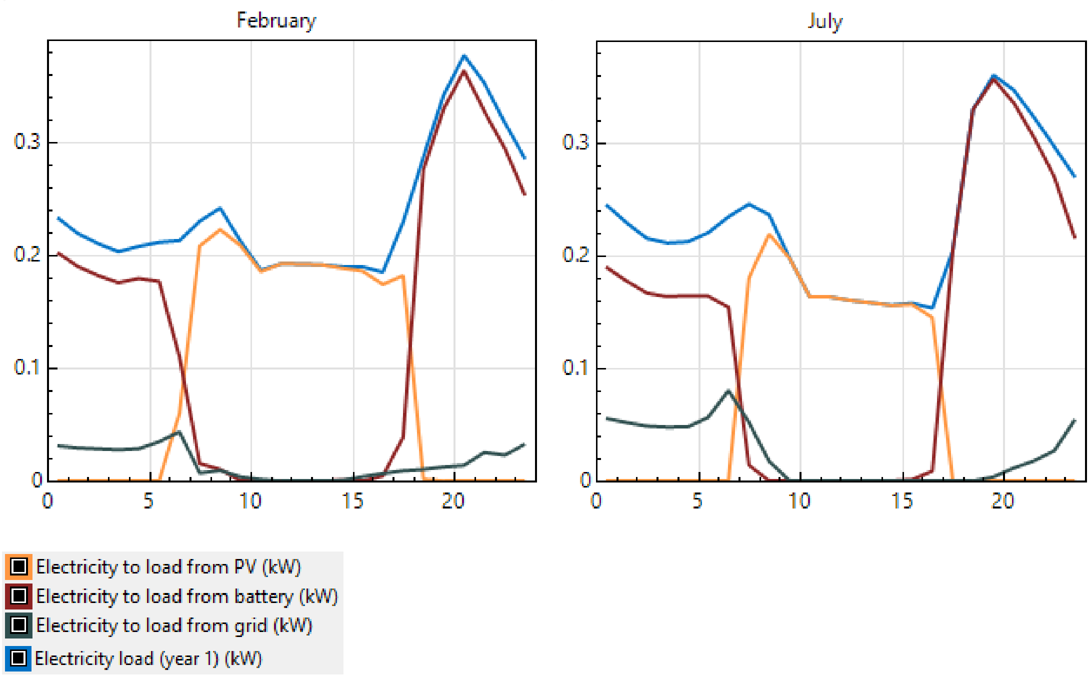
Financial comparison metrics
Average grid-electricity price: **32 ¢/kWh**
$/W installed price PV: **1.71 $/W**
$/kWh installed battery: **1,020 $/kWh**

Table 26 Key system and economic metrics

Metric	Value
Annual energy (year 1)	2,755 kWh
Capacity factor (year 1)	21.3%
Energy yield (year 1)	1,867 kWh/kW
Performance ratio (year 1)	0.74
Battery efficiency (incl. converter + ancillary)	92.13%
Levelized COE (nominal)	29.71 ¢/kWh
Levelized COE (real)	22.99 ¢/kWh
Electricity bill without system (year 1)	$653
Electricity bill with system (year 1)	$47
Net savings with system (year 1)	$607
Net present value	$-592
Payback period	14.3 years
Discounted payback period	NaN
Net capital cost	$8,746
Equity	$8,746
Debt	$0

Source: The authors

Figure 26 System generation to grid balance



Wet season: February
Dry season: July

Load:	**2,042 kWh**
Generation:	**2,755 kWh**
Import:	**142 kWh**
Export:	**859 kWh**

Source: The authors

Comments

LCOE of the solar and battery solution in real terms is 23 ¢/kWh which is competitive against grid-unit price of 32 ¢/kWh. The NPV of the system is -$592, meaning that the project exhibits negative present value over the lifetime of the project which his not significant. NPV can be positive by decreasing the system size which increases the requirement of electricity from the grid. Expected payback on initial capital cost of $8,746 is about 14 years based on this modelled scenario.

Slightly oversizing the system means that exported energy is 860 kWh per year and the system would still require 140 kWh of imported grid electricity. This is due to the combination of the timing of energy loads, PV and battery capacity assumed from the system.

Domestic solar and battery structure exhibits a higher battery to PV capacity ratio as the expected daytime energy load is lower. Increased energy yield expected in Tonga also pushes up the battery to PV capacity ratio as one less panel is needed for a similar output.

Tonga: <u>Commercial</u> economic feasibility summary for distributed solar and battery

Distributed system specifications

PV capacity:	**1.48 kW_p**
Battery capacity:	**4.8 kWh**
Battery power:	**1.08 kW**

Battery to PV capacity ratio: 3.24

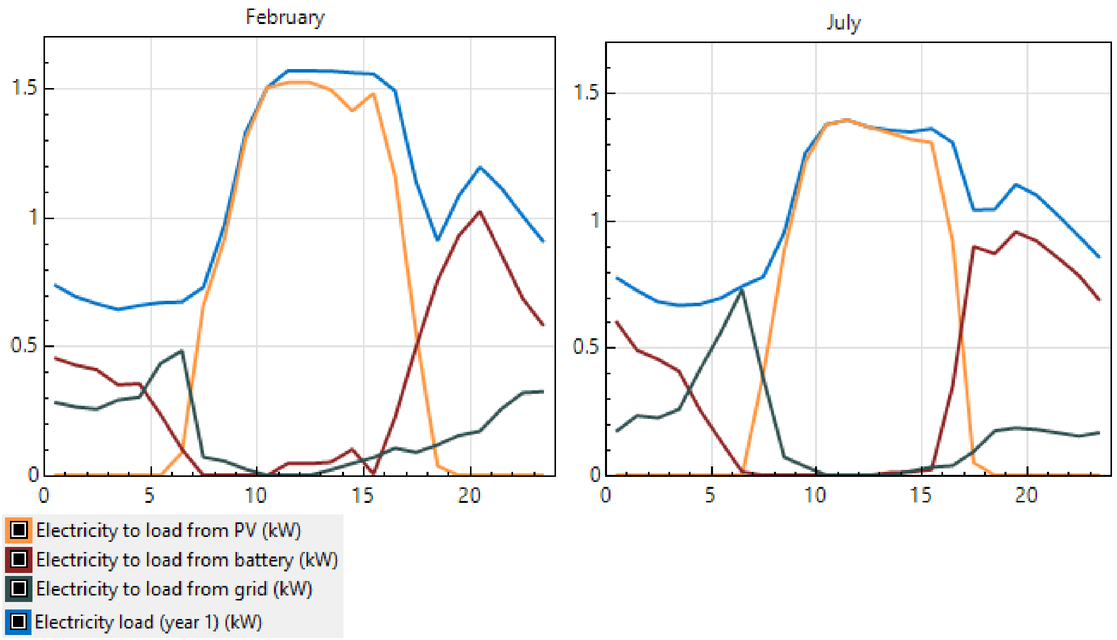
Financial comparison metrics
Average grid-electricity price: 32 ¢/kWh
$/W installed price PV: 1.71 $/W
$/kWh installed battery: 1020 $/kWh

Table 27 Key system and economic metrics

Metric	Value
Annual energy (year 1)	9,330 kWh
Capacity factor (year 1)	17.2%
Energy yield (year 1)	1,505 kWh/kW
Performance ratio (year 1)	0.76
Battery efficiency (incl. converter + ancillary)	91.26%
Levelized COE (nominal)	20.96 ¢/kWh
Levelized COE (real)	16.22 ¢/kWh
Electricity bill without system (year 1)	$2,939
Electricity bill with system (year 1)	$429
Net savings with system (year 1)	$2,510
Net present value	$14,907
Payback period	8.2 years
Discounted payback period	10.5 years
Net capital cost	$20,102
Equity	$20,102
Debt	$0

Source: The authors

Figure 27 System generation to grid balance



Wet season: February
Dry season: July

Source: The authors

Comment

LCOE of the solar and battery solution in real terms is 16 ¢/kW, competitive against grid prices of 32 ¢/kWh for commercial users. The NPV of the system is $14,907. This is much lower than other commercial customers in the Cook Islands and Samoa, as the expected annual electricity use of an average Tongan commercial customer is much lower at 9,200 kWh per year. Expected payback on initial capital cost of $20,102 is about 8.2 years based on in this scenario.

Slightly oversizing the system means that exported energy is 1,487 kWh per year and the users would still require 1,338 kWh of imported grid electricity. This is due to the combination of the timing of energy loads, PV and battery capacity assumed from the system. Commercial solar and battery systems exhibit a lower battery to PV capacity ratio as the expected daytime energy load is higher during between 9am and 5pm on weekdays.

Tonga: Commercial economic feasibility summary for distributed solar without storage

Distributed system specifications
PV capacity: 4.13 kW_p

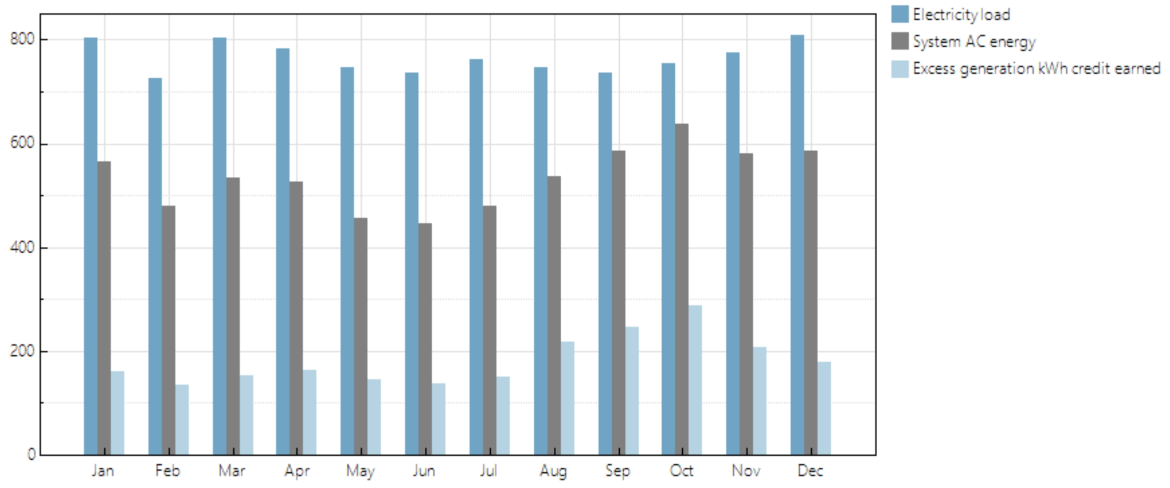
Financial comparison metrics
Average grid-electricity price: 32 ¢/kWh
$/W installed price PV: 1.22 $/W

Table 28 Key system and economic metrics

Metric	Value
Annual energy (year 1)	6,413 kWh
Capacity factor (year 1)	17.7%
Energy yield (year 1)	1,552 kWh/kW
Performance ratio (year 1)	0.78
Levelized COE (nominal)	9.77 ¢/kWh
Levelized COE (real)	7.56 ¢/kWh
Electricity bill without system (year 1)	$2,939
Electricity bill with system (year 1)	$1,583
Net savings with system (year 1)	$1,356
Net present value	$13,850
Payback period	4.5 years
Discounted payback period	5.0 years
Net capital cost	$5,798
Equity	$5,798
Debt	$0

Source: The authors

Figure 28 System generation to grid balance



Load: **9,183 kWh**
Generation: **6,413 kWh**
Import: **4,946 kWh**
Export: **2,176 kWh**

Source: The authors

<u>Comment</u>

Without a battery installed with the solar PV system, the paybacks and LCOE values are much more economically competitive as the added cost from the batteries to address evening loads increases both. However, with solar on its own, a smaller proportion of the electricity load can be addressed from solar, which means the project NPVs are smaller than with a battery attached, showing that adding additional panels with a battery is still a positive business case for a marginal addition basis.

Oversizing the system slightly means that export output is greater, this is partly due to the load assumptions for weekends not increasing through the day as they do for weekdays.

LCOE of the solar on its own is very competitive at a real price of 7.6 ¢/kWh from current $/W installed assumptions. The NPV of the system would be approximately $13,850 with a simple, undiscounted, payback period of only 4.5 years.

7.2.3. Cook Islands

Cook Islands: <u>Domestic</u> economic feasibility summary for distributed solar and battery

Distributed system specifications
PV capacity: **3.54 kW_p**
Battery capacity: **9.6 kWh**
Battery power: **2.16 kW**
Battery to PV capacity ratio: **2.71**

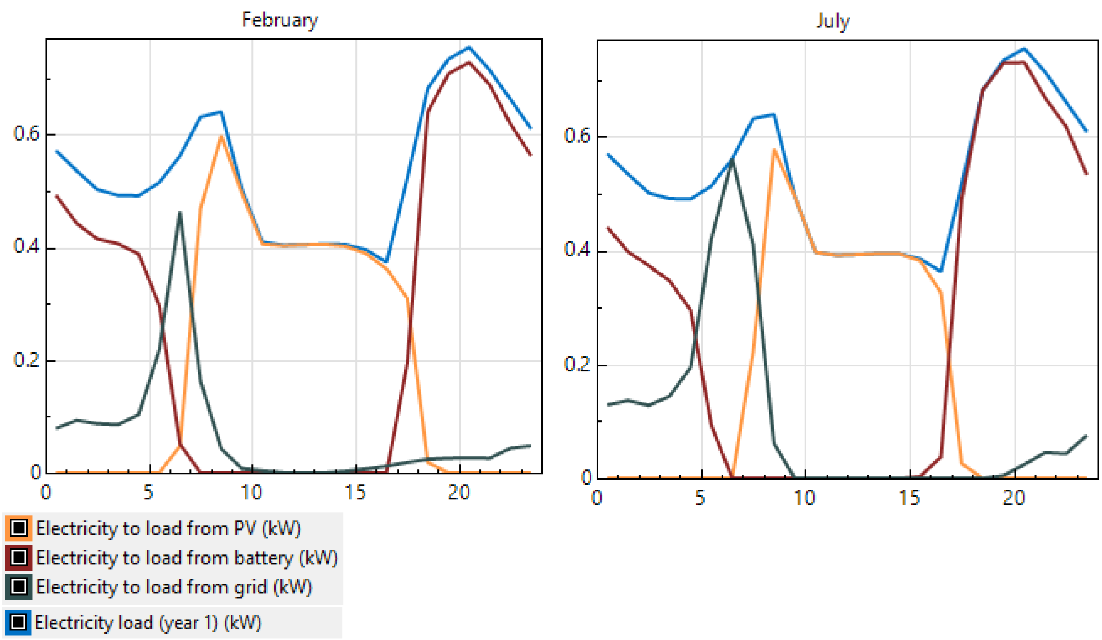
Financial comparison metrics
Average grid-electricity price: **61 ¢/kWh**
$/W installed price PV: **1.71 $/W**
$/kWh installed battery: **1020 $/kWh**

Table 29 Key system and economic metrics

Metric	Value
Annual energy (year 1)	5,159 kWh
Capacity factor (year 1)	16.6%
Energy yield (year 1)	1,456 kWh/kW
Performance ratio (year 1)	0.74
Battery efficiency (incl. converter + ancillary)	92.09%
Levelized COE (nominal)	33.90 ¢/kWh
Levelized COE (real)	26.23 ¢/kWh
Electricity bill without system (year 1)	$2,888
Electricity bill with system (year 1)	$392
Net savings with system (year 1)	$2,496
Net present value	$17,139
Payback period	7.5 years
Discounted payback period	9.3 years
Net capital cost	$18,568
Equity	$18,568
Debt	$0

Source: The authors

Figure 29 System generation to grid balance



Wet season: February
Dry season: July

Load:	**4,719 kWh**
Generation:	**5,159 kWh**
Import:	**640 kWh**
Export:	**1,079 kWh**

Source: The authors

Comments

LCOE of the solar and battery solution in real terms is 26 ¢/kWh which is extremely competitive against grid price of 61 ¢/kWh. The NPV of the system is $17,140, which is a combined result of very high grid-electricity prices in the Cook Islands and greater average annual electricity consumption meaning a larger kWh volume can be offset from the solar and battery system. Expected payback on initial capital cost of $18,568 is about 7.5 years based on simple payback approach.

Slightly oversizing the system means that exported energy is 1,079 kWh per year and the system would still require 640 kWh of imported grid electricity. This is due to the combination of the timing of energy loads, PV and battery capacity assumed from the system.

Domestic solar and battery structure exhibits a higher battery to PV capacity ratio as the expected daytime energy load is lower but even with a larger battery system required to capture solar-output value, the economics are extremely favourable in the Cook Islands.

Cook Islands: Commercial economic feasibility summary for distributed solar and battery

Distributed system specifications

PV capacity: **16.53 kW_p**
Battery capacity: **42 kWh**
Battery power: **15 kW**
Battery to PV capacity ratio: **2.54**

Financial comparison metrics

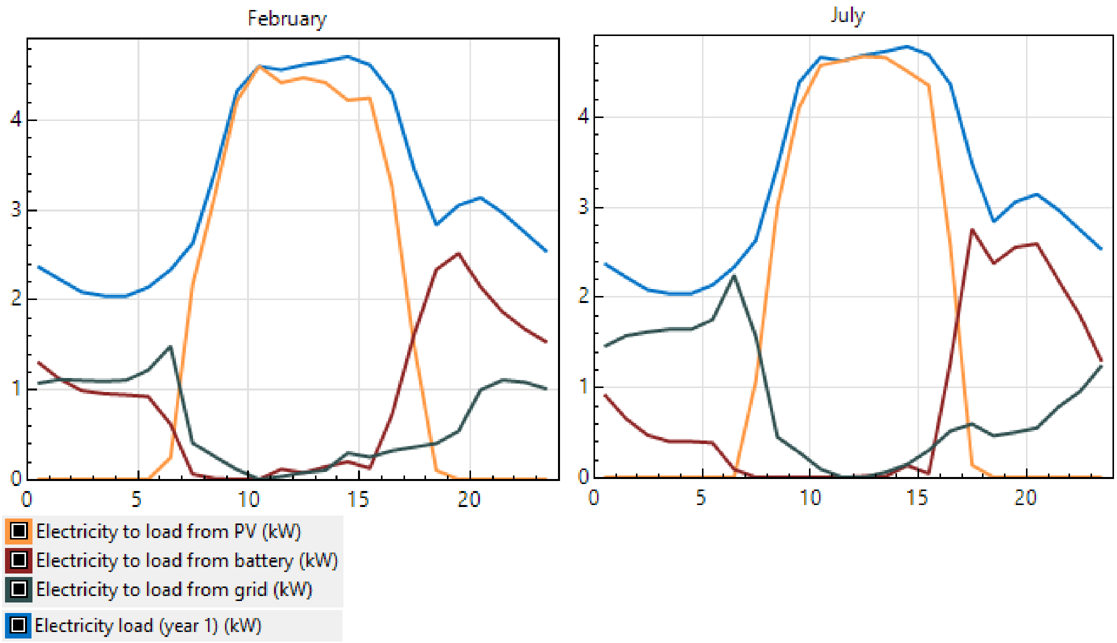
Average grid-electricity price: **64 ¢/kWh**
$/W installed price PV: **1.22 $/W**
$/kWh installed battery: **734 $/kWh**

Table 30 Key system and economic metrics

Metric	Value
Annual energy (year 1)	24,763 kWh
Capacity factor (year 1)	17.1%
Energy yield (year 1)	1,498 kWh/kW
Performance ratio (year 1)	0.76
Battery efficiency (incl. converter + ancillary)	91.29%
Levelized COE (nominal)	22.77 ¢/kWh
Levelized COE (real)	17.62 ¢/kWh
Electricity bill without system (year 1)	$18,281
Electricity bill with system (year 1)	$3,542
Net savings with system (year 1)	$14,738
Net present value	$157,699
Payback period	4.0 years
Discounted payback period	4.4 years
Net capital cost	$58,357
Equity	$58,357
Debt	$0

Source: The authors

Figure 30 System generation to grid balance



Wet season: February
Dry season: July

Load: **28,564 kWh**
Generation: **24,762 kWh**
Import: **5,534 kWh**
Export: **1,734 kWh**

Source: The authors

Comments

LCOE of solar and battery solution in real terms is 17.6 ¢/kW, is very competitive against grid prices of 64 ¢/kWh for commercial users. The NPV of the system is $157,700 which is greater than Samoa’s even though the expected output of the system is only 60% of the expected output from Samoa’s commercial reference system. Expected payback on the initial capital cost of $58,360 is about 4 years based on simple payback approach due to the high grid-electricity prices in the Cook Islands.

This reference system would result in an exported electricity volume of 1,734 kWh with 5,534 kWh of grid electricity still expected to be required from the grid. Commercial solar and battery systems exhibit a lower battery to PV capacity ratio as the expected daytime energy load is higher during between 9am and 5pm on weekdays.

Cook Islands: Commercial economic feasibility summary for distributed solar without storage

Distributed system specifications
PV capacity: **13.3 kW$_p$**

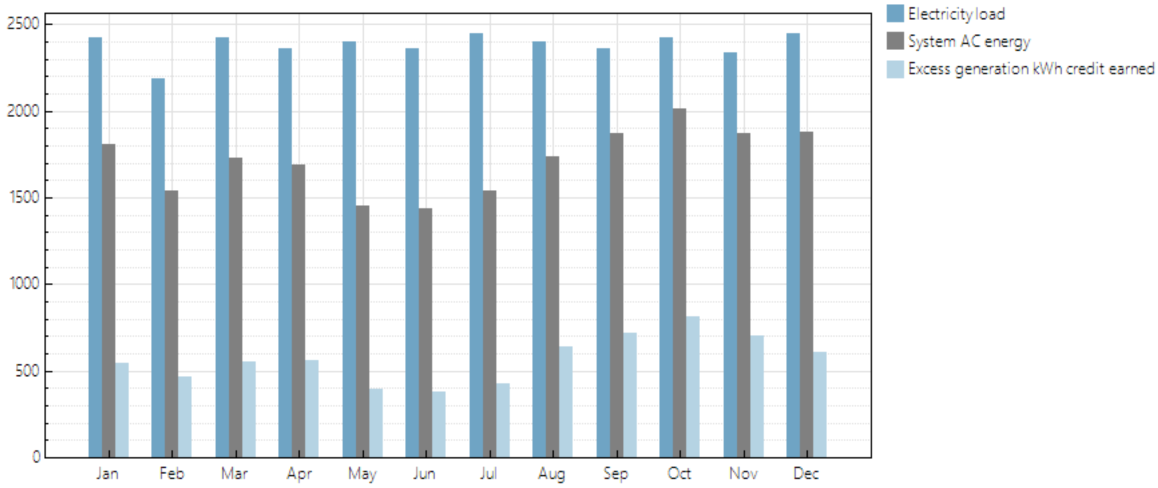
Financial comparison metrics
Average grid-electricity price: 64 ¢/kWh
$/W installed price PV: **1.22 $/W**

Table 31 Key system and economic metrics

Metric	Value
Annual energy (year 1)	20,587 kWh
Capacity factor (year 1)	17.7%
Energy yield (year 1)	1,550 kWh/kW
Performance ratio (year 1)	0.78
Levelized COE (nominal)	9.78 ¢/kWh
Levelized COE (real)	7.57 ¢/kWh
Electricity bill without system (year 1)	$18,281
Electricity bill with system (year 1)	$9,454
Net savings with system (year 1)	$8,827
Net present value	$115,403
Payback period	2.2 years
Discounted payback period	2.3 years
Net capital cost	$18,638
Equity	$18,638
Debt	$0

Source: The authors

Figure 31 System generation to grid balance



Load:	**28,564 kWh**
Generation:	**20,587 kWh**
Import:	**14,772 kWh**
Export:	**6,795 kWh**

Source: The authors

Comments

Without a battery installed with the solar PV system, the paybacks and LCOE values are much more economically competitive as the added cost from the batteries to address evening loads increases both. However, with solar on its own, a smaller proportion of the electricity load can be addressed from solar which means the project NPVs are smaller than with a battery attached, showing that adding additional panels with a battery still has a positive business case.

Oversizing the system slightly means that export output is greater. This is partly due to the load assumptions for weekends not increasing through the day as they do for weekdays. LCOE of the solar on its own is very competitive at a real price of 7.6 ¢/kWh from current $/W installed assumptions.

The NPV of the system would be approximately $115,000 with a simple, undiscounted payback period of only 2.2 years.

7.3. Summary of results and comments

Both domestic and commercial distributed solar and battery systems appear to compare favourably with current standard grid-electricity pricing, although the degree does vary by region.

Commercial distributed solar and battery systems have the most favourable financial viability due to the following reasons:

- High daytime electricity loads meaning that solar PV output can address load directly before the requirement for battery, this results in a lower battery to PV capacity ratio and drives down the resulting LCOE of these systems.
- Commercial electricity prices do not appear to exhibit price reductions with economies of scale (as would be observed in New Zealand).
- Larger PV and battery systems have assumed economies of scale resulting in lower $/W for PV and lower $/kWh of battery capacity for commercial customers, accelerating financial viability.
- Domestic users in each country have low electricity consumption (2,000 kWh–4,700 kWh annual consumption) compared to average users in New Zealand, which is around 7,200 kWh per year. Small use combined with lower daytime loads make domestic systems of lower financial standing but still appear have a viable business case. The requirement for batteries is more apparent for domestic customers with lower daytime loads.
- A single reference system has been selected for each user type aiming to address the majority of each customer's electricity consumption requirements. There may be other scenarios that have better financial outcomes. This could be investigated further should more research be required.

8. Conclusion

Falling costs of solar technology and batteries provide opportunities for Polynesian islands to invest in renewable sources to generate electricity and reduce dependency on imported fossil fuels. Transitioning from high-cost, centralised diesel-generated and distributed electricity to solar-based technology, with or without batteries, raises challenges.

Difficult environmental conditions require investment in components that will survive under a range of extreme weather conditions. More remote sites will require relatively more durable equipment. In order to achieve the full potential of solar with/without batteries it will be necessary to develop up-skilling programmes that reduce dependence on importing skilled technicians from overseas to attend to outages when they arise.

Dependence on donor funding raises at least two issues. First, donor funding for energy projects can result in long lead times and adds complexity to implementation and maintenance. Second, repayment obligations related to existing generation and distribution networks could act as a barrier to progress. Stranded assets is a major consideration. Incorporating the cost of existing obligations into the economic analysis is a topic for further research. A more complete assessment of existing financial obligations is necessary, along with other institutional barriers.

With the exception of "domestic solar + battery" for Tonga, Table 32 shows variable, but positive NPVs. These positive results will get better as technology improves and the costs of solar and batteries continue to decline. Bearing in mind the above caveats relating to existing infrastructure, these results signal economic potential. If investment were to occur and these economic returns realised, island communities would benefit from sustainable renewable sources of electricity, insulating their economies from uncertainties related to movements in international oil prices and unreliable shipping.

Table 32 Summary of financial returns

	Samoa	Tonga	Cook Islands
Domestic solar + battery	NPV $438 Payback 21.1 years	NPV -$592 NA	NPV $17,139 Payback 9.3 years
Commercial solar + battery	NPV $102,660 Payback 7.9 years	NPV $14,907 Payback 10.5 years	NPV $157,699 Payback 4.4 years
Commercial solar without battery	NPV $81,885 Payback 3.7 years	NPV $13,850 Payback 5 years	NPV $115,403 Payba ck 2.3 years

Source: The authors

Appendix A Hawaii solar initiatives

In 2015, Hawaii relied on oil for 69% and on coal for 13% of its electricity generation (Hawaii State Energy Office 2017). Energy prices are the highest among 50 states of the US. Average residential electricity prices have fallen from US$0.35/kWh in 2011 to US$0.28/kWh in 2016. Residential prices are highest on the islands of Kauai, US$0.34/kWh, and Lanai, US$0.34/kWh.

In recent years, solar has become the primary source of renewable energy. Most solar generation is by distributed PV systems supported by a variety of incentives and energy programmes described below.

Electricity is provided by two utilities. Hawaiian Electric Industries (HEI) is the largest supplier with subsidiaries Hawaiian Electric Company (HECO) serving Oahu; Maui Electric Company (MECO) serving Maui, Molokai, and Lanai; and, Hawaiian Electric Light (HELCO) serving the island of Hawaii. HEI is an investor-owned utility. Kauai Island Utility Cooperative (KIUC) is a cooperative serving the island of Kauai. Both utilities are regulated by the Public Utilities Commission (PUC).

If new generation is called for, HECO, MECO and HELCO are required to follow a competitive bidding framework. In March 2015, for distributed energy resource programmes, the PUC established procedures for interconnection that allow for grid-supportive services, transitioning the current net-energy metering (NEM) system, and creating new market choices for non-exporting and smart exporting systems.

Under the NEM programme:

- Customers received a credit at retail rate for electricity exported to the grid.
- If a customer used more electricity than was exported, the customer was charged for that net amount.
- If a customer exported more electricity than was used, the customer was charged a minimum bill and was allowed to carry excess credits forward to the next month.
- At the end of the 12-month billing cycle any excess credit was forfeited or used to reimburse any energy charges previously paid.

In October 2015, the PUC closed the NEM programme, grandfathered existing NEM customers and approved two programmes: customer grid supply (CGS) and customer self-supply (CSS). In 2016, the PUC established procedures to address grid capacity for distributed energy resources (DER) and renewable resources, integrating DER in a cost-effective manner, revising interconnection standards, tariffs, expanding DER options and customer participation.

The CGS programme is a modified version of NEM:

- Customers receive a PUC approved credit for energy exported to the grid.
- Customers are charged the retail rate for energy received from the grid and use credit received from exported electricity to offset charges.
- If a customer's credit exceeds their energy charge, then they pay a minimum bill.
- Any excess credit at the end of each billing month is forfeited.

Table 33 Credit for exporting to the grid

Island	Credit (US¢/kWh)
Oahu	15.07
Maui	17.16
Molokai	24.07
Lanai	27.88
Hawaii Island	15.14

Source: Hawaii State Energy Office, 2017

PUC established caps for each of the HEI companies: 25 MW for HECO, 5 MW for MECO and 5 MW for HELCO. The caps were established so as not to allow unconstrained growth of grid supply at the expense of forgoing opportunities to develop lower-cost sources or preventing HECO companies from offering community-based renewable sources.

CSS is available to permanent customers who own or lease a solar-generating facility and have a capacity of less than 100 kW. The system may include storage and is not designed to export electricity to the grid:

- Customers are not compensated for electricity exported.
- Customers pay for electricity used from the grid.
- Residential customers are charged a minimum monthly bill of US$25.

Table 34 Hawaiian Electric Company feed-in tariffs

Tier	Island	PV		CSP		On-shore wind		In-line hydro	
		¢/kWh	Limit	¢/kWh	Limit	¢/kWh	Limit	¢/kWh	Limit
1	All	21.8* 27.4**	20 kW	26.9* 33.1*	20 kW	16.1	20 kW	21.3	20 kW
2	Oahu	18.9* 23.8**	500 kW	25.4* 27.5**	500 kW	13.8	100 kW	18.9	100 kW
	Maui & Hawaii		250 kW		25 0kW				
	Lanai & Molokai		10 0kW		100 kW				
3	Oahu	19.7* 23.6**	5 MW	31.5* 33.5**	5 MW	12.0	5 MW		
	Maui & Hawaii		2.72 MW		2.72 MW				

Note: * with tax credit of 35% ** with tax rebate of 24.5%

Feed-in tariff aggregate limits: Oahu 60 MW; Hawaii Island 10 MW; Maui, Lanai, Molokai combined 10 MW

Source: Hawaii State Energy Office, 2017

A.1 Kauai Island

The state set renewable portfolio standards for electricity beginning at 30% of net sales by December 2020, increasing to 100% of net electricity sales by 2045. Kauai Island provides useful insights into the development of solar.

With an area of 1,456 km^2 Kauai is the fourth largest of the main Hawaiian Islands and has a population of 72,000. There were 30,672 housing units in 2016 and the median household income was US$65,101 (US Census). Home ownership sits at around 48%. The largest town is Kapaa with a population of around 9,500. Tourism is the island's largest sector. Approximately 90% of businesses employ fewer than 20 employees. Accommodation/food services account for about 26% of the labour force, followed by government (15%), retail (15%) and agriculture (3%).

The Hawaii Clean Energy Initiative worked with the US Department of Energy's NREL to assess the solar resources available on the island of Kauai (Helm and Burman 2010). NREL coordinated its efforts with the KIUC to determine the technical feasibility of increasing the contribution of solar renewable energy for electricity generation. Hourly satellite solar radiation information was used to determine the amount of annual solar energy that can be produced from PV for the designated area.

A sample assessment was done using the solar resource and agricultural layers to determine the potential amount of energy that can be produced from ground-mounted systems and rooftops available for PV. The study shows that there is potential to generate enough energy to cover the peak load as reported for Kauai in 2007.

In addition, the assessment showed that Kauai has solar resources that vary from a low of 5.25–5.5 kWh/m2/day to a high of 6.25–6.50 kWh/m2/day – similar to the solar resource in the Cook Islands between September and March. With this, the overall ground-mounted PV-power-production potential was estimated at 1,240 GWh/yr on an area totalling 10.4 km^2 and an installed capacity of 830 MW. The rooftop PV-power potential, significantly smaller than the ground-mounted potential, was estimated at 15.9 GWh/yr on a total area of 136,412 m^2 and installed capacity of 11 MW.

KIUC is a non-profit, locally owned, generation, transmission and distribution organisation that serves 33,000 accounts. KIUC is a recognised leader in the use of renewable energy and seeks to produce 70% of its electricity from renewable sources by 2030. Total renewable energy in service is 83.9 MW (42%) of which 66.6 MW (79.3%) is solar. A further 25 MW of solar is under construction and 12 MW is under consideration. Koloa solar power installation (12 MW) went on line in 2014. It is the largest array, costing US$40 million; it supplies nearly 6% of the island's electricity and reduces KIUC's oil consumption by 1.7 million gallons per year. The Anahola array (12 MW) was completed in 2015 at a cost of US$54 million. KIUC has 4.5 MW of battery storage on the grid.

Recently, a further 6 MW of storage with a lithium-ion battery system was installed at its Anahola array. Under the terms of the deal with Tesla, KIUC will buy power for 20 years at the rate of 13.9 ¢/kWh. The 52 MWh battery system is designed to feed up to 13 MW of electricity into the gird. The cost is lower than buying power from diesel-fuelled power plants and below the charge paid by customers elsewhere in the state. Rooftop systems have been installed by 3,500 residential customers, out of a total of about 33,000 (KIUC 2017).

Table 35 Features of KIUC Electricity Business

Feature	Details
Number of meters	33,562
Square miles served	562
Transmission and distribution	1,400 miles of 57.1 kV and 12.47 kV distribution lines
Employees	151
Total generating capacity	125 MW
Residential solar rooftop	3,273
Reliability	99.96% each year, 2014–2016
Use of renewable power	At least 90% in daylight hours on most sunny days

Source: http://website.kiuc.coop/about

With the development of solar PV, the island's grid is often saturated with midday generation, particularly on sunny days when renewables can supply up to 90% of the island's load. With nowhere to export surplus power, KIUC needs solar plants with battery storage. The solar-plus-storage model avoids the need for fossil-fuel peakers. In 2015, KIUC partnered with SolarCity to develop a 13 MW PV system with a 13 MW/52 MWh Tesla Powerpack lithium-ion battery storage system. SolarCity will sell power to KIUC at 13.9 ¢/kWh. The plant is expected to begin operations in 2017.

KIUC has partnered with AES Distributed Energy to build a solar-plus-storage peaker plant. If approved by regulators the project will combine 28 MW of solar capacity with 20 MW of 5-hour duration batteries. AES will operate the system and sell power to KIUC at 11 ¢/kWh. The facility is expected to be operational in late 2018.

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