D4 – Final Report and Model for Kosrae Utilities Authority (Kosrae)

Assessment of Variable Renewable Energy (VRE) Grid Integration, and Evaluation of SCADA and EMS system design in the Pacific Island Counties

Report for the Pacific Power Association and the World Bank
Selection # 1238727

WORLD BANK GROUP

ESMAP
Energy Sector Management Assistance Program

ED 10514 | Issue Number 3 | Date 23/05/2019

Customer:

The World Bank

Customer reference:

Selection # 1238727

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Contact:

Graeme Chown
Ricardo Energy & Environment
Gemini Building, Harwell, Didcot, OX11 0QR, United Kingdom

t: +44 (0) 1483544 944

e: graeme.chown@ricardo.com

Ricardo-AEA Ltd is certificated to ISO9001 and ISO14001

Author:

Graeme Chown, TNEI, AF-Mercados

Approved By:

Trevor Fry

Date:

23 May 2019

Ricardo Energy & Environment reference:

Ref: ED10514- Issue Number 3

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1 Introduction

The Pacific Power Association, in consultation with The World Bank, has identified the need for VRE integration assessment and SCADA-EMS system design to support the development of the nascent renewable energy sector in the region. This report has been developed as a part of the "Assessment of Variable Renewable Energy (VRE) Grid Integration and Evaluation of SCADA and EMS system design in the Pacific Island Counties" project.

The assignment consists of four interrelated tasks and each section of this report corresponds to a specific task. The first section is on the grid integration and planning studies and in this task, the consultants used the available power system data, validated the dynamic characteristics of the existing generators, and collaborate with utilities to build and populate several models for specific islands. In this task, the consultants identified the grid stability and reliability issues for different VRE penetration levels and different demand scenarios.

The second section is on the assessment of energy storage applications in power utilities. The main objective of this task was to assess the interest and cost-effectiveness of the energy storage systems, and the role that it can perform as grid support including identification and probable solutions to implementation challenges that may arise.

Based on best practices adopted in other countries, a grid code has been developed for the Kosrae Utilities Corporation and this is available in Appendix 1 of this report. The grid code was written after assessing the requirements relating to voltages and frequency range of the island, understanding different options to integrate Renewable Energy sources into the system and how Renewable Energy generators could respond to grid disturbances. In the grid code, special emphasis was given to state the grid support capabilities that are expected from Renewable Energy generators.

The fourth section presents the results of the assessment of the needs for Supervisory control and data acquisition (SCADA) and Energy Management System (EMS).

2 Task 1: Grid Integration and Planning Studies

Grid integration and planning studies have been conducted as part of this project to assess the effect of different penetrations of variable renewable energy (VRE) generation on the operation and stability of specific networks within a number of the Pacific Island countries.

The Pacific Island country (PIC) networks each have underlying grid stability issues, caused primarily because these are small island networks with very little inertia and support to maintain system stability and frequency. The generation that is connected to these networks often does not have the appropriate control systems in place to manage behaviour during disturbances; and this also impacts the overall stability of these grids.

The move towards a more sustainable and reliable power sector will result in more renewable generation technologies connecting to these networks. It is the purpose of these studies in Task 1 to:

- Assess the operational and stability characteristics of the existing networks
- Assess and understand the capability of each of the studied networks to accommodate renewable, intermittent generation;
- Identify operational limitations and optimal range of power generation mix between existing and new generation to prevent adverse impacts; and
- Provide recommendations on strategic reinforcements and other methods of increasing VRE penetration.

The networks studied in Task 1 are:

Pacific Island Country	Network under Study
Samoa	Upolu
Federated States of Micronesia	Chuuk
Federated States of Micronesia	Kosrae
Tonga	Tonga
Federated States of Micronesia	Pohnpei
Marshall Islands	Majuro
Tuvalu	Funafuti

2.1 Power system study methodology

The following steps have been taken to assess each of the networks under study:

1) Development and finalisation of base case network models using existing Digsilent network model files where available, or developing Digsilent models from data collected from utilities.

2) Perform load flow studies to assess the steady state performance of the power system. The following assessments will be made:
   - The loading conditions of network components in the system (measured as a percentage of rating) with the given demand level. Network components with loading conditions above 90% of the specified rating will be reported.
   - The voltage profile across the network (measured in per unit) with the given demand level. Nodes with a recorded voltage magnitude above 1.10pu and below 0.90pu will be reported.
   - Network capability to meet a scaled load demand of 105% or 110% (depending on size of network) of existing load demand level. Any overloads and voltage violations will be reported.

3) Perform contingency and switching operation studies to assess the steady state performance in each power system under credible outage or switching operation conditions. The contingency studies will be performed on mesh networks, while the switching operation studies will be applied to the radial network with switch devices on or between feeders. The following assessments will be made:
    - The loading conditions of network components in the system (measured as a percentage of rating) under the credible outage or switching operation conditions. Network components with loading conditions above 90% of the specified rating will be reported.
    - The voltage profile across the network (measured in per unit) with the given demand level under the credible outage or switching operation conditions. Nodes with a recorded voltage magnitude above 1.10pu and below 0.90pu will be reported.
    - Network capability to meet a scaled load demand of 105% and 110% of existing load demand level under credible outage or switching operation conditions. Any overloads and voltage violations will be reported.

4) Perform fault studies to assess fault levels at power plant busbars and those nodes with switches in each power system. The following assessments have been made:
    - Three phase fault levels;
    - Single phase to ground fault level;
    - Make fault current at 10 ms and Break fault current at 50 ms for a 50 Hz system; and
    - Make fault current at 12 ms and Break fault current at 60 ms for a 60 Hz system.

5) Perform stability studies to determine stability performance in each power system for credible dynamic events and contingencies. The studies are carried out based on the given load demand level in the system. The following assessments have been made:
    - Frequency and voltage response of the system subsequent to the loss of the largest generating unit in the system.
    - Frequency and voltage response of the system subsequent to the loss of the feeder with the largest MW load demand.
    - Rotor angle and voltage stability of the system subsequent to a three phase fault applied on feeders followed by tripping of the feeder with 150 ms delay. A fault will be applied respectively on the feeders with the smallest and the largest MW load demand.
    - Frequency and voltage response of the system subsequent to the MW output change from the PV sites. The MW output of all PV sites in the system will be assumed to drop from maximum MW output level down to 0 MW output level within 10 seconds. After 20 seconds delay the MW output of all PV sites in the system will be assumed to rise from 0 MW output level to the maximum MW output level within 10 seconds.

Steps 1 – 5 as listed above forms the basis of the study of each network to understand their operational characteristics and any limitations. Following this, the penetration of renewable generation connected to the network has been increased in suitable increments (depending on the size of the network) and the following steps performed to assess the network capability to accommodate these renewables.

To assess and identify maximum renewable generation capacity that can be integrated into the utility power grid, the power system model is set up as follows:

- Existing network topology.
- The assumed maximum load demand level, which could be 3% ~ 5% higher than the existing maximum load demand level if the system has adequate network capacity.
- Renewable generation capacity (PV generation) considered to be at 5%, 10%, 15%, and 20% of total installed generation capacity in the system. New renewable generation sites could be distributed across the system.
- Renewable generation is fully dispatched in the considered operational scenarios. The conventional generators, however, are dispatched based on merit order to balance the

rest of power mismatch in the system. The calculated spinning reserve capacity shall be more than 10% of the demand level.

The following studies have then been performed:

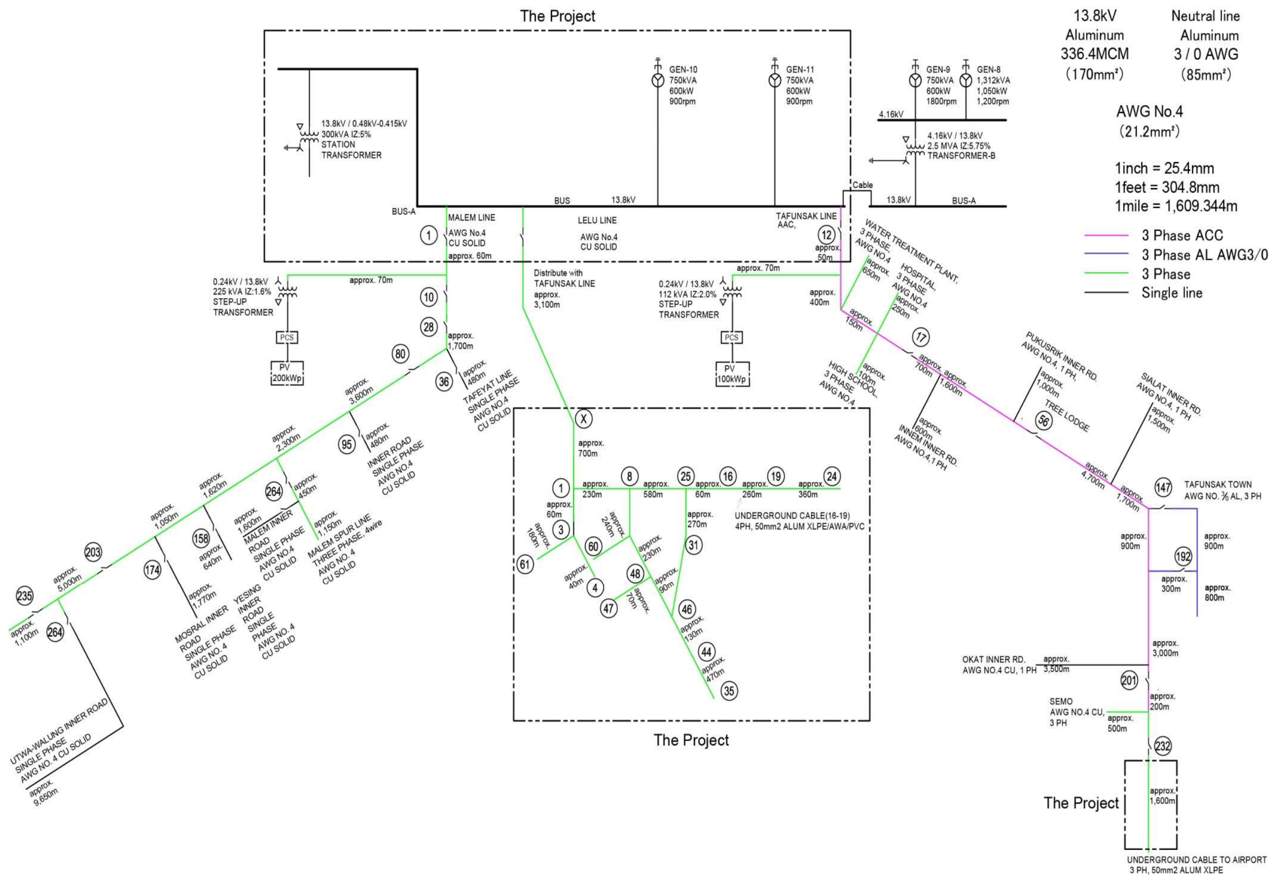
6) Stability simulations to assess system frequency response for the two events:
   - The sudden loss of the largest generating units on line
   - The drop of MW output from all PV site with 10 seconds
     - If the minimum frequency deviation of the system for any event is within 2% of nominal frequency, it indicates that the system has the capability to integrate the amount of assumed renewable generation capacity.
     - If the minimum frequency deviation of the system for any event is greater than 2% of nominal frequency, then the following steps should be taken:
   - Switch on one of the conventional generators connected to the system and assume that it is operated at its minimum MW output. To balance the power mismatch in the system, the MW output of other conventional generators is adjusted accordingly.
   - Perform stability simulations again for the same event(s) to determine if the system frequency is within 2% of nominal frequency.
     - If the frequency is now within the 2% threshold, this indicates that the system has the capability to integrate the amount of assumed renewable generation capacity with the support of more spinning reserve from conventional generators.
     - If the frequency remains above the 2% threshold, this indicates that the system cannot suitably integrate the amount of the assumed renewable generation capacity. Battery storage is a potential solution (and this is studied in more detail in Task 2).

2.2 Kosrae Network, Federated States of Micronesia

Kosrae is another of the four states within the Federated States of Micronesia. The utility company in charge of operating and managing the power grid in Kosrae is the Kosrae Utilities Authority (KUA). The network under study for this project is the KUA power network on Lelu Island. The network is a 60 Hz 4-wire system with a backbone network of 13.8 kV whereby there is a primary power station on the island which outputs at 13.8 kV and three separate distribution circuit feeders carry power around the island.

The network SLD is provided in **Error! Reference source not found.** and shows the three feeders as supplied by the power station at Tofol.

Figure 2-1: Single line diagram for the Kosrae power system



The existing Tofol power station comprises three diesel generators. A new power station is being constructed which comprises two diesel generators connecting in at 13.8 kV and a further diesel generator, funded by the World Bank, is being installed at the existing power station. **Error! Reference source not found.** shows the schematic diagram of the existing Tofol power station after installation of the World Bank generator. There are various solar installations across the island. The generation portfolio of the island is provided in **Error! Reference source not found.**.

Figure 2-2: Schematic Electrical Diagram of Tofol Power Station

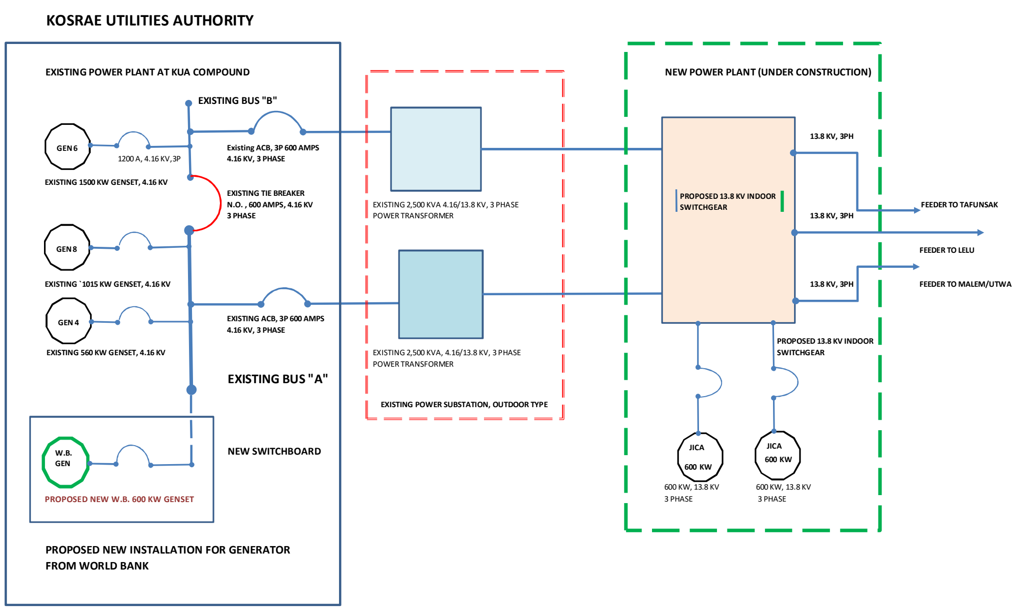


Table 2-1: Kosrae installed generation

Name	Capacity (kW)	Type
Tofol DG4	560	Diesel
Tofol DG6	1500	Diesel
Tofol DG8	1015	Diesel
Tofol DG4 (new WB)	600	Diesel
New PS DG1 (JICA)	600	Diesel
New PS DG2 (JICA)	600	Diesel
KUC Site	200	PV
Governor’s building	100	PV
5 x small sites	45.4	PV

In addition to the PV sites listed in the table above, there are plans to connect more solar PV generation to the island, totalling around 500 kW by 2019 (then 2MW by 2023). There are no plans to connect wind or hydro due to lack of resource.

As can be seen from the table, the installed generation capacity of the Kosrae network will be 5,220.4 kW on completion of the new diesel generating units. The maximum demand of the network is around 1100 kW, and the minimum demand is 380 kW. The maximum and minimum demands were measured in January 2017.

2.2.1 Power system data and assumptions

The data made available for the power system studies of the Kosrae utility network is described in detail in the Data Collection Report (D3 – Data Collection Report, April 2018). Data that was not provided and therefore has to be assumed includes:

- Diesel generator AVR and governor dynamic models – dynamic models have not been provided for any of the diesel generators. The data for these will be assumed based on typical data of similar generators of the same/similar size.
- Grid code, local operational requirements – no grid code or local operational requirements provided, however there is a policy document to provide guidance to consumers. Typical industry standards are assumed for operational limits.

2.2.2 Summary of Power System Studies and Scenarios

The following table provides a summary of the power system studies performed on the Kosrae network, and the different network conditions/scenarios considered.

Study	Scenarios
Load Flow	Maximum Demand 5% Load scaling, 10% Load scaling
Load Flow	Minimum Demand
Fault Level	Maximum Fault Level Conditions
Stability Study – Existing System	Loss of largest generator, loss of largest feeder, 3ph fault and feeder trip, Increase/decrease of PV generation
Stability Study – 500kW Renewable Generation Penetration, 2 diesel generators dispatched	Increase/decrease of PV generation
Stability Study – 500kW Renewable Generation Penetration, 3 diesel generators dispatched	Loss of largest generator, loss of largest feeder, Increase/decrease of PV generation
Stability Study – 500kW Renewable Generation Penetration, 3 diesel generators dispatched – more even output	Loss of largest generator

2.2.3 Power system study results

The subsections to follow provide the results of the power system studies performed on the Kosrae network.

2.2.3.1 Load flow studies

Load flow studies were performed on the Kosrae network model. The studies consisted of maximum and minimum demand scenarios, and demand scaling of the maximum demand scenario to understand the implications of load growth.

The scenario results can be summarised as follows:

Maximum demand scenario

The table below presents the results of the maximum demand load flow studies for the base case (current demand level) and then two stages of load scaling, 5% and 10%.

Table 2-2: Maximum demand scenario load flow results

Demand Level	Maximum thermal loading (%)	Maximum voltage (pu)	Minimum voltage (pu)
Base Case	7.63	1.00	0.9762
5% Load Scaling	8.02	1.00	0.9749
10% Load Scaling	8.41	1.00	0.9736

It can be seen from the results that there are no thermal or voltage issues in any of the cases, with maximum circuit loading ranging from 7.6 – 8.4% and the voltage profile remaining reasonably close to nominal throughout. There is adequate headroom for load growth on the island, even beyond the 10% load scaling studied here. The network voltage profile does not vary considerably with the gradual increase in demand.

Minimum demand scenario

The table below presents the results of the minimum demand load flow studies for the current minimum demand level.

Table 2-3: Maximum demand scenario load flow results

Demand Level	Maximum thermal loading (%)	Maximum voltage (pu)	Minimum voltage (pu)
Base Case	3.93	1.00	0.9927

The maximum loading on the network is recorded as less than 4% under minimum demand conditions. The maximum and minimum voltages are very close to nominal suggesting there are no operational issues.

2.2.3.2 Switching studies

The radial configuration of the network prevents any contingency analysis or switching studies being performed for this network. In the event of a fault on any of the three feeders on the system, the downstream network will be impacted and lose supply. The impact on the upstream network will depend on the protection configuration and settings along the feeders.

2.2.3.3 Fault level studies

The fault level studies were carried out assuming all generation connected to the system is switched on, thus providing conditions for maximum fault level. Three phase and single-phase-to-ground faults were studied. **Error! Reference source not found.** shows the results for both 3 phase and single-phase-to-ground faults.

Table 2-4: Maximum fault level results for Kosrae

Fault Level	kA	Busbar	Voltage Level
Three Phase ip	14.14	1000 BUS_A/B	13.8
Three Phase Ib	3.17	1000 BUS_A/B	13.8
Single Phase ip	17.01	1000 BUS_A/B	13.8
Single Phase Ib	4.87	1000 BUS_A/B	13.8

The fault level at the main power station has the highest fault level in all cases, which is to be expected. There were no individual switchgear or circuit breaker ratings provided for the network and so a clear determination of the fault levels being within acceptable limits cannot be made at this stage. During the Inception Mission, a maximum short circuit capacity of 12.5 kA (break) for the 13.8 kV system was quoted. It is believed that switchgear with the short circuit capacity of 12.5 kA will be adequate to interrupt and withstand the fault currents in the 13.8 kV system. Some standard switchgear ratings (typically used in 60Hz US style systems) for different voltage levels are provided in **Error! Reference source not found.** for reference.

Figure 2-3: Typical Switchgear Ratings from 4 – 38 kV (Source: Siemens USA)

ANSI C37.06-1987 (and 1964 and 1979) Circuit Breaker Ratings ("Constant MVA" Rating Basis)

Historic "MVA Class"	Max kV	Rated kA	Max kA	Range Factor	Continuous Current	Dielectric (kV)		Close & Latch (kA)	
						60Hz	BIL	rms (1.6KI)	Peak (2.7KI)
250	4.76	29	36	1.24	1200 2000	19	60	58	97
350	4.76	41	49	1.19	1200 2000 3000	19	60	78	133
500	8.25	33	41	1.25	1200 2000 3000	36	95	66	111
500	15	18	23	1.30	1200 2000	36	95	37	62
750	15	28	36	1.30	1200 2000 3000	36	95	58	97
1000	15	37	48	1.30	1200 2000 3000	36	95	77	130
1500	38	21	35	1.65	1200 2000 3000	80	150	56	95

2.2.3.4 Stability studies

The voltage and frequency response of the system (maximum demand scenario) was assessed for three distinct events:

1) Loss of the largest generator on the system;
2) Loss of the largest feeder (largest MW loading) on the system; and

3) Reduction in PV output from maximum MW to 0 MW within 10 s then increase back up to maximum output from 0 MW after 20 s.

The voltage and rotor angle stability were assessed in the event of:

4) A three phase fault on the largest demand conductor followed by the tripping of the conductor after 150 ms.

Loss of largest generator

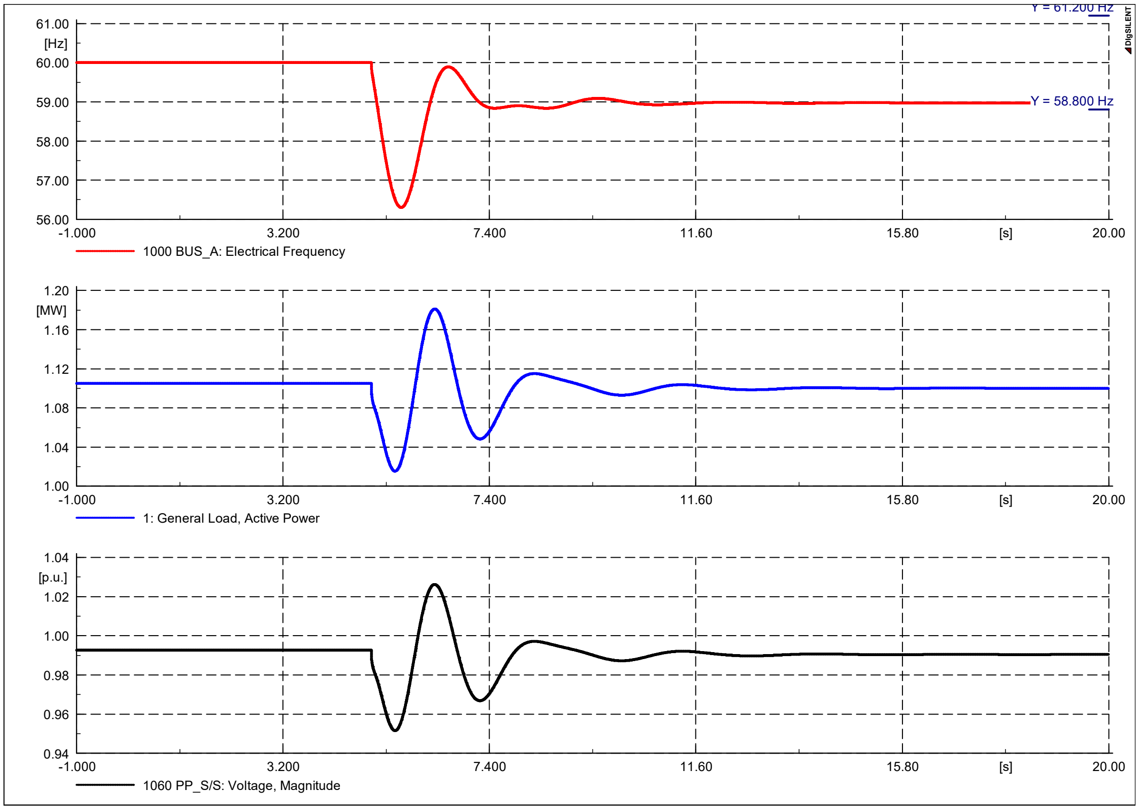
The generation mix assumed for this study in the first case is as shown in **Error! Reference source not found.**.

Table 2-5: Generation mix on Kosrae for Loss of Generator Study

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel	JICA DG1	2	0	0	0	0.0%
	JICA DG2	2	0	0	0	0.0%
	WB DG	3	0	0	0	0.0%
	DG 4	3	1	448.7	111.3	9.0%
	DG 6	3	1	375	1125	91.0%
	DG 8	3	1	0	0	0.0%
	Sub-total			**823.7**	**1236.3**	
Renewable	PV 1	1	1	160.0	0.0	0.0%
	PV 2	1	1	80.0	0.0	0.0%
	PV 3	1	1	36.3	0.0	0.0%
	Sub-total			**276.3**	**0.0**	
				1100	**1236.3**	**112.4%**

The maximum demand is assumed to be 1,100 kW based on information received at the Inception Mission and so the generation has been dispatched as such. The PV generation is operating at 80% of capacity and accounts for 25.1% of total generation output in the system. The two currently operational diesel generators make up the remaining capacity. DG4, as the largest of these generators, was tripped for the study and the voltage and frequency responses are shown in **Error! Reference source not found.**.

Figure 2-4: Voltage & frequency response to loss of largest generator



It can be seen from **Error! Reference source not found.** that the system cannot withstand the loss of the largest generator on the network in this operational scenario, as the frequency drops to almost 56 Hz before recovering to 59 Hz. Though DG6 has 1125 kW spinning reserve available, small inertia of the system still cannot prevent significant frequency drop following the loss of DG4.

Since it is not safe to run the system in this scenario i.e. with only 2 diesel generators in operation, remedial action is proposed here to run three of the diesel generators. So as to keep the generation/demand balance, these three generators must be run at a lower MW output. DG4 is set to run at 45% rated output, as shown in **Error! Reference source not found.**, while keeping 80% solar PV output. DG6 and DG8 are dispatched accordingly to meet the remaining demand requirements and the spinning reserve in the system is improved with the running of three generators.

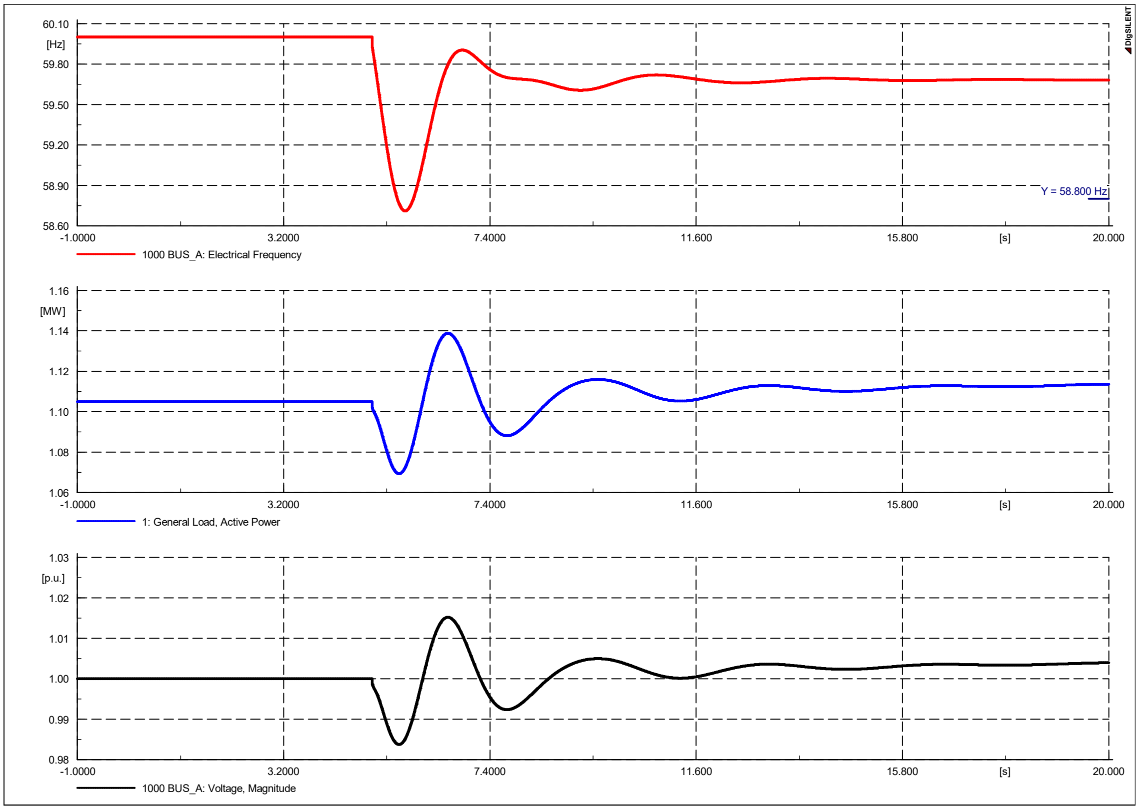
Table 2-6: Updated generation mix on Kosrae for Loss of Generator Study

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel	JICA DG1	2	0	0	0	0.0%
	JICA DG2	2	0	0	0	0.0%
	WB DG	3	0	0	0	0.0%

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Renewable	DG 4	3	1	162.0	398.0	26.1%
	DG 6	3	1	375	1125	73.9%
	DG 8	3	1	286.67	728.32	47.8%
	Sub-total			**537.0**	**1523.0**	
	PV 1	1	1	160.0	0	0.0%
	PV 2	1	1	80.0	0	0.0%
	PV 3	1	1	36.3	0	0.0%
	Sub-total			**276.3**	**0**	
				813.32	**1523.0**	138.5%

The same study as before, the loss of the largest generator on the system, was carried out again with this revised generation mix and the voltage and frequency responses are shown in **Error! Reference source not found.**.

Figure 2-5: Voltage & frequency response to loss of largest generator



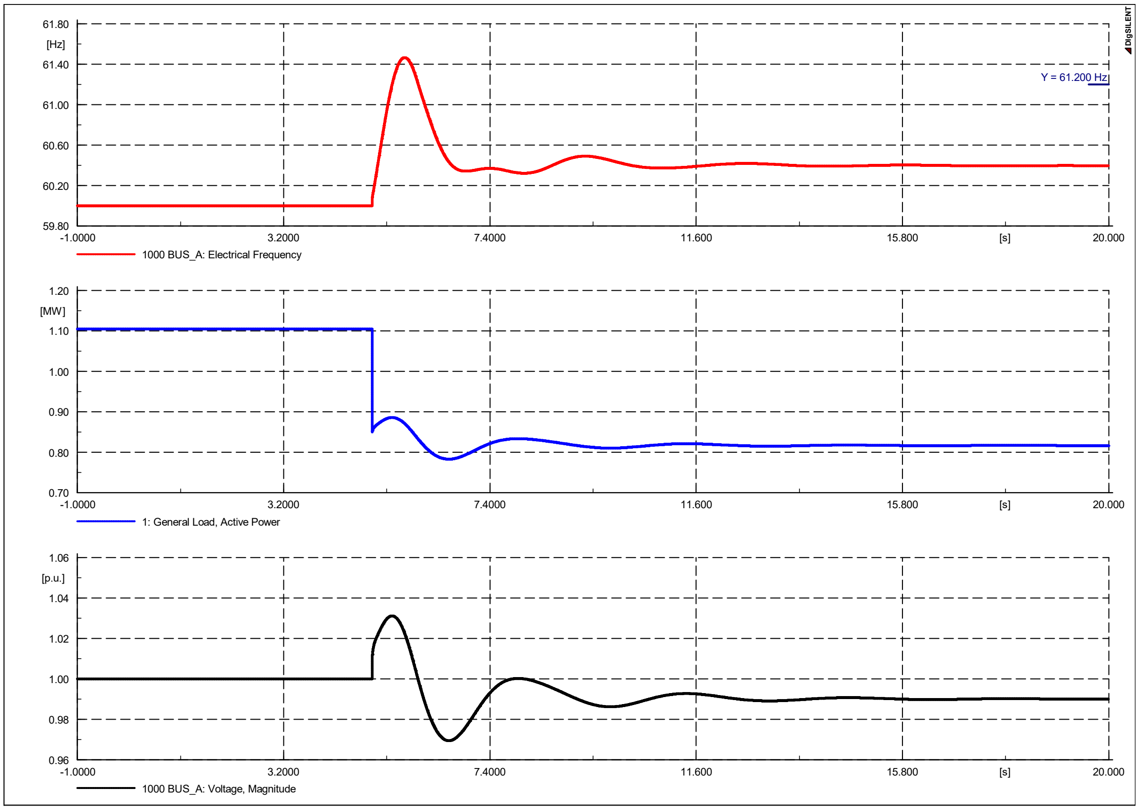
It can be seen from **Error! Reference source not found.** that the system is now capable of withstanding the loss of the largest generator, with a revised generation mix and profile. The system frequency is kept within the 2% lower limit of 58.8 Hz throughout the event and it settles on 59.7 Hz for the duration of the simulation.

The voltage drops to around 0.985pu from nominal as an immediate reaction to the event, but it recovers quickly and re-settles at around 1.01pu. The simulation results indicate that in order to maintain system frequency within acceptable range without incurring under-frequency load shedding, at least three diesel generating units shall be operated in this scenario.

Loss of largest feeder

The largest loaded feeder (feeder with the largest load demand) in the system is the “lne_1090_1100_1” circuit (LELU LINE). The feeder was tripped without a fault for the study and the voltage and frequency responses are shown in **Error! Reference source not found.**. The generation mix assumed in this case is the original portfolio as presented in **Error! Reference source not found.**.

Figure 2-6: Voltage & frequency response to loss of largest feeder

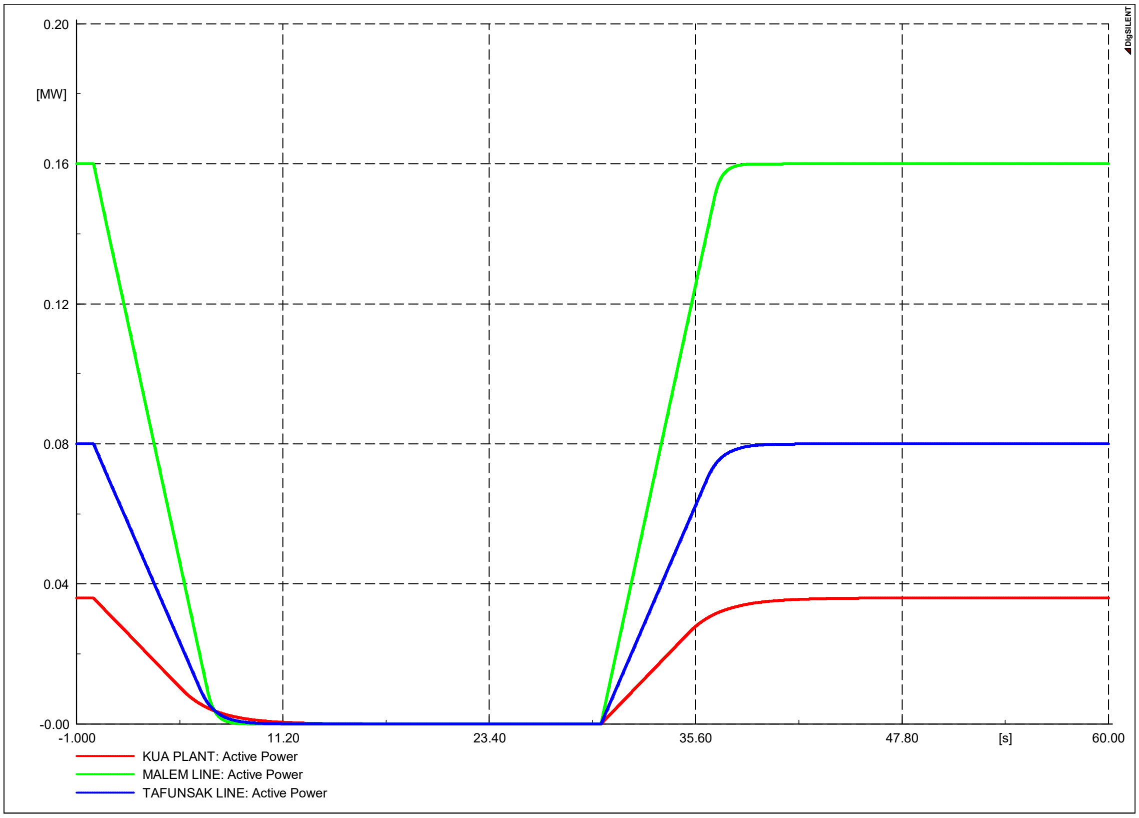


The feeder is tripped at 5 s and the frequency increases from 60 Hz, peaking 61.4 Hz and settling around 60.4 Hz which is within the 2% limit. The voltage remains within the acceptable ±10% limits, recording a minimum voltage of 0.97pu, coming to rest at 0.99pu 10 s after the loss of feeder event. The simulation results indicate that the system is capable of withstanding the loss of the largest feeder in this scenario without damaging integrity of the system.

Reduction/increase of PV output to/from maximum/0MW

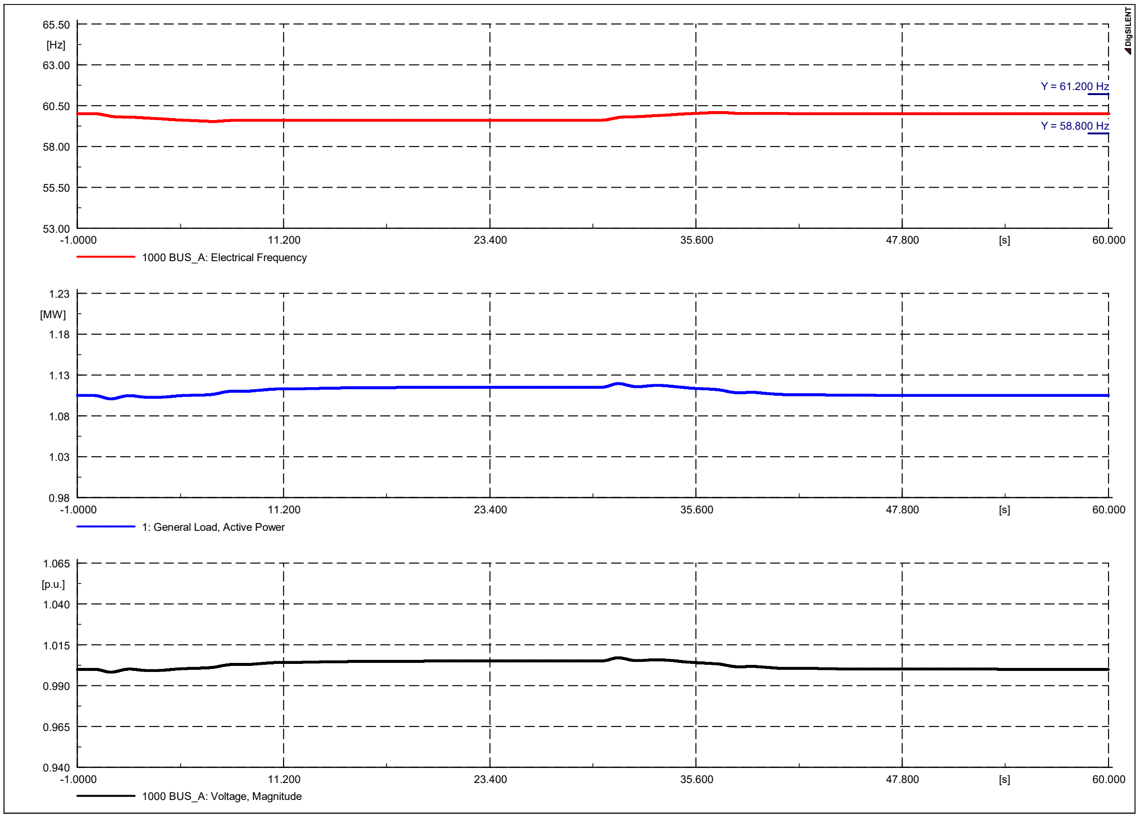
The PV sites connected to the island network were assumed to be operating at 80% output before being simultaneously reduced to 0 MW (to reflect sudden cloud coverage), and then returning to 80% output after 20 s. The generation mix assumed in this case is the original portfolio as presented in **Error! Reference source not found.** where the operational conventional generation is assumed to be operating at or close to their minimum output level. The PV output response for this study case is shown in **Error! Reference source not found.**.

Figure 2-7: PV MW output of all sites on Kosrae



The voltage and frequency responses are shown in **Error! Reference source not found.**.

Figure 2-8: Voltage and frequency response to changing PV MW output



As the MW output of the PV generators decreases, the frequency decreases accordingly. The frequency decreases from 60 Hz to 59.5 Hz for the duration that the PV sites are producing 0 MW of power. Once they ramp up again, the frequency ramps up in line with the increase of PV generation.

Three phase fault & subsequent tripping of demand feeder

A three-phase fault was simulated at the power station busbar (1000 BUS_A). The fault was cleared within 150 ms at which point Feeder 1 is tripped off. The voltage and rotor angle responses to these events are shown in **Error! Reference source not found.** and **Error! Reference source not found.** respectively.

Figure 2-9: Voltage and frequency response to fault and subsequent feeder trip

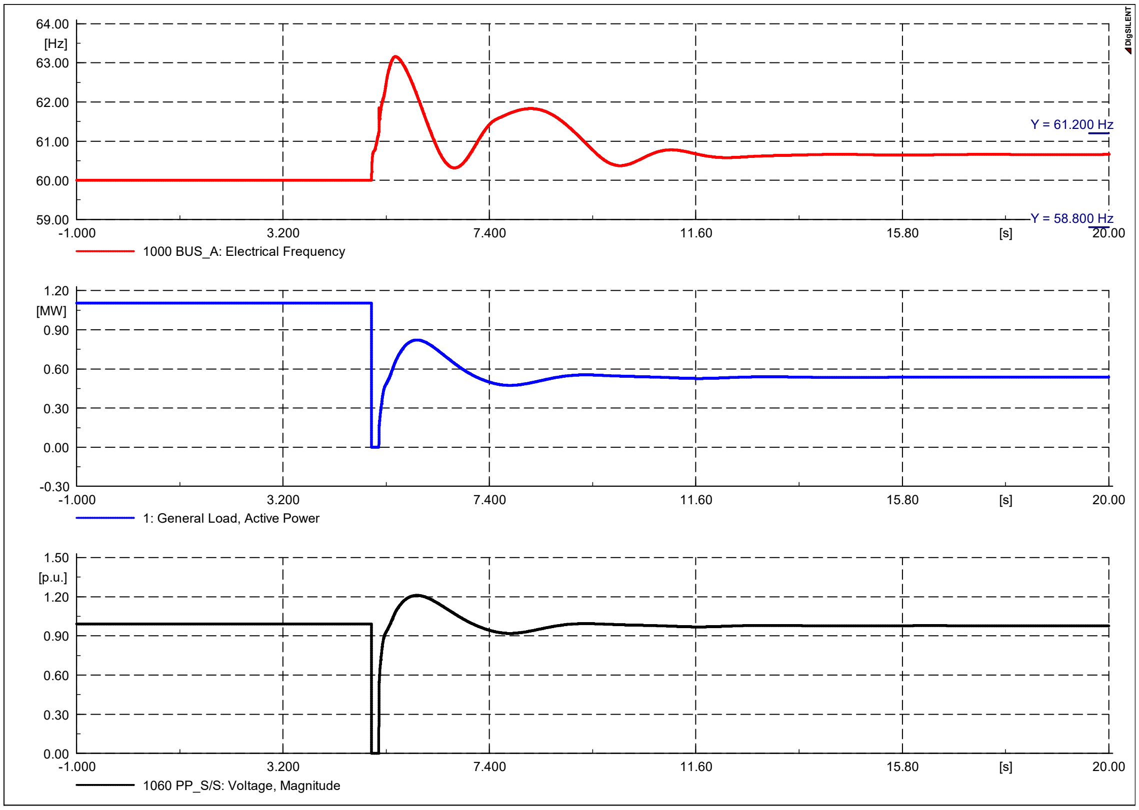
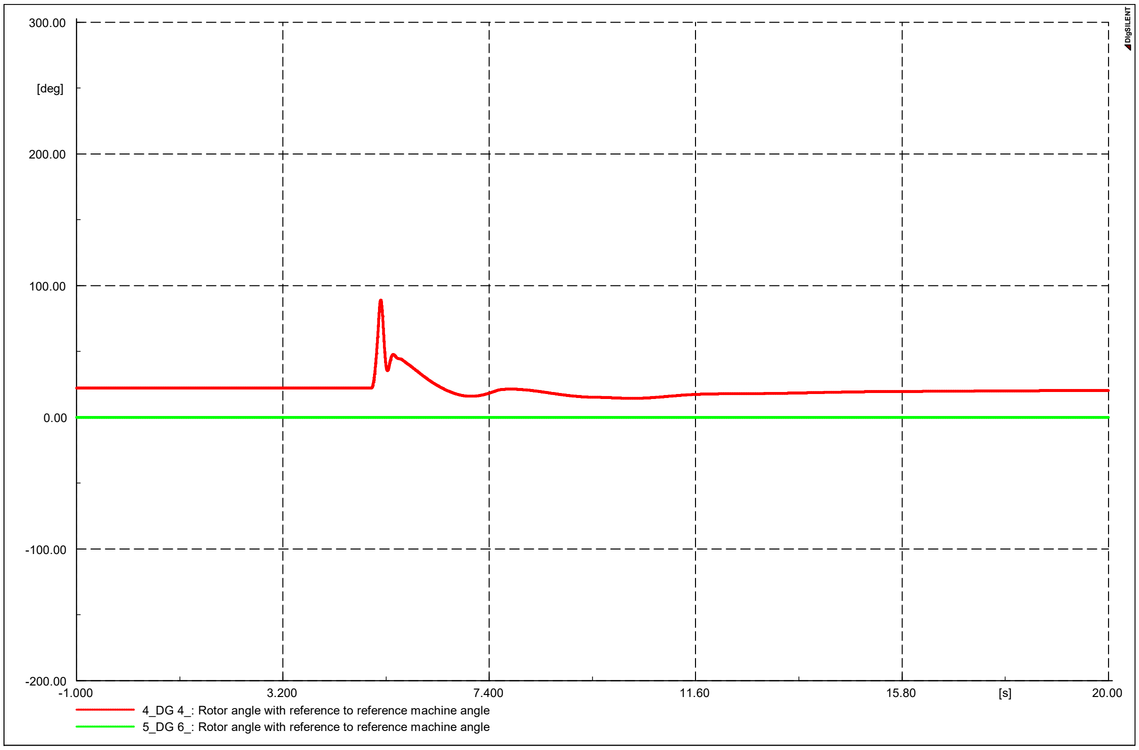


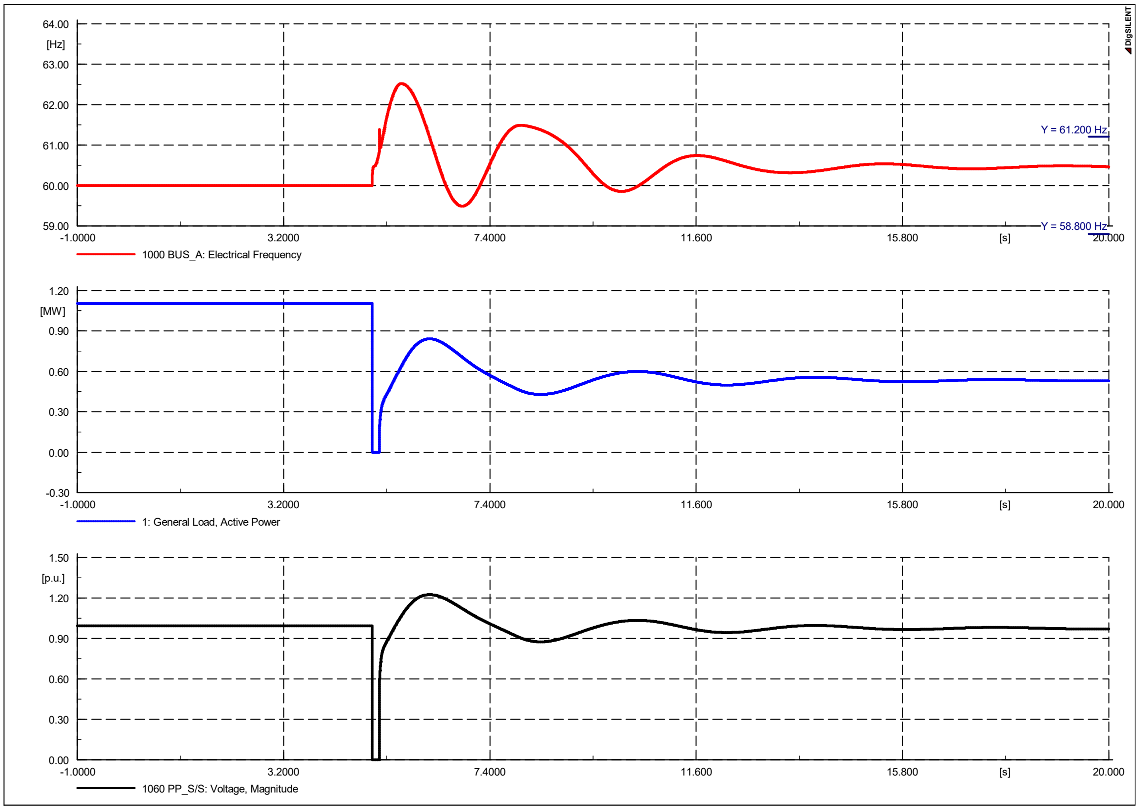
Figure 2-10: Rotor angle response to fault and subsequent feeder trip



Immediately after the fault, the voltage at the monitored bus (substation busbar) drops to 0 pu. Upon the tripping of Feeder 1, the voltage recovers very quickly (within a few milliseconds) to nominal value again. Both operational generators in the system remain in synchronisation without pole-slip subsequent to the fault event. System frequency peaks above 63 Hz after fault inception and then reduces down to stabilise at 60.6 Hz.

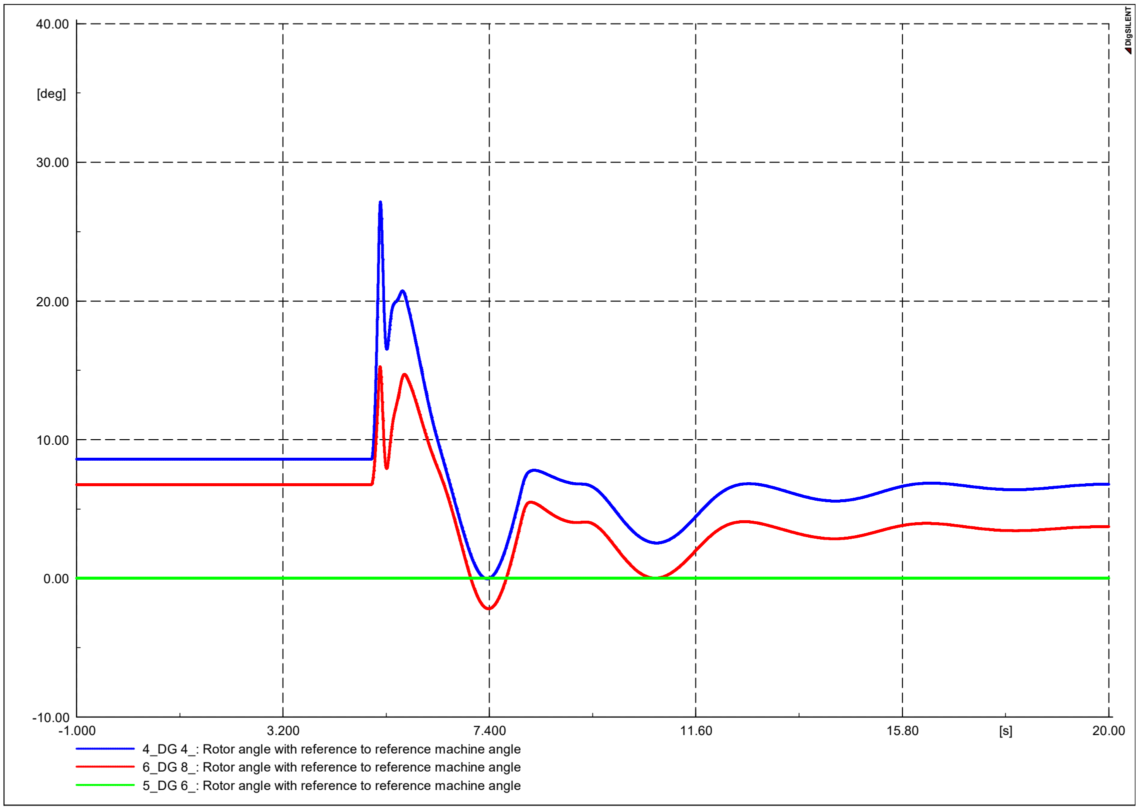
This study was carried out again for the generation portfolio presented in **Error! Reference source not found.** with three diesel generators online. This improves the frequency response somewhat, as seen in **Error! Reference source not found.** where the frequency peaks at 62.5 Hz.

Figure 2-11: Voltage and frequency response to fault and subsequent feeder trip



The rotor angle response improves significantly as shown in **Error! Reference source not found.** where the maximum angle shift is less than 30 degrees, where previously the rotor angle shift of the remaining generator is almost 100 degrees. The simulation results indicate that with one more generator switched on, system stability performance improves significantly.

Figure 2-12: Rotor angle response to fault and subsequent feeder trip



2.2.4 Increasing penetration of VRE

There are plans to increase the penetration of VRE on the Kosrae network, primarily from solar PV. An Asian Development Bank (ADB) study is ongoing which is looking at approx. 500 kW of additional PV located around the power plant, high school and airport. A number of studies have been performed to assess the capability of the network to accommodate this higher level of renewable generation, whereby the stability and response of the system are tested for the sudden increase and decrease of MW output, such as that experienced from cloud cover. The voltage, frequency and rotor angle responses are also tested (studies in Section **Error! Reference source not found.** are repeated) for the increased penetration of VRE to understand the impact on the stability of the system for other credible events.

2.2.4.1 Additional 500 kW of solar PV generation with two diesel units in operation

The following sections present the results which highlight the ability of the Kosrae power system to accommodate 500 kW of additional PV generation. The total generation mix assumed for this the subsequent studies is listed in **Error! Reference source not found.** where the operational conventional generation is assumed to be operating at minimum capacity to allow for the provision of spinning reserve and maximum demand has been scaled up by 5%. The PV generation is operated at 75% of the rated capacity, accounting for 52.4% of total generation output in the system.

Table 2-7: Generation mix on Kosrae for with additional PV generation

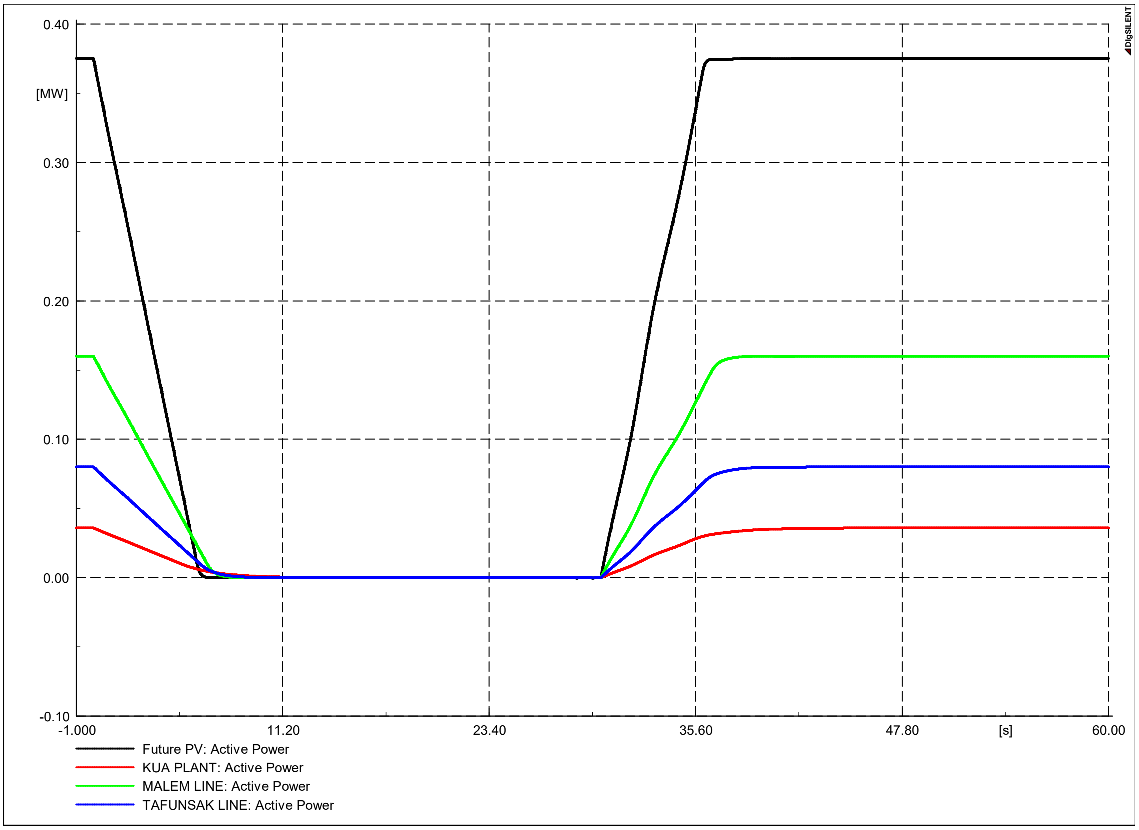
Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel	JICA DG1	2	0	0	0	0.0%

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
	JICA DG2	2	0	0	0	0.0%
	WB DG	3	0	0	0	0.0%
	DG 4	3	1	200.9	359.1	24.2%
	DG 6	3	1	375	1125	75.8%
	DG 8	3	1	0	0	0.0%
	Sub-total			**575.9**	**1484.1**	
	PV 1	1	1	150.0	0.0	0.0%
	PV 2	1	1	75.0	0.0	0.0%
Renewable	PV 3	1	1	34.1	0.0	0.0%
	New PV	1	1	375.0	0.0	0.0%
	Sub-total			**634.1**	0.0	
				1210	**1484.1**	**122.6%**

Reduction/increase of PV output to/from maximum/0MW

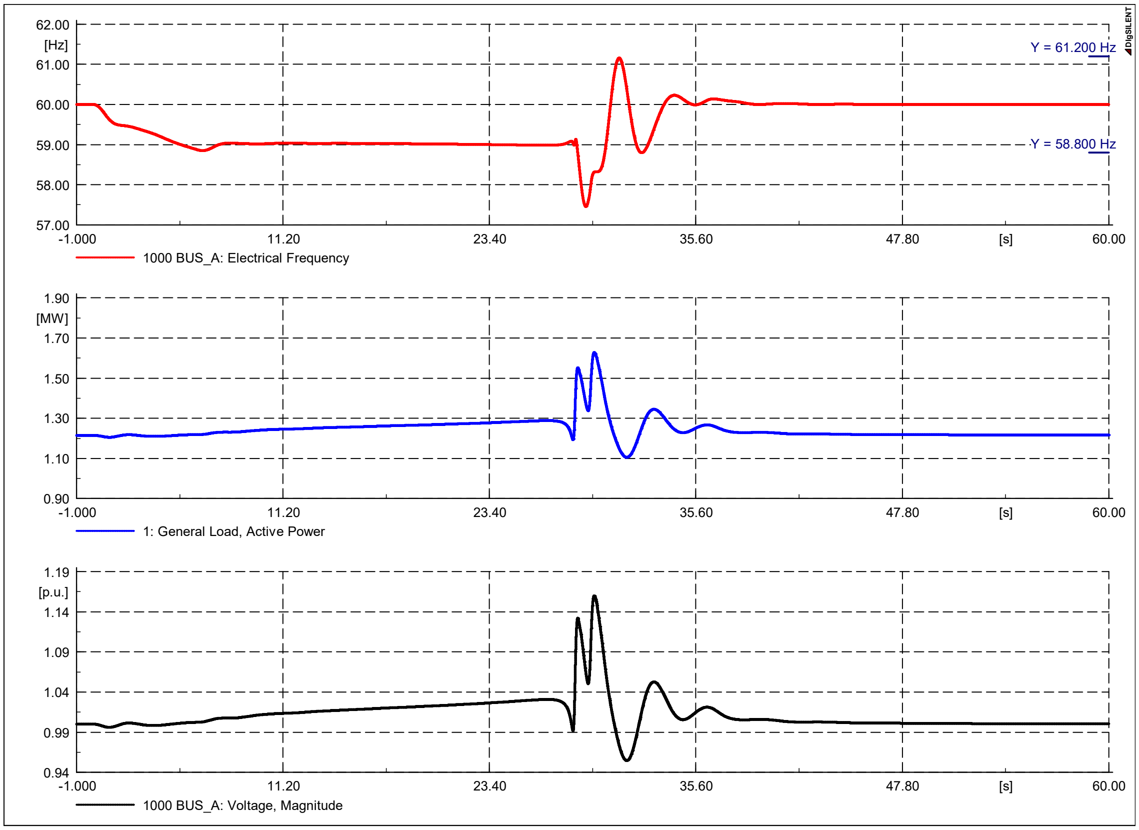
The voltage and frequency response of the addition of 500 kW of solar PV connecting to the Kosrae network is presented below. All PV sites were operated at the specified MW output before being simultaneously reduced to 0 MW, and then returning to the specified MW output after 20 s. The PV output response for the study case is shown in **Error! Reference source not found.**.

Figure 2-13: PV MW output of all sites on Kosrae



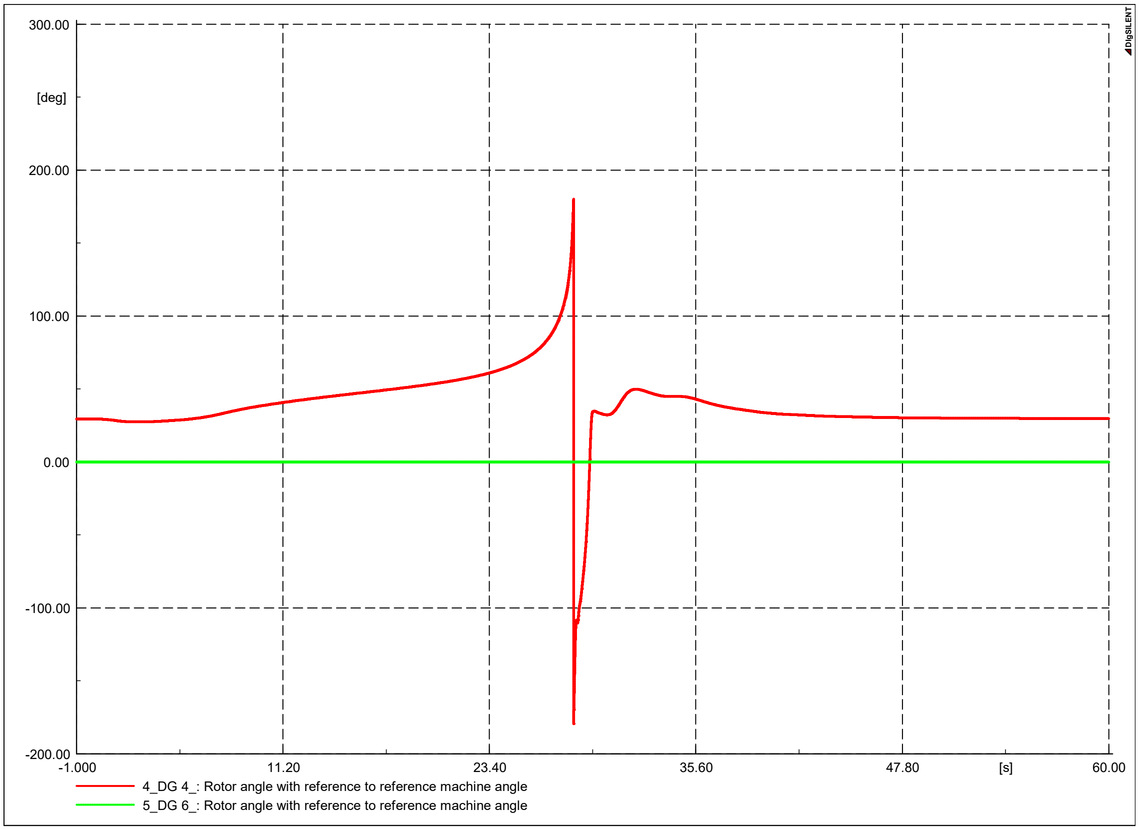
The voltage and frequency responses are shown in **Error! Reference source not found.**.

Figure 2-14: Voltage and frequency response to changing PV MW output



As the MW output of the PV generators decreases, the frequency decreases to around 59 Hz. When the PV output begins to increase again, there are some oscillations in frequency and voltage outside the allowable limits. The rotor angle of the diesel generators also swings considerably as shown in **Error! Reference source not found.**, indicating that the system cannot operate safely under these conditions.

Figure 2-15: Rotor angle response of diesel generators to changing PV MW output



2.2.4.2 Additional 500 kW of solar PV generation with three diesel units in operation (A)

The generation dispatch portfolio in **Error! Reference source not found.** has been updated to include three diesel generators providing more inertia and spinning reserve capacity in the system. The generation mix of the case is shown in **Error! Reference source not found.** below.

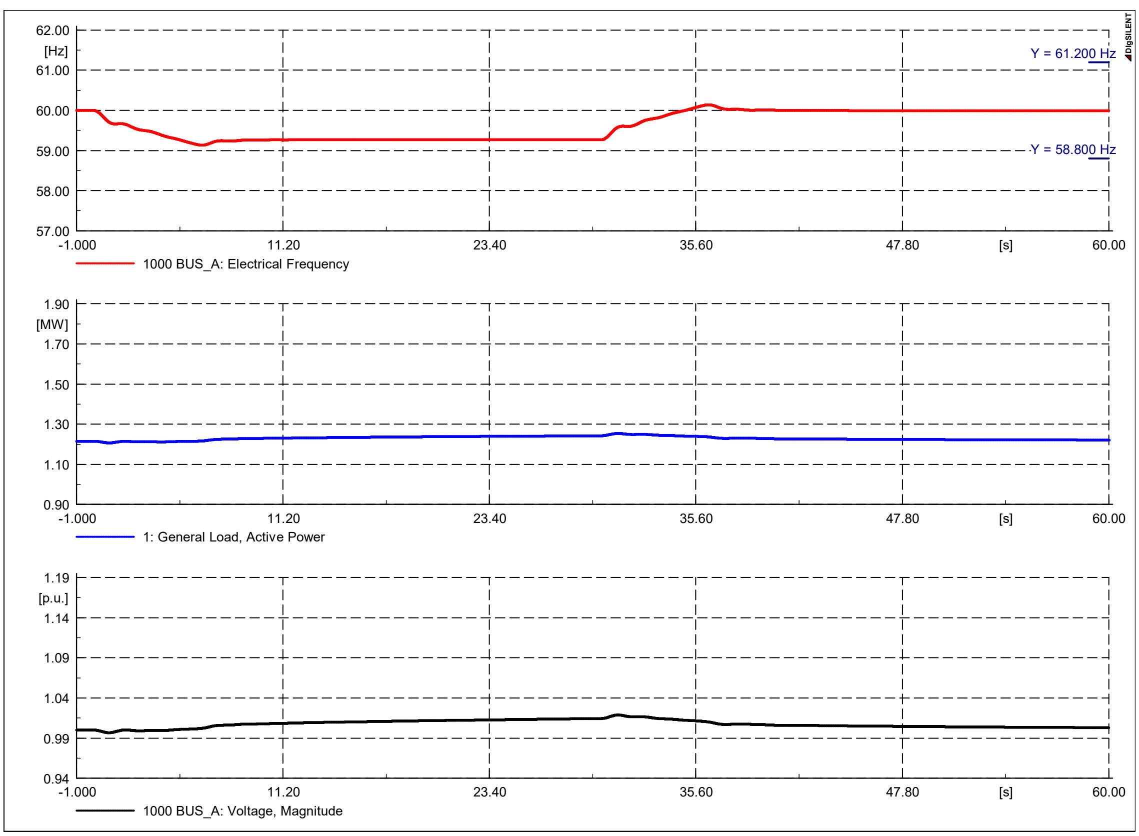
Table 2-8: Updated generation mix on Kosrae for with additional PV generation

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel	JICA DG1	2	0	150	450	21.6%
	JICA DG2	2	0	0	0	0.0%
	WB DG	3	0	0	0	0.0%
	DG 4	3	1	185.0	375.0	18.0%
	DG 6	3	1	240	1260	60.4%
	DG 8	3	1	0	0	0.0%

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
	Sub-total			**575.0**	**2085.0**	
Renewable	PV 1	1	1	150.0	0.0	0.0%
	PV 2	1	1	75.0	0.0	0.0%
	PV 3	1	1	34.1	0.0	0.0%
	New PV	1	1	375.0	0.0	0.0%
	Sub-total			**634.1**	**0.0**	
				1209.1	**2085**	**172.3%**

The voltage and frequency response with the revised generation dispatch is presented in **Error! Reference source not found.**. It can be seen that the response is much more stable and the frequency and voltage remain within the operational limits.

Figure 2-16: Voltage and frequency response to changing PV MW output

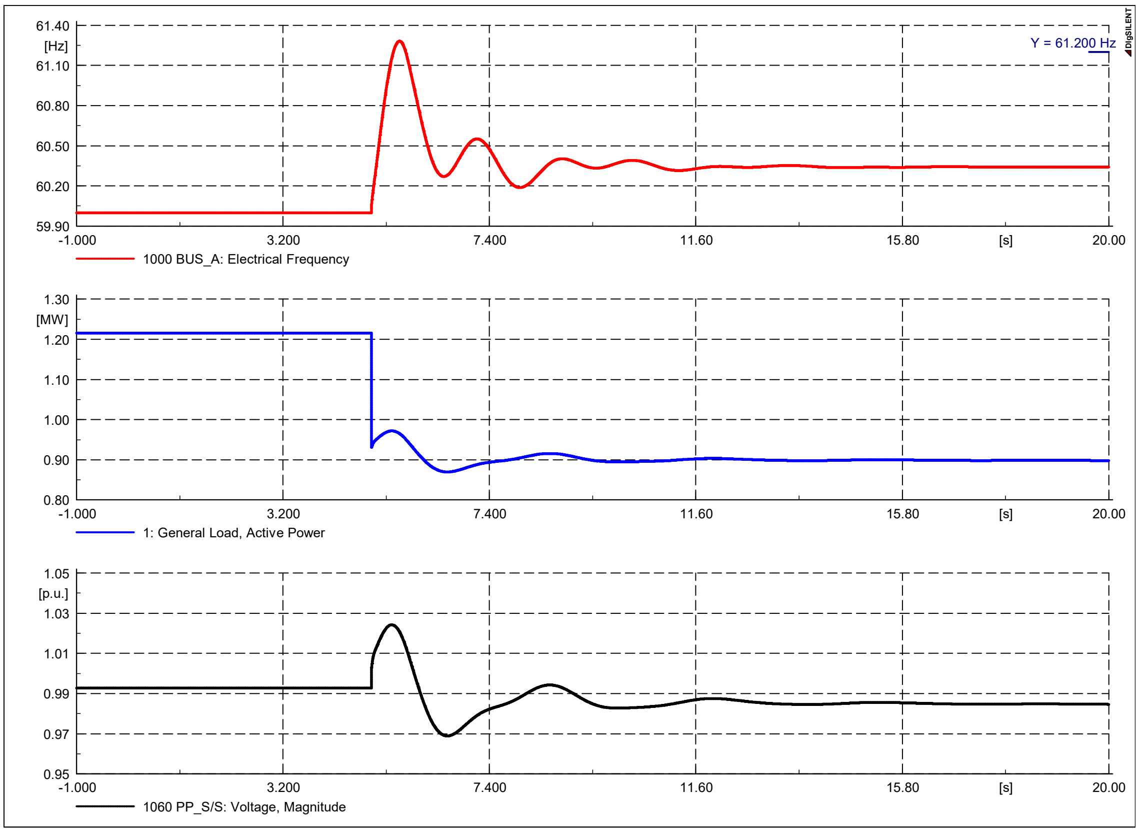


With this generation dispatch improving the response of the system to changes in the PV output, a number of other studies have been run to assess the capability of the system to respond to other credible events.

Loss of largest feeder

The largest loaded feeder (feeder with the largest load demand) in the system is the "lne_1090_1100_1" circuit. The feeder was tripped without any fault for the study and the voltage and frequency responses are shown in **Error! Reference source not found.**.

Figure 2-17: Voltage & frequency response to loss of largest feeder

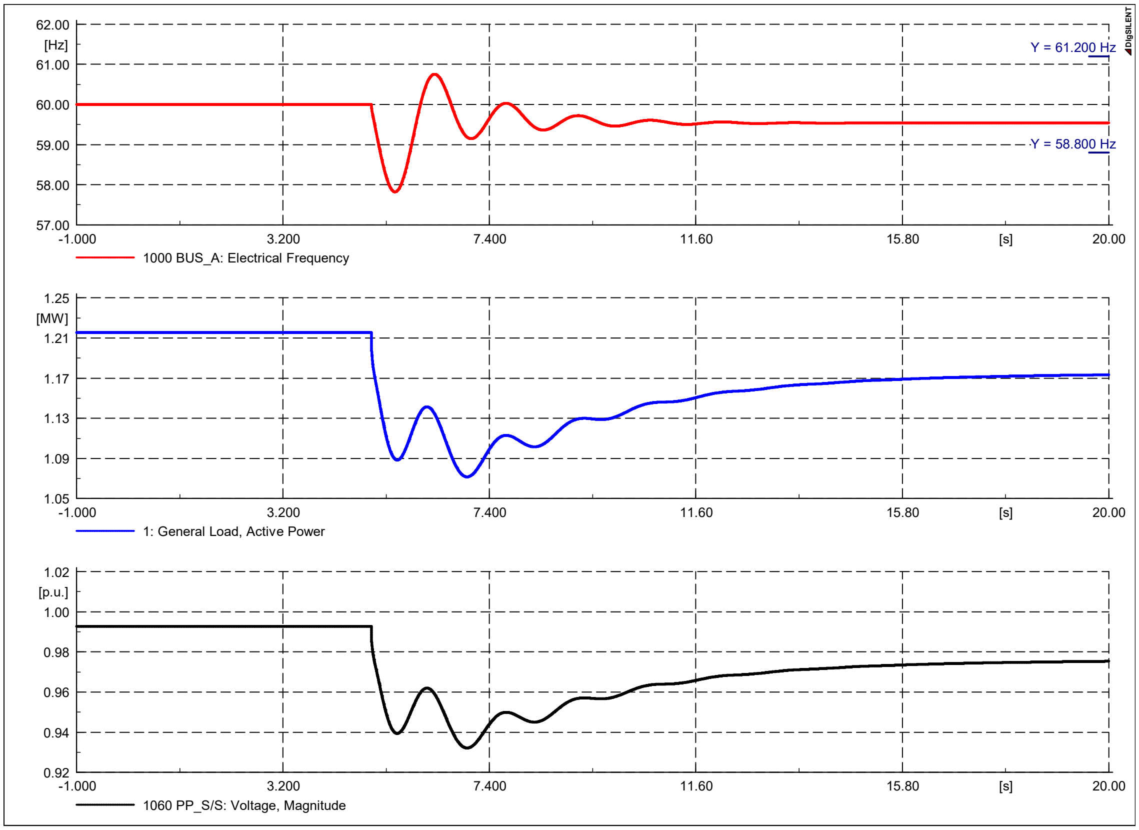


The voltage and frequency response show that the response is able to remain within the 2% limit. The voltage remains within the acceptable ±10% limits, recording a minimum voltage of 0.97pu, coming to rest at 0.99pu 10 s after the loss of feeder event.

Loss of largest generator

The loss of the largest generator on the system, according to the generation dispatch portfolio detailed in **Error! Reference source not found.**, causes the frequency and voltage responses shown in **Error! Reference source not found.**.

Figure 2-18: Voltage & frequency response to loss of largest generator



It can be seen from **Error! Reference source not found.** that the system cannot withstand the loss of the largest generator on the network and the frequency drops below the 2% limit.

2.2.4.3 Additional 500 kW of solar PV generation with three diesel units in operation (B)

The generation dispatch portfolio in **Error! Reference source not found.** has been revised further and the DG4 and DG6 diesel generators operating at more even outputs while providing the same spinning reserve capacity. The generation mix of the case is shown in **Error! Reference source not found.** below.

Table 2-9: Updated generation mix on Kosrae for with additional PV generation

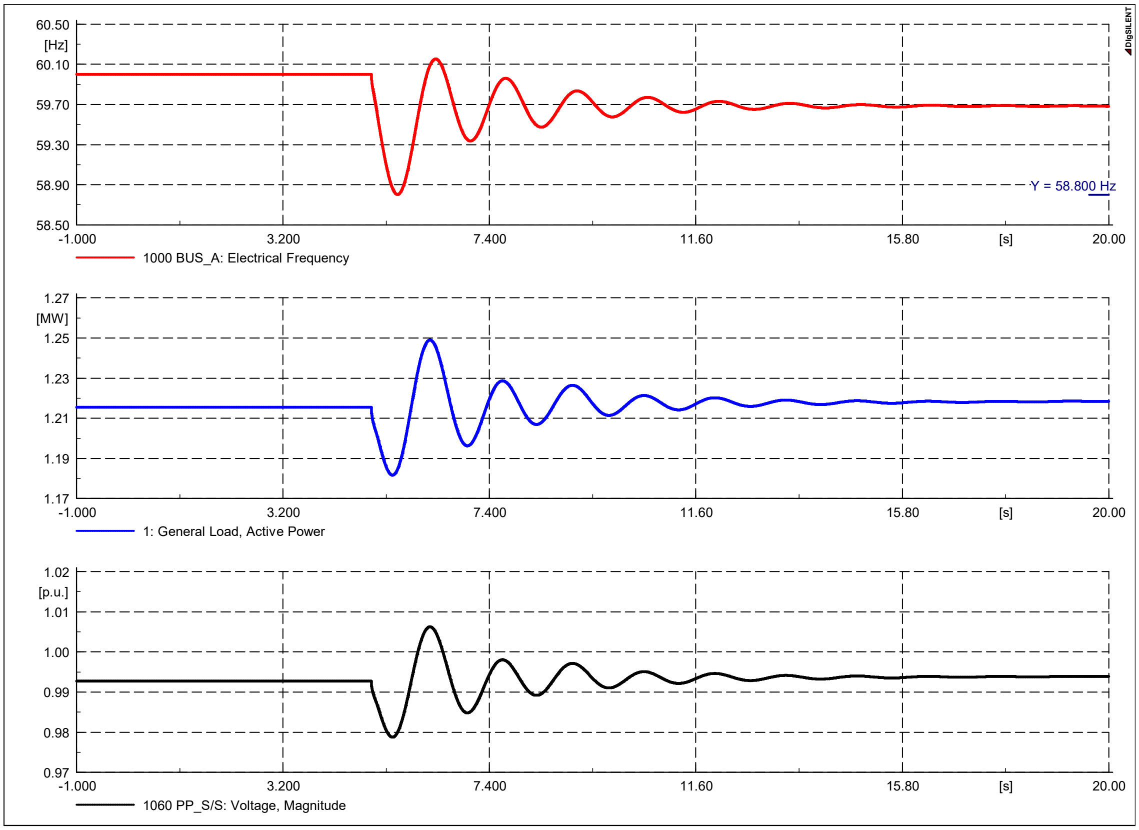
Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel	JICA DG1	2	0	150	450	21.6%
	JICA DG2	2	0	0	0	0.0%
	WB DG	3	0	0	0	0.0%
	DG 4	3	1	215.0	345.0	16.6%

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
	DG 6	3	1	210.9	1289.1	61.9%
	DG 8	3	1	0	0	0.0%
	Sub-total			**575.9**	**2084.1**	
	PV 1	1	1	150.0	0.0	0.0%
	PV 2	1	1	75.0	0.0	0.0%
Renewable	PV 3	1	1	34.1	0.0	0.0%
	New PV	1	1	375.0	0.0	0.0%
	Sub-total			**634.1**	**0.0**	
				1210	**2084.1**	**172.2%**

Loss of largest generator

With this revised generation dispatch portfolio, the response of the system frequency subject to the loss of the largest generator is improved and does not now exceed the 2% frequency deviation limit as shown in **Error! Reference source not found.**.

Figure 2-19: Voltage & frequency response to loss of largest generator



2.2.5 Summary of power system study results

The results presented in the previous sections show that under normal operating conditions i.e. maximum and minimum demand, the network has no thermal or voltage issues and it also has some headroom for future demand growth.

The fault level studies show that the maximum expected fault levels on this network are reasonable for the individual voltage levels however it is recommended that these are checked against the installed switchgear ratings to ensure safe operation.

The stability studies performed as part of this study highlighted some operational constraints of the existing system, as well as options for maintaining stability as the penetration of VRE is increased. The existing system remains stable however there are a number of instances of frequency deviations which exceed the acceptable limits. Changes to the generation dispatch, from two online diesel generators to three online generators, improves the system frequency responses to within the acceptable operational limits.

An additional 500 kW of solar PV connecting to the network has also been studied. Similar to the studies performed on the existing network, the dispatch of only two conventional generators is not sufficient to keep the system stable following a credible transient event. Inclusion of a third diesel generator in these studies also improved the response of the system. A summary of the stability study results is provided in **Error! Reference source not found.**.

Table 2-10: Summary of Stability Studies with increasing penetrations of VRE

Study	Existing System – Gen Dispatch 1 (2 x DG)	Existing System – Gen Dispatch 1 (3 x DG)	New PV– Gen Dispatch 1 (2 x DG)	New PV – Gen Dispatch 2 (3 x DG)	New PV – Gen Dispatch 3 (3 x DG revised)

Increase/Decrease PV response	OK	-	Oscillations	OK	-
Loss of largest demand feeder	OK	-	-	OK	
Fault at power station & subsequent loss of feeder	High frequency & rotor swing	OK	-	-	-
Loss of largest generator	Low frequency	OK	-	Low frequency	OK

With an additional 500 kW of solar PV generation, the system remains stable but it has a few issues with frequency deviation, as before. The generation dispatch of three diesel generators was refined to establish conditions whereby the system would respond to events without exceeding operational limits.

2.2.6 Recommendations for the present and future scenarios

The Kosrae network has a very small penetration of renewable generation, 345 kW, currently connected to the system. There are plans to connect around 500 kW of additional solar PV to the network in the coming year and this has been studied here to understand the ability of the network to accommodate this extra capacity. It is evident from the study results that the generation dispatch of the conventional diesel generators on the island is very important to the stability of the system. Upon completion of the two additional generators, and the World Bank funded generator, there will be an opportunity to improve and optimise the generation dispatch on the island among the six connected gensets, which should facilitate the connection of more VRE over and above the 500 kW planned solar PV.

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3 Task 2: Assessment of energy storage applications in power utilities

3.1 System studies on energy storage for frequency support

The prime objective of this task is to identify, assess and benchmark suitable storage solutions for frequency support, which would facilitate the deployment of variable renewable energy sources reviewed in task 1. The assessment and the benchmarking activity considers technical as well as economic and financial aspects of proposed solutions and configurations.

The analysis of storage requirements directly feeds from the dynamic modelling in Task 1 plus additional information required to determine the times of under / oversupply and uncertainty in forecasting renewable resources in real time to balance the power system.

The costs of wind and solar generation have decreased dramatically over the last decade, and the performance in terms of efficiency and reliability has steadily improved, making these viable sources of electricity, especially for grids that have in the past relied solely on diesel generators. If these renewable technologies could be integrated into an existing grid, consumers would generally experience an immediate benefit through a reduction in the amount of diesel consumed. However, the power produced by VRE is intermittent because the energy in the wind and solar radiation varies depending on the weather conditions. The operating frequency of electricity networks is a function of the balance of supply and demand, so grids must be able to control the frequency with varying supply from VRE.

The balancing of supply and demand has become one of the critical limiting factors in the increase of wind and solar generators for grids. Dynamic stability aspects of the network, such as voltage and frequency control, require fast response from generators, storage facilities and/or demand-response to match changes in demand. High-speed diesel engines can have the capability to respond to such changes within seconds. The Pacific Islands already show evidence that the fast response of high-speed diesel engines allows for very high instantaneous penetrations of renewable power in networks.

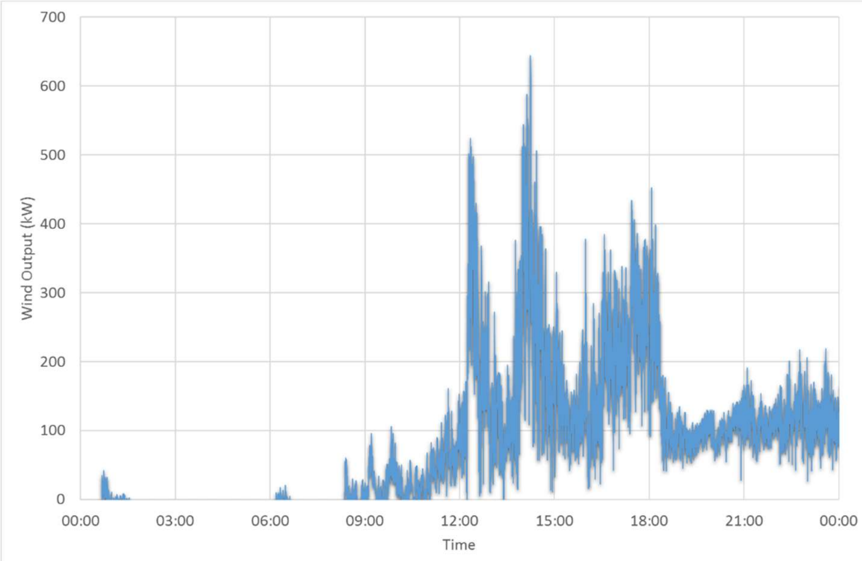
Fast frequency response within seconds or even fractions of a second can also be obtained from non-traditional sources including lithium-ion batteries, flywheels, and demand-response with thermal storage. Each of these sources can react to restore the balance of power but each has its limitations. Batteries respond very quickly but the relationship between the “number of cycles” and “depth of discharge” needs to be managed to optimise the useful life. Flywheels can respond very quickly but cannot sustain their response. Similarly, demand-response with thermal storage can be fast, but in a small grid is normally only available for short periods at a time. Owing to reductions in capital costs in recent years, lithium-ion batteries are becoming the most popular solution for small grids, but they need to be carefully selected, adequately sized and correctly installed.

The studies done here are to examine the current performance of the diesel generators and batteries in Kosrae and the technical limit with the economic impact for increasing solar power.

3.1.1 Wind and Solar intermittency

Continuous fluctuations in supply from VRE is normally termed “intermittency”. Wind variations are mainly due to fluctuations in the wind speed and direction, while solar PV mainly varies due to shadowing from clouds and changes in daylight hours through the course of the year. Figure 3-1 shows the intermittent output from a wind turbine measured every second over the course of a day at Aleipata, Samoa used as an example.

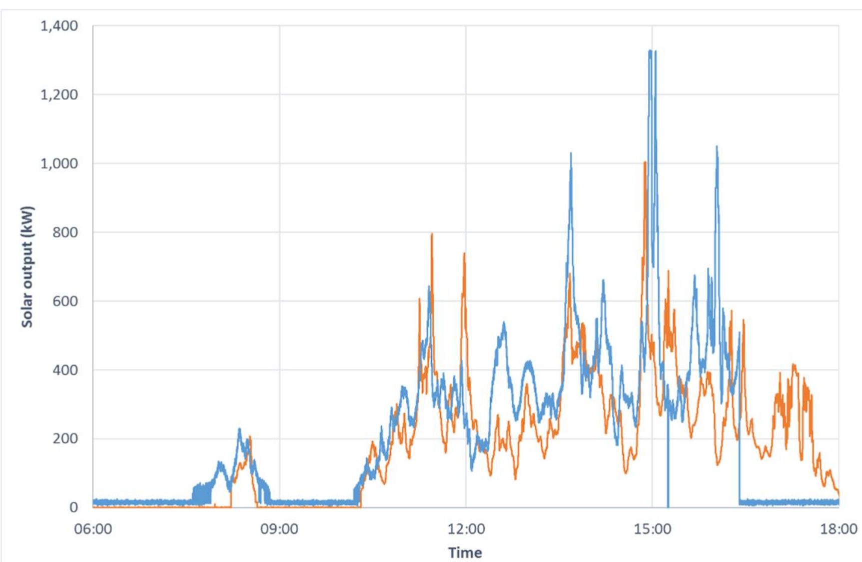
Figure 3-1. Wind power for recorded on 10 December 2016 at Aleipata



In a large grid with significant installed generation capacity, the grid-connected VRE plants can be located far away from each other to mitigate the effects of the variability of wind and solar irradiance, but for small grids, this is often not possible due to the small area that they serve. In addition, small grids may only have one wind turbine, so short-term variations in wind conditions have a more severe effect on the grid than in a gird where multiple turbines that are geographically spread.

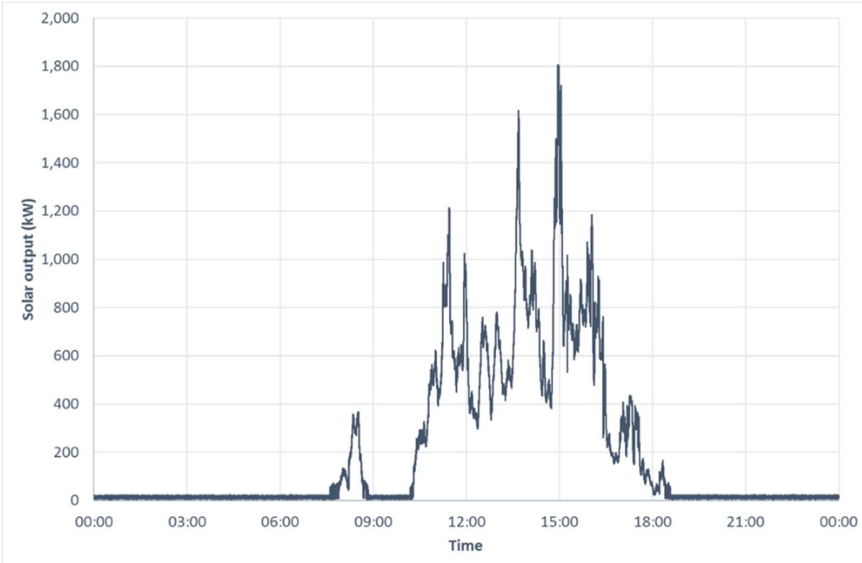
Figure 3-2 shows the individual outputs (measured at one second intervals) from two solar PV plants that are approximately 1 km apart.

Figure 3-2. Individual outputs from 2 Solar PV plants located 1 km apart



It seems that the two plants are exposed to the same cloud cover at the same time, but the combined output (Figure 3-3) shows there is not an exact correlation between the outputs of the two solar plants and the overall output is smoother than what would be obtained by doubling the output of the one farm.

Figure 3-3. Combined output of two solar plants 1 km apart (Source: Project confidential).



For fast frequency control, however, the plants do show a difference in response which reduces the overall ramp rate required to balance the system.

The models developed in Task 1 are used to determine the impact of disturbances (e.g. loss of a generation unit, distribution line) on frequency and voltage control. Task 1 identifies the maximum penetration of variable renewable resources for a selection of energy mix scenarios.

The studies conducted in Task 2 will determine suitable solutions for short-term dynamic stability. In particular, the analysis will determine the most suitable solution meeting minimum system stability requirements, while minimising system operating costs (e.g. storing long-term energy for later in the day/night).

A wide range of technologies has been considered including the use of batteries for frequency support and use of AGC (Automatic Generation Control). AGC provides techno-economic control where frequency control is not only based on the security of supply but also based on economic criteria.

These options have been modelled in the GDAT model and the results have been stated in the sections below.

This section focuses on the technologies for frequency support. Diesel generators have the capability to ramp up quickly and this could be in seconds or minutes depending on the nominal speed of the unit. The high-speed diesel units have the capability to ramp faster than the slow speed units.

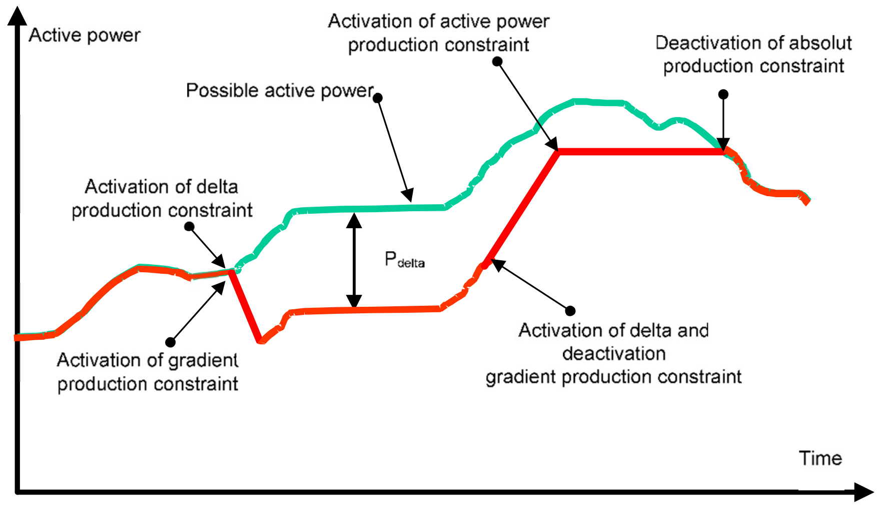
At present, a number of non-traditional sources are commercially available for frequency control/support and these sources include the use of Variable Renewable Energy (VRE) Sources, Fly-wheels, Synchronous Condensers and Batteries. More details of each of these resources and associated costs are as provided on the next sections.

3.1.2 VRE enhanced frequency control provision and calculation of costs

Enhanced frequency control provision can be provided by wind and solar farms in 3 ways.

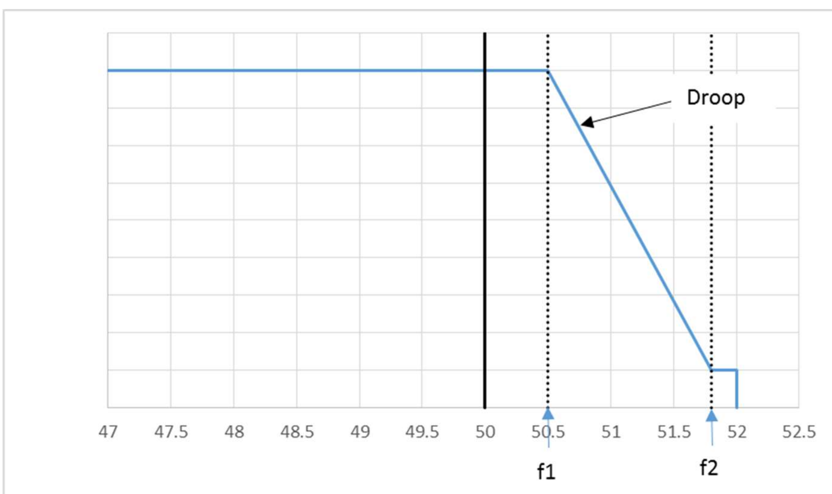
Option 1: The VRE plants are backed off from their full instantaneous maximum capacity, i.e. their outputs are limited. This is technically possible if the VRE plant control system can accept a set point from a central control system or a control philosophy is adopted in which the inverter is kept at an actual production, which is 5 - 10 percent below the maximum production (Figure 3-4) for primary frequency control purposes (Pdelta). The reduction in production of VRE plant will have to be replaced by diesel generation and so there would be a short run cost impact which would be in form of additional fuel costs. The average annual fixed costs (per kWh) for the VRE plant also increase as the generation is curtailed but there is no reduction in capital cost. Thus, if before implementing the scheme, the plant was generating at an average cost of $0.10 / kWh, after introduction of the scheme, the plant's average cost will be increased to $0.11 / kWh as the scheme reduces the generator output by 10%.

Figure 3-4 Reducing wind and solar power plant to be able to provide frequency control



Option 2: <u>VRE provides high-frequency response only</u> – The VRE plant will only respond by decreasing instantaneous power when the frequency is high. Figure 3-5 shows the typical response required in grid codes and programmed into most small VRE inverters. This response is designed for security only and so that the VRE will start reducing their output if the frequency is above 0.5 Hz the nominal value. The reduction is linear to frequency change and a full response is required when frequency is 1.5 Hz above the nominal value.

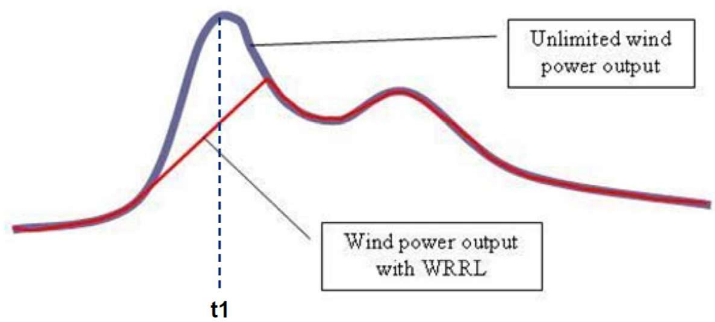
Figure 3-5 Typical VRE high frequency response only



Option 3: <u>VRE ramp rate is limited</u> – The VRE ramp rate is reduced to prevent frequency excursions. The up ramp on wind and solar can be easily limited in the inverter control logic. The ramp rate limitation is used worldwide to ensure wind and solar power plants do not ramp up too quickly. Ramp rates are generally not applied to domestic solar PV systems. This limitation prevents the wind / solar farm from producing full output and the amount of unused energy can be predicted. This essentially free energy that was lost and the cost can be calculated using the same method used Option 1 above. A down rate limiter can be provided to solar power plants using camera's to predict when clouds will cover the panels. The output is then reduced in a slower controlled ramp before the clouds actually cover the

panels. This logic has not yet been applied to wind farms as it is difficult to predict future wind gusts and lulls. Batteries can be used to control the VRE power plant ramp rate. The battery discharges power to sooth the down ramp and then charges to reduce the up ramp. This logic is applied to PV panels in Tonga. The use of batteries to control ramp rate on each power plant is suboptimal to using a central battery to controlling all the variation in all PV plants, simply based on the fact that all PV plants will not reduce at the same time and there is a netting effect.

Figure 3-6 Wind power output with wind ramp rate limit (WRRL)1



3.1.3 Fly Wheel and calculation of costs

The Flywheel principle is based on kinetic energy. The rotation speed contributes to Flywheels can spin within a range of 8,000 to 60,000 revolutions a minute. High-speed Flywheels are relatively small and possess a large energy capacity storage and because of the power electronics used the speed of the flywheel does not affect the electric frequency output of the installation. This result, in addition to the high energy capacity, also in a larger bandwidth the installation can deliver its energy.

Although at the moment there are many developments, the general specifications regarding 0.1 to 20 MW flywheels with a charge/ discharge time from 15 min to 1 hour.

Beacon Power has a demonstration plant in Hazle, PA, USA which consists of 200 flywheels each with a max power rating of 100 kW, 25 KWh, as shown in

Figure 3-7, charge and discharge under commercial operation from July 2014[2]. Lifetime output of 100 kW flywheel is estimated to be 4.375 MWh. Beacon flywheel is estimated to be capable of 100,000 to 175,000 cycles (20 times that of batteries). The cost of installation was US$ 52.415m or US$ 2,600 / kW installed.

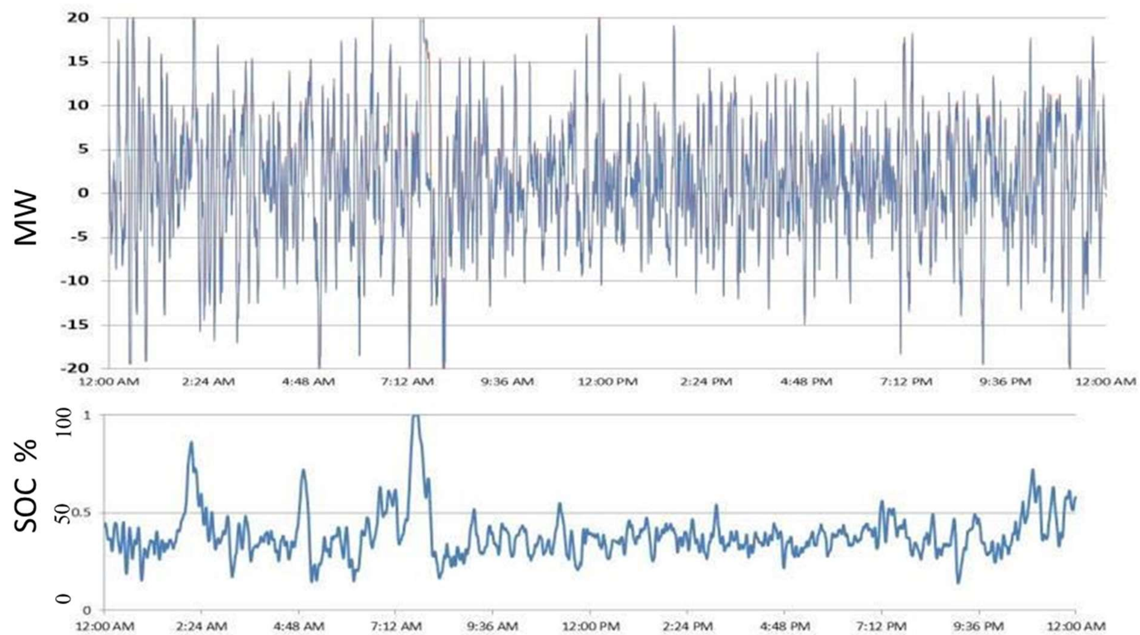
Various islands off the coast of Australia have installed flywheels as a form of energy storage to complement wind and solar PV systems. For example, the Flinders Island Hybrid Energy Hub features a single 900 kW wind turbine and 200 kW solar array. The storage systems include a 750 kW/300 kWh battery and an 850 kVA flywheel[3].

[1] AESO System Impact Studies, Phase 2 Assessing the impacts of increased wind power on AIES operations and mitigating measures, July 2006

[2] http://www.sandia.gov/ess/docs/pr_conferences/2014/Thursday/Session7/02_Areseneaux_Jim_20MW_Flywheel_Energy_Storage_Plant_140918.pdf

[3] Flicking the switch: (Hybrid) energy comes to Flinders Island. https://arena.gov.au/blog/flinders-island

Figure 3-7 Beacon Power installation in Hazle, PA, USA flywheel performance and state of charge (SOC)



3.1.4 Synchronous Condensers and calculation of costs

Synchronous condensers are synchronous electrical machines attached to the electricity grid. Hydro and pump storage units have compressors to empty the water from the water turbines. Hydro units have relative low speed with many poles to give the nominal frequency and the only friction is turbine blades running against air. The changing from Synchronous Condenser Operation (SCO) to generation on hydro units requires the air to be removed and input gates opened. This changeover is less than 2 minutes depending on the unit design. Gas turbines have clutches installed which disconnect the generator from the turbine. The clutch does require regular maintenance.

For Ireland, DNV KEMA notes that the conversion of non-profitable or deactivated power station is currently seen as the most cost-effective option for applying synchronous condensers[4]. Making an accurate cost calculation in general is not possible however, because depending on the existing installation the project will differ from unit to unit. Investments are relatively low when most of the existing infrastructure can be utilised (e.g. Step-up transformer, network infrastructures, buildings, auxiliary equipment and machinery, substations, etc.). In addition, the excitation and control and excitation itself may be changed, depending on the specific machine. The costs shown are therefore only a very rough indication.

General specifications:

- Energy consumption: 1 % – 4 % of the nominal power rating
- Inertia: approximately 1 sec.
- Response time: immediate

[4] System Service Provision - An independent view on the likely costs incurred by potential System Service Providers in delivering additional and enhanced System Services, DNV KEMA Energy & Sustainability

- Start-up time (if switched off): < 15 min.

The cost for converting the gas turbine to provide SCO operation is estimated to be US$100 / kW.

3.1.5 Batteries and calculation of costs

The most feasible current battery technologies are Sodium Sulphur (NaS) and Lithium-ion (Li-ion) [5]. The latter has a far smaller power to energy ratio and therefore can be used for frequency response. Li-ion is thus a cheaper alternative as opposed to NaS regarding frequency response services. For peak shaving, however, and ultimately energy storage, NaS batteries are considered to be the better technology at the moment, having a power to energy ratio of approximately 1:8.

The proposed batteries have the following general characteristics:

- Energy efficiency: 95 % (Li-ion); 90 % (NaS)
- Ramp-up time: < 1 electrical frequency cycle period
- Load time: 2 min – 3 hours (Li-ion); 1 hour – 8 hours (NaS)
- Life cycle: > 4,500 load cycles

The capital costs for Li-ion batteries is US$750 / kWh[6] and for NaS US$2,200 /kWh[7]. The cost of inverter is estimated to be US$1,000 / kW[8].

Bloomberg estimates Li Ion batteries to be under US$ 200 / kWh[9] and a recent report from USTDA has batteries at US$375 / kWh and inverters at US$300 / kWh [10]

The capital cost for Samoa's current batteries of 8 MW and 13.6 MWh is $ 8.8 m for inverters and batteries.

The estimated capital cost for batteries for Kosrae of 1.25 MW with 5 MWh is $ 0.625 m for inverters and $1.875 m for batteries a total of $2.5m. For a ten year life time of batteries and inverter, with a 2% interest on debt and fixed O&M of US$7.5 / kW[11], the annualised cost is $287,691 as shown by annuity calculator below:

Similarly, for a 2.5 MW / 13 MWh battery the annualised costs is $ 700,625.

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[5] System Service Provision - An independent view on the likely costs incurred by potential System Service Providers in delivering additional and enhanced System Services, DNV KEMA Energy & Sustainability
[6] Energy Master Plans for the Federated States of Micronesia, Castalia, 2018
[7] System Service Provision - An independent view on the likely costs incurred by potential System Service Providers in delivering additional and enhanced System Services, DNV KEMA Energy & Sustainability
[8] Energy Master Plans for the Federated States of Micronesia, Castalia, 2018
[9] https://www.bloomberg.com/news/articles/2018-03-08/the-battery-will-kill-fossil-fuels-it-s-only-a-matter-of-time
[10] US TRADE AND DEVELOPMENT AGENCY, South Africa Energy Storage, Technology and Market Assessment, March 2017
[11] US TRADE AND DEVELOPMENT AGENCY, South Africa Energy Storage, Technology and Market Assessment, March 2017

Annuity Payout Calculator

Installed Capacity	1250	kW
	1.25	MW
Capital Expenditure	$ 2,500,000	USD
	2.5	m USD
Fixed Opex	$ 9,375	USD/year
Variable Opex	$ -	USD/hour
Energy Availability	99%	%
	-	USD/year
Life of the Plant	10	Years
Interest on Debt	2%	%
Interest on Equity	0%	%
Debt to Equity Ratio	1	%
WACC	2.00%	

Annual Payments		
Capital Payment	$ 278,316	USD
Fixed Opex	$ 9,375	USD
Variable Opex	$ -	USD
Total	$ 287,691	USD

Inputs in yellow

Annuity Payout Calculator

Installed Capacity	2500	kW
	2.5	MW
Capital Expenditure	$ 6,125,000	USD
	6.125	m USD
Fixed Opex	$ 18,750	USD/year
Variable Opex	$ -	USD/hour
Energy Availability	99%	%
	-	USD/year
Life of the Plant	10	Years
Interest on Debt	2%	%
Interest on Equity	0%	%
Debt to Equity Ratio	1	%
WACC	2.00%	

Annual Payments		
Capital Payment	$ 681,875	USD
Fixed Opex	$ 18,750	USD
Variable Opex	$ -	USD
Total	$ 700,625	USD

Inputs in yellow

3.2 Generation Dispatch Analysis Tool (GDAT)

3.2.1 Introduction to GDAT

The Generation Dispatch Analysis Tool (GDAT) is a product in MATLAB© & Simulink©.

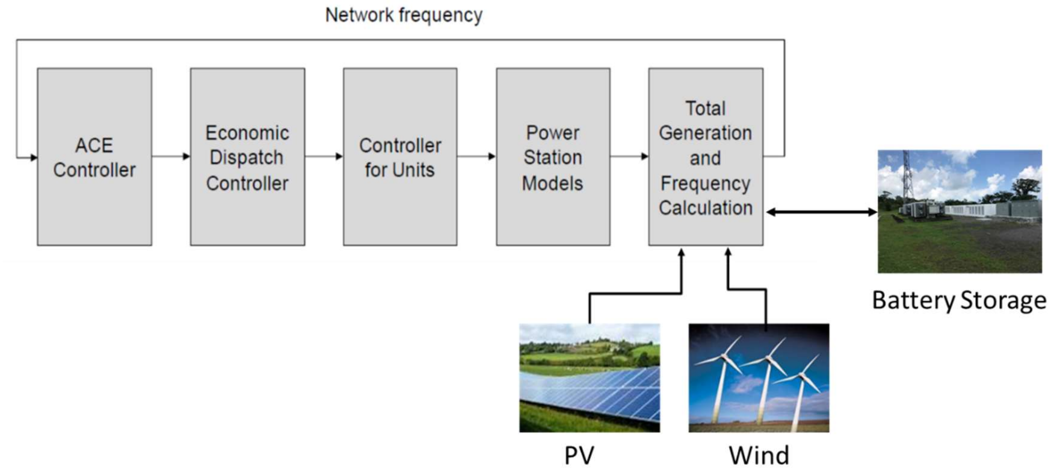
The Generation Dispatch Analysis Tool is used for four main purposes

1. Determining the benefits for controlling network frequency using primary (governor) and secondary (AGC) control options;
2. Analyse impact of non dispatchable renewable energy on frequency control;
3. Analyse the benefits of storage on frequency control;
4. Tuning Automatic Generation Controller;
5. System Operator controller dispatch performance analysis; and
6. System Operator dispatch audit.

The Generation Dispatch Analysis Tool was developed in 1998 for the optimisation of Automatic Generation Control settings for improved secondary frequency reserve, economic dispatch and interchange power control. From 2007 the tool has been refined for intermittent resources management and used for minute to minute wind farm integration studies in Mauritius and small island systems. The Generation Dispatch Analysis Tool has also been used for system operation studies and system operator audits in South Africa, Tanzania, Thailand and Abu Dhabi. Each of these systems are also analysing the impact of future renewable energy plants on minute to minute dispatch, as shown in Figure 3-8. South Africa has increased the wind and solar renewable penetration to nearly 10% of peak demand and South Africa for example is using the tool to analyse the impact of solar and wind projects on secondary frequency reserve. South Africa extensively uses pump storage for energy storage and the running of these power plants is required for secondary control when there is significant wind and solar power plants online. The power plants are required for energy storage but are more important for system security during the day to cope with rapid ramping required during the shoulder periods when solar is dropping off and demand is increasing.

The GDAT model for Kosrae also includes battery storage systems for system security studies and for energy storage analysis.

Figure 3-8 Generation Dispatch Analysis Tool with wind and solar inputs added



The studies under taken in GDAT use original recorded generation, demand and frequency data from SCADA. The technical parameters for power plants such as ramp rates, network dynamics and frequency control capability are modelled. Additional constraints including spinning reserve, storage capability are also included. For Kosrae, the studies are to determine the appropriate level of automatic control to ensure frequency control with increasing VRE with and without using batteries for frequency control and storage.

The user can select the options for the study, including which units to use for frequency control, controller settings, reserve levels, demand and power plant technical parameters.

GDAT calculates the resultant frequency with the various configurations of controller settings and also calculates the cost of dispatch from the cost curves entered into the model. The model is designed to commits and de-commits diesel units to ensure sufficient spinning reserve level without committing too many units.

The results from the studies therefore analyse the techno-economic benefits of the options selected to study. The technical limits for various control strategies and levels of VRE can be determined as well as the economic impact of each option studied.

3.2.2 Input data to GDAT for Kosrae studies

The models developed for Kosrae are based on hourly data records received for the period ending 31 January 2018. The real time PV data was obtained from recorded one second data from Tonga where we have records of a 1 and 1.2 MW PV plant which are about a kilometre apart. For the Solar PV is then scaled for conditions in Kosrae.

The demand profile is taken from data provided by Kosrae and the weekday profile is shown:

Figure 3-9 Typical weekday profile for Kosrae

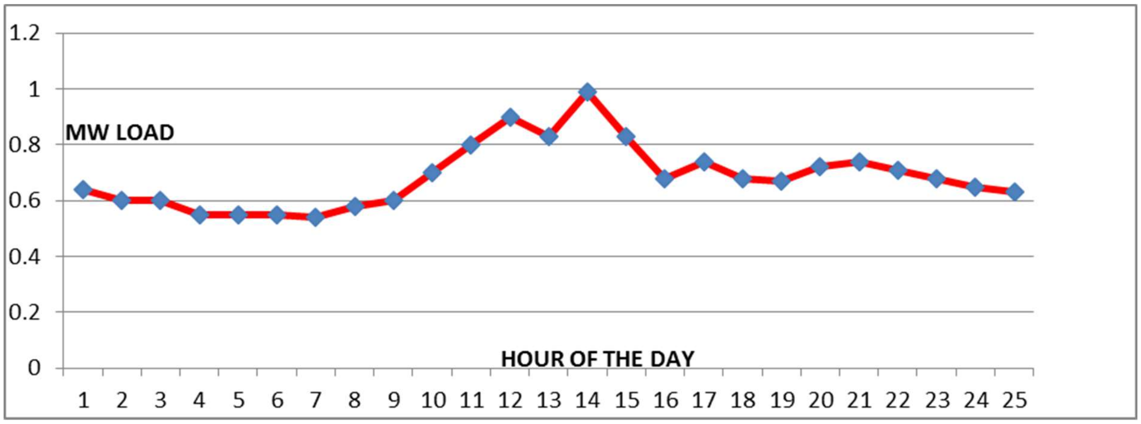
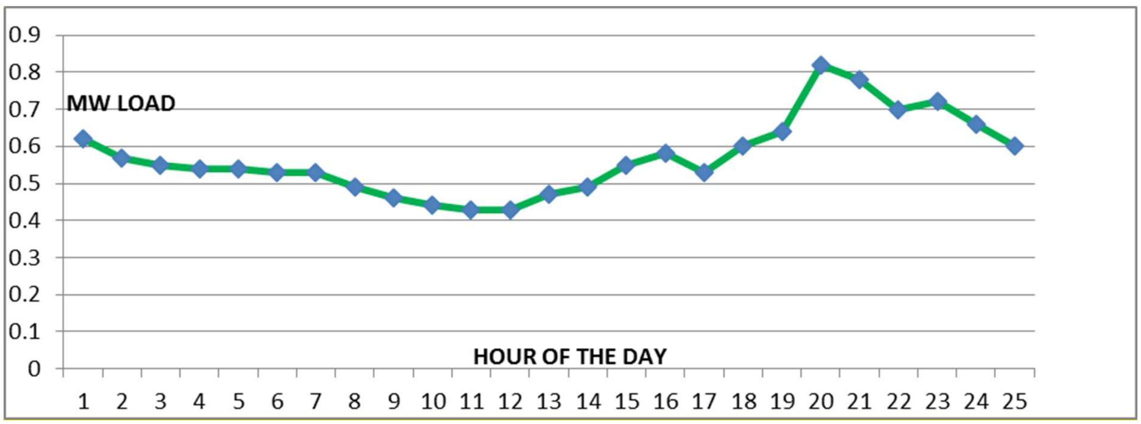


Figure 3-10 Typical weekend profile for Kosrae



The names in the model are made generic to reflect that this is not the actual output of any specific unit as it will be seen that the wind and solar outputs can be scaled to reflect an increase/decrease in wind or solar capacity.

Table 3-1: Generation and GDAT name for Generation Plants

Name	Capacity (kW)	Type	GDAT name
Tofol DG6	1100	Cat Diesel	D1
Tofol DG8	800	Cat Diesel	D2
Tofol DG4	450	Cat Diesel	D3
New PS DG1 (JICA)	600	Diesel	D4
New PS DG2 (JICA)	600	Diesel	D5
KUC Site	200	PV	PV1
Governor's building	100	PV	PV2

A Wind Power Plant is added to the model "W1" but not utilised for these studies as it is understood there is no immediate plan for a wind farm.

Generation parameters used for inputs into the model for Diesel, PV Wind and Battery power plants are shown in Table 3-2.

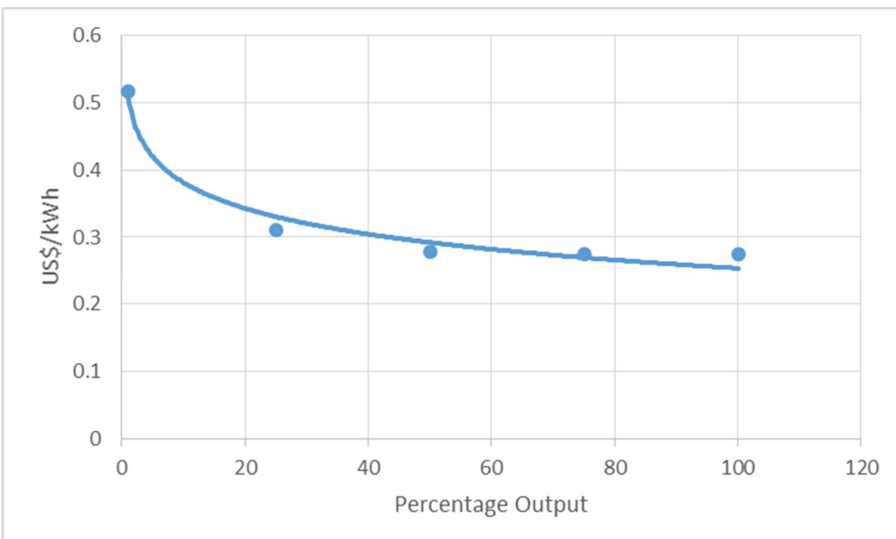
Table 3-2: Kosrae generation parameters

Overview Batch

Unit Name	D1	D2	D3	D4	D5	W1	PV1	PV2	B1
Model type	Diesel	Diesel	Diesel	Diesel	Diesel	Wind	Solar	Solar	Battery
MCR	1.1000	0.8000	0.4500	0.6000	0.6000	1.0000e-03	0.2000	0.1000	0.5000
Unit Inertia	0.4500	0.4500	0.4500	0.4500	0.4500	0	0	0	0
Ramp Rate	1.1000	0.8000	0.4500	0.6000	0.6000	60	30	30	10
Maximum Generation	1.1000	0.8000	0.4500	0.6000	0.6000	0.8250	0.2000	0.1000	0.5000
Minimum Generation	0.2200	0.1600	0.0900	0.1200	0.1200	0	0	0	0
Spinning Capability	1.1000	0.8000	0.4500	0.6000	0.6000	0.8250	0.2000	0.1000	0.5000
Nonspinning Capability	1.1000	0.8000	0.4500	0.6000	0.6000	0.8250	0.2000	0.1000	0.5000
AGC On	☑	☑	☑	☑	☑	☑	☑	☑	☐
Model Name	DEGOV1	DEGOV1	DEGOV1	DEGOV1	DEGOV1	RecordedData	RecordedData	RecordedData	Battery
Frequency deadband	1.0000e-03	1.0000e-03	1.0000e-03	1.0000e-03	1.0000e-03	1	1	1	1
Lower frequency limit	-1	-1	-1	-1	-1	-1	-1	-1	-1
Upper frequency limit	1	1	1	1	1	0	0	0	1
Droop (R)	0.0800	0.0800	0.0800	0.0800	0.0800	0.0400	0.0400	0.0400	0.0400

The fuel cost curve that plots power against US$/kWh for CAT units, as shown in Figure 3-11 below, is based on a typical similar sized diesel generator's performance with average 0.275 litre per kWh[12] assumed around 70% for each generator. The cost curve was drawn for a fuel cost of US$ 0.79 per litre[13]. The minimum generation is set to be at 20% of the rated capacity as a typical minimum value.

Figure 3-11 CAT diesel units cost curve



The key parameters for the AGC controller are shown in Figure 3-12 below, for the purpose of the analysis, the demand is assumed to be the same as generation. The demand was calculated by summing the generation. The other parameters selected are described in the appendix. For Kosrae the simulation is run every second for a day.

[12] Preparatory survey report on the project for power sector improvement for the state of Kosrae in federated states of Micronesia, JICA, April 2016

[13] Energy Master Plans for the Federated States of Micronesia Final Report (Appendices), April 2018

Figure 3-12 GDAT controller parameters

Sample Time	1
Frequency error gain	0.019
Controller deadband	0.001
Controller proportional gain	0.1
Controller integral gain	0
Controller derivative gain	0
agcControllerType	1

The solar PV power output dates chosen were 28 March 2016 from Tonga, as shown in Figure 3-13, which was a relatively sunny day with significant periods of low PV output followed full output from the PV plants and 02 October 2016, as shown in Figure 3-14, which was a typical partially cloudy day in the pacific islands with constant drops in PV power.

Figure 3-13 Recorded 'normalised' one second PV output for 28 March 2016

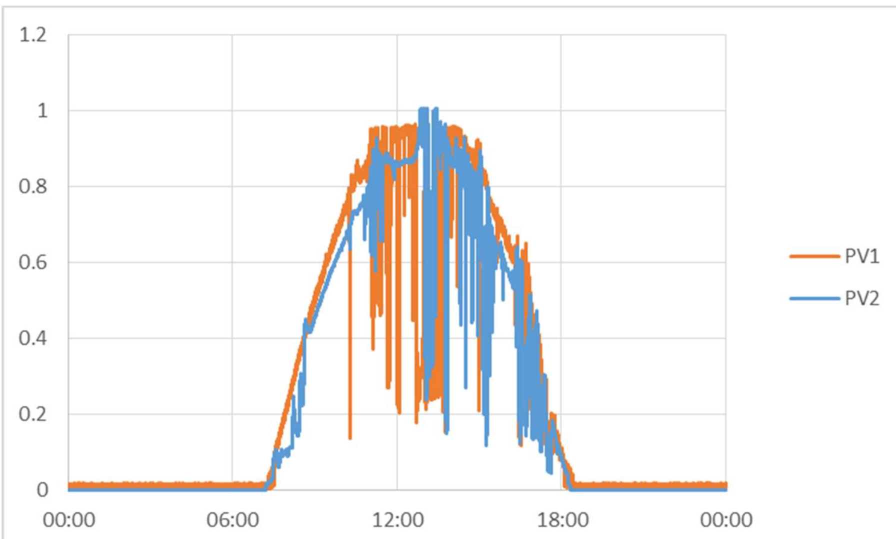
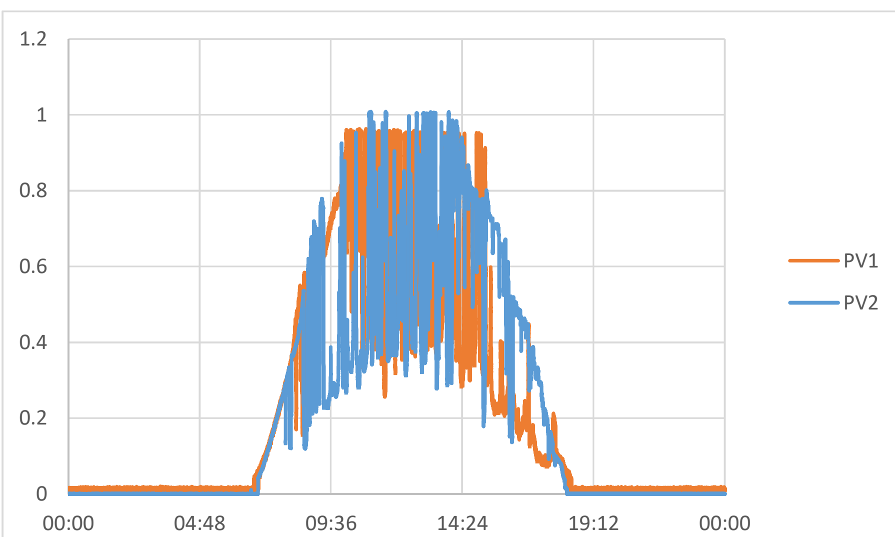


Figure 3-14 Recorded 'normalised' one second PV output for 02 October 2016



3.3 Results of Generation Dispatch Analysis Tool (GDAT)

The following analysis was carried out on the GDAT tool:

1. The simulations performed: Base case – re-run/simulated the day in question with the same conditions to ensure accuracy of the model developed.
2. Increased spinning reserve to understand the techno economic impacts of increasing spinning reserve
3. Add batteries on primary frequency control only and then on AGC
4. Increased PV to reduce diesel to minimum during the day and maximise usage of batteries on primary control and then on AGC control

The summary of the simulations with various changes to input parameters is shown in Table 3-3

Table 3-3 Simulations performed

					Controller status	
Case Number	**Simulation date**	VRE Installed (MW)	% peak	**PV data date**	**Solar PV**	**Battery**
Base 1	Weekend	0.3	12%	02/10/16	AGC	off
1	Weekend	1	40%	02/10/16	AGC	off
2	Weekend	1	40%	02/10/16	AGC	0.5 MW on Gov
3	Weekend	2.3	92%	02/10/16	AGC	0.5 MW on Gov
4	Weekend	2.3	92%	02/10/16	AGC	1.25 MW / 5 MWh on Gov & AGC
5	Weekend	2.3	92%	02/10/16	AGC	1.25 MW / 5 MWh on Gov & AGC – diesel off
6	Weekend	4.3	172%	02/10/16	AGC	2.5 MW / 13 MWh on Gov & AGC – diesel off
Base 2	Weekend	0.3	12%	28/03/16	AGC	off
7	Weekend	1	40%	28/03/16	AGC	off
8	Weekend	1	40%	28/03/16	AGC	0.5 MW on Gov
9	Weekend	2.3	92%	28/03/16	AGC	0.5 MW on Gov
10	Weekend	2.3	92%	28/03/16	AGC	1.25 MW / 5 MWh on Gov & AGC
11	Weekend	2.3	92%	28/03/16	AGC	1.25 MW / 5 MWh on Gov & AGC – diesel off
12	Weekend	4.3	172%	28/03/16	AGC	2.5 MW / 13 MWh on Gov & AGC – diesel off
Base 3	Weekday	0.3	12%	02/10/16	AGC	off
13	Weekday	1	40%	02/10/16	AGC	off
14	Weekday	1	40%	02/10/16	AGC	0.5 MW on Gov
15	Weekday	2.3	92%	02/10/16	AGC	0.5 MW on Gov
16	Weekday	2.3	92%	02/10/16	AGC	1.25 MW / 5 MWh on Gov & AGC
17	Weekday	2.3	92%	02/10/16	AGC	1.25 MW / 5 MWh on Gov & AGC – diesel off
18	Weekday	4.3	172%	02/10/16	AGC	2.5 MW / 13 MWh on Gov & AGC – diesel off
Base 4	Weekday	0.3	12%	28/03/16	AGC	off
19	Weekday	1	40%	28/03/16	AGC	off
20	Weekday	1	40%	28/03/16	AGC	0.5 MW on Gov
21	Weekday	2.3	92%	28/03/16	AGC	0.5 MW on Gov

22	Weekday	2.3	92%	28/03/16	AGC	1.25 MW / 5 MWh on Gov & AGC
23	Weekday	2.3	92%	28/03/16	AGC	1.25 MW / 5 MWh on Gov & AGC – diesel off
24	Weekday	4.3	172%	28/03/16	AGC	2.5 MW / 13 MWh on Gov & AGC – diesel off

3.3.1 Base Case 1 & Simulation cases 1 – 6 Weekend with PV from 02 October 2016

Base Case 1: Weekend - Simulation of original PV with Tonga PV data from 02 October 2016

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data. Figure 3-15 shows the simulation of generation unit outputs for a typical weekend day, with PV from Tonga 02 October 2016. This is the base case for these simulations where we can compare techno-economic impact of cases 1 to 6. The simulated frequency, as shown in Figure 3-16, shows the expected frequency variations without any frequency deviations from normal second to second changes in load.

Figure 3-15 Simulated generation on weekend with current installed PV

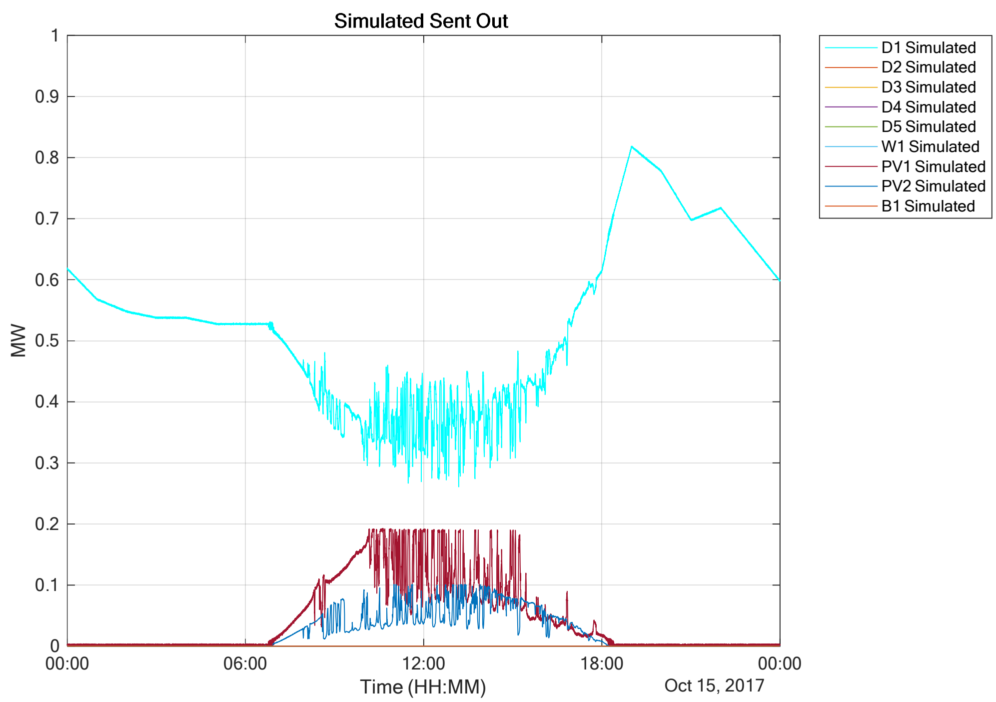
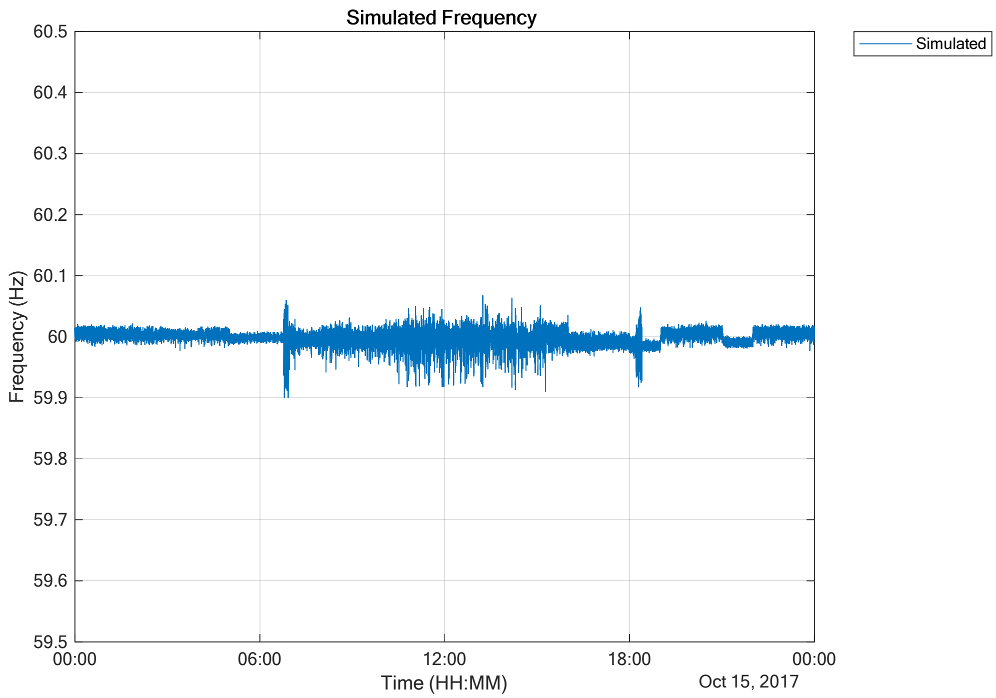


Figure 3-16 Simulated frequency on weekend with current installed PV



Case 1: Weekend - 1 MW of PV with Tonga PV data from 02 October 2016

For Case 1 the PV power plants are set to 0.5 MW each giving a total PV of 1 MW, Diesel units D1 is the only unit on to perform the frequency control, as shown in Figure 3-17. The frequency is acceptable but there are frequency excursions where the Diesel Power plant is starting to struggle to control the frequency with high PV penetration and variation, as shown in Figure 3-18. When diesel unit is at minimum generation the PV is backed off to control frequency. The diesel unit is at minimum generation from 09:30 to 17:00 and PV power is curtailed by 36.0 %

Figure 3-17 Simulated generation on weekend with 1 MW PV

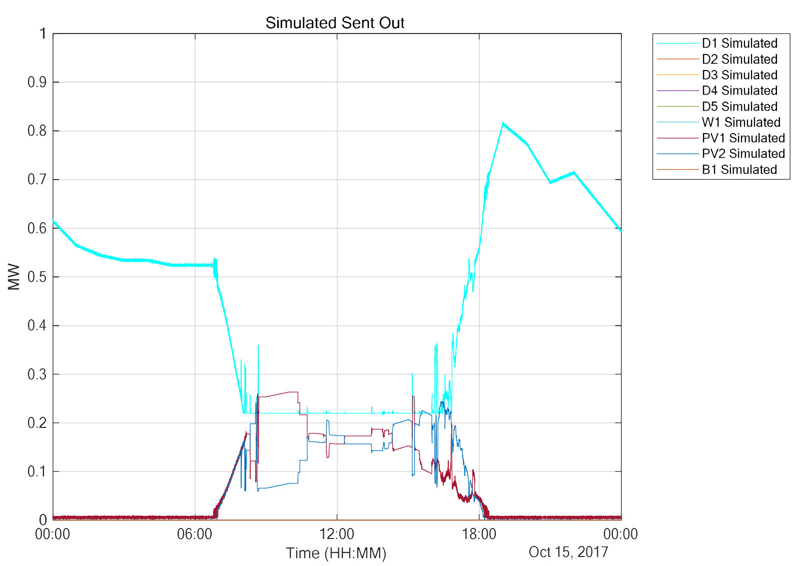
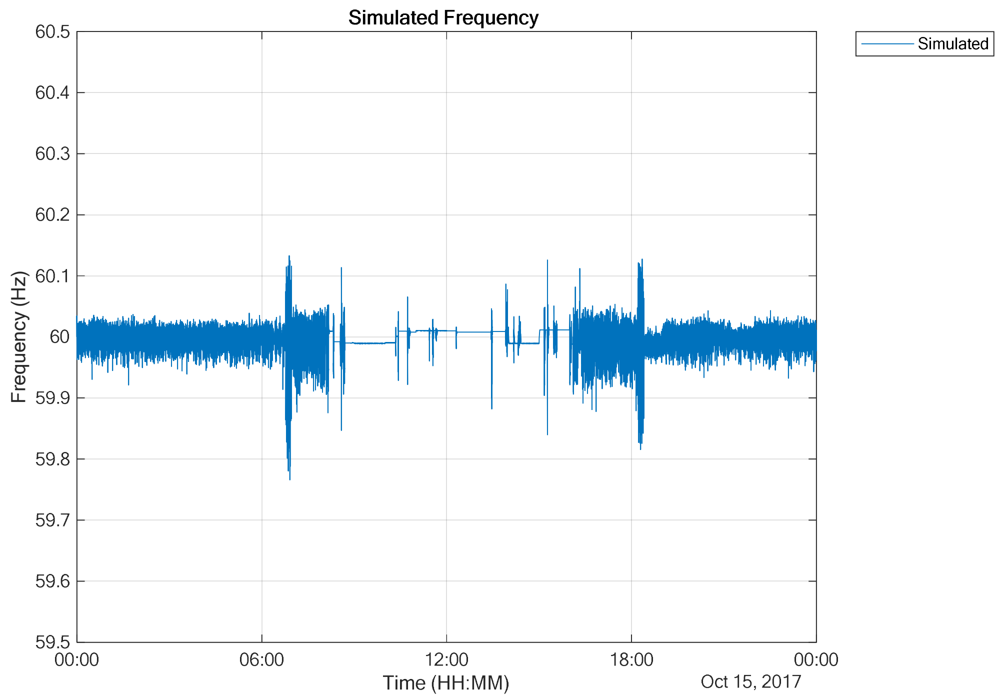


Figure 3-18 Simulated frequency on weekend with 1 MW PV



Case 2: Weekend - 1 MW of PV and 0.5 MW / 0.5 MWh battery on primary frequency control

Batteries can be used for primary frequency control only and thus only respond to frequency variations. For these simulations, the battery control parameters are in Figure 3-19. The deadband is set to 0.05 Hz and thus the battery will respond to frequency variations outside of this range and droop is set to 0.1 %, thus a 0.1% change in frequency will result in 100% change in power. Thus the battery will go from zero output to full output if the frequency drops from 59.95 to 59.9 Hz and similarly will go to from 0 to full charge with a frequency variation from 60.05 to 60.1 Hz.

A 0.5 MW / 0.5 MWh battery costs US$ 52.455 per annum or US$ 143.7 per day.

Figure 3-19 Battery parameters when on primary frequency control only

Misc	
Unit Name	B1
Model type	Battery
MCR	0.5
Unit Inertia	0
Ramp Rate	200
Maximum Generation	0.5
Minimum Generation	-0.5
Spinning Capability	0.5
Nonspinning Capability	0
AGC On	False
Model Name	Battery
Frequency deadband	0.001
Lower frequency limit	-1
Upper frequency limit	1
Droop (R)	0.001

The simulated frequency improves when 0.5 MW battery is on primary frequency control only, as shown in Figure 3-20. There are a few occasions during the period when the battery is utilised and the response is enough to prevent frequency excursion, as shown in Figure 3-21. The diesel fuel costs remain the same at $3,111 as for case 1 showing the battery is just performing primary frequency control and the battery on discharges a few percent, as shown in Figure 3-22. The net cost of US$ 25 is calculated for the simulation day including the battery costs.

Figure 3-20 Simulated frequency for weekend with 1 MW of PV and 0.5 MW battery on primary frequency control

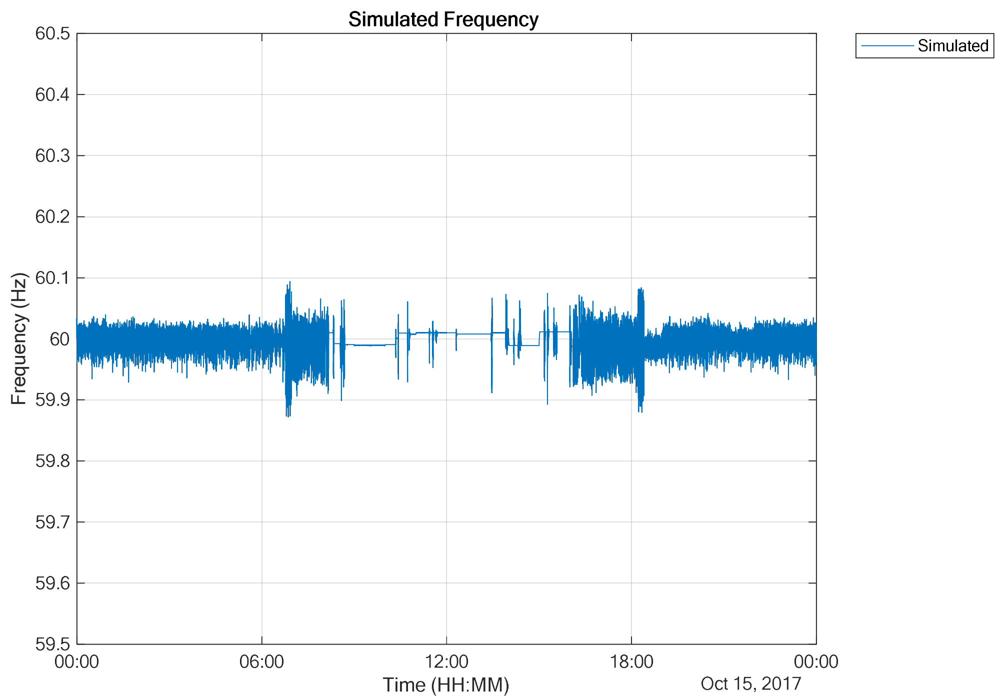


Figure 3-21 Simulated battery power for weekend with 1 MW of PV and 0.5 MW battery on primary frequency control

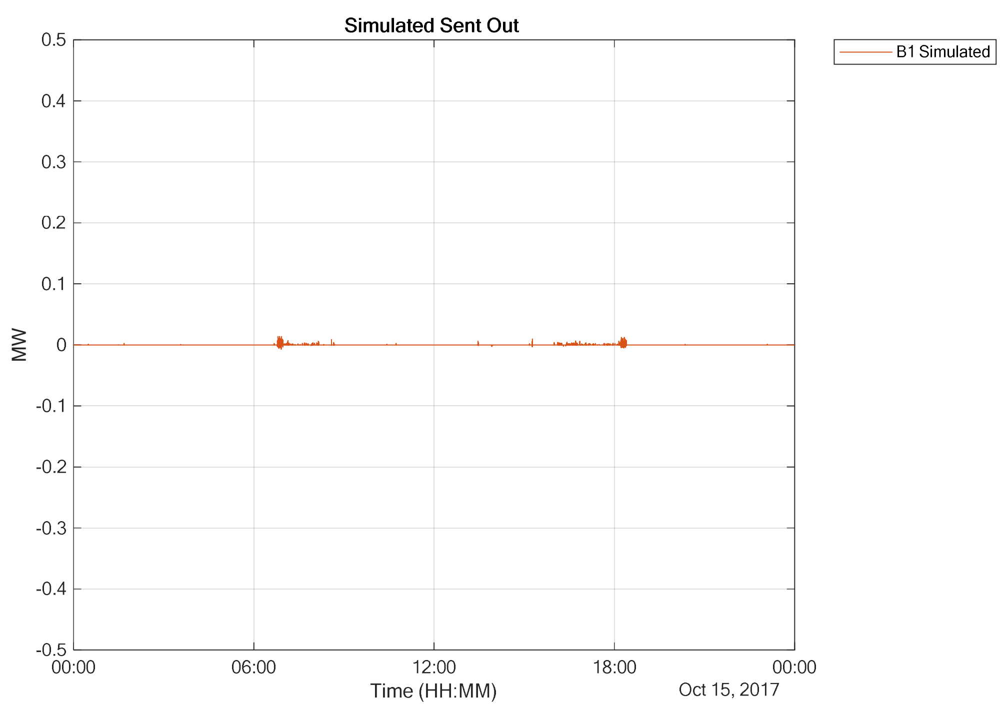
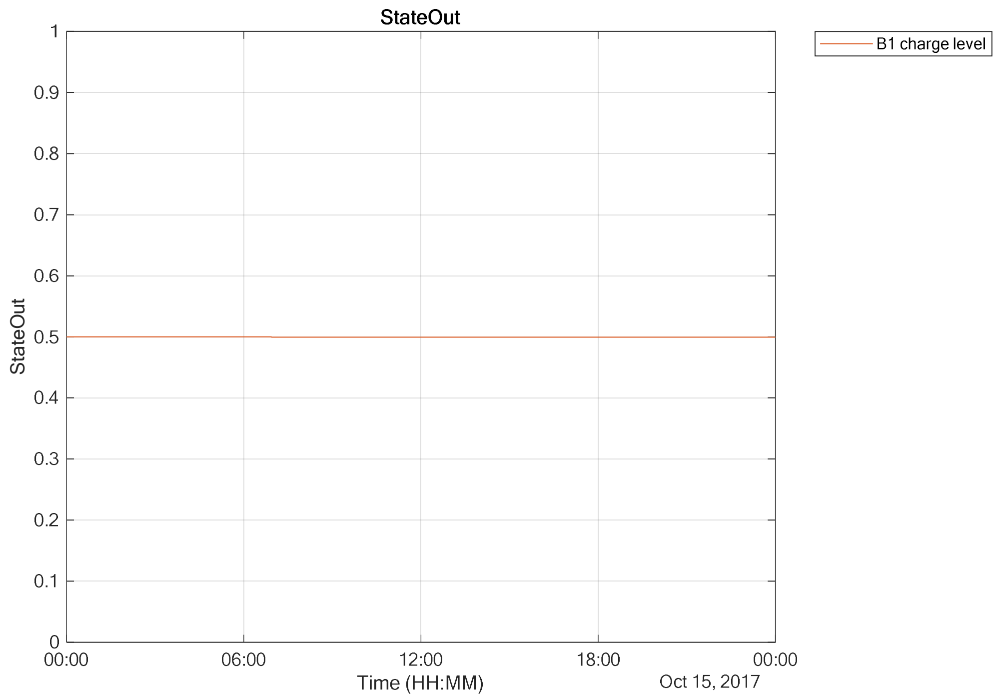


Figure 3-22 Simulated battery charge for weekend with 1 MW of PV and 0.5 MW battery on primary frequency control



<u>Case 3: Weekend – 2.3 MW of PV and 0.5 MW / 0.5 MWh battery on primary frequency control</u>

For Case 3 the PV power plants are set to 1.15 MW each giving a total PV of 2.3 MW, Diesel unit 1 provides the secondary control under AGC to perform the control assisted by a 0.5 MW battery on primary frequency control, as shown in Figure 3-23. The frequency is acceptable control well within the range of 59.5 to 60.5 Hz, as shown in Figure 3-24. The battery full range is not fully utilised to control the frequency and so battery size is fine for frequency control for this simulation case, as shown in Figure 3-25.

Only 50.4% of the available energy from the 2.3 MW of PV is used resulting but still results in a fuel saving of US$1,147 but a net loss of US$ 587 for the simulation day.

Figure 3-23 Simulated generation for weekend with 2.3 MW of PV and 0.5 MW battery on primary frequency control

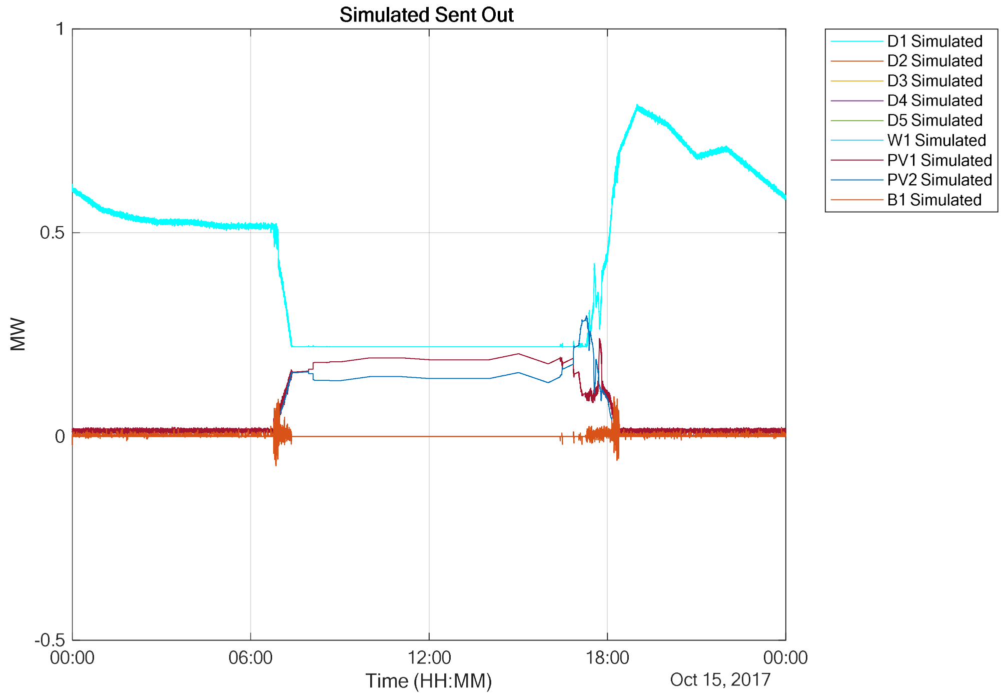


Figure 3-24 Simulated frequency for weekend with 2.3 MW of PV and 0.5 MW battery on primary frequency control

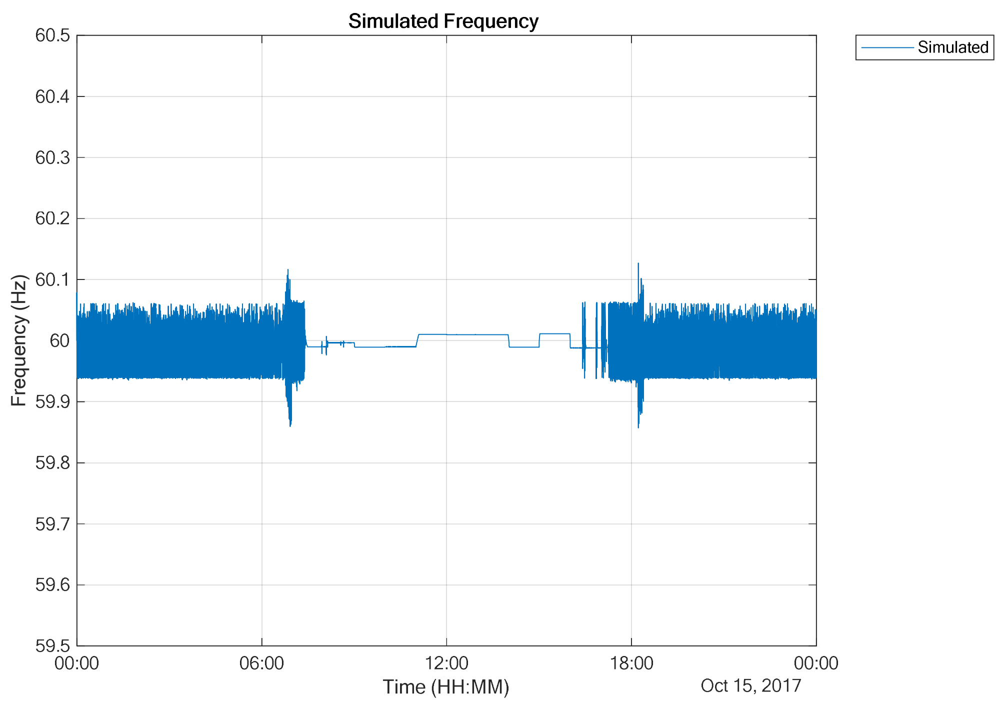
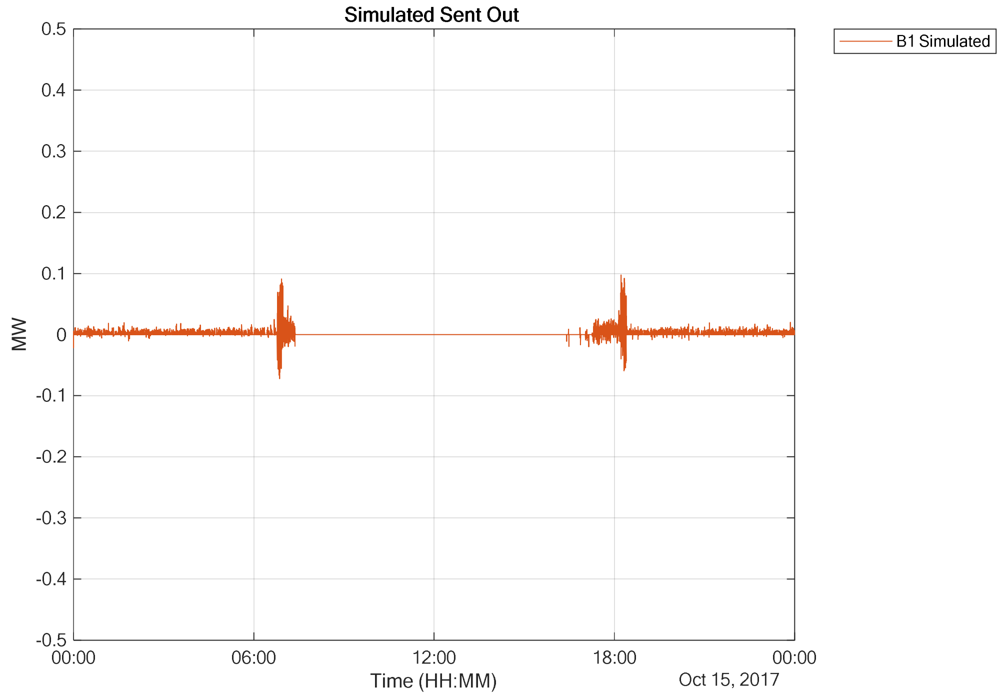


Figure 3-25 Simulated battery output for weekend with 2.3 MW of PV and 0.5 MW battery on primary frequency control



Case 4: Weekend – 2.3 MW of PV and 1.25 MW / 5 MWh battery on AGC

Case 4 is simulating the same as Case 3 but now with assistance of 1.25 MW / 5 MWh battery on AGC as proposed by FSM Energy Master Plan Study, April 2018. The batteries also provide primary frequency control as for the simulations above. The philosophy for the batteries under AGC control is:

1. Starting batteries with a charge of 20% - assuming batteries have been utilised the previous evening – update to actual midnight value to give a typical continuous day's profile (need to run simulation twice)
2. Battery is discharged whenever possible to displace diesel. Battery provide power at half their potential – keeping the remaining half available for primary frequency control
3. Battery is charged using any excess PV available – when PV exceeds demand minus diesel generation minimum demand. Battery is charge to 95% keeping some capacity for primary frequency control high frequency response after charging.
4. The discharge level is limited by the AGC controller to 50% of the battery size to ensure frequency is controlled at the same time as optimising the energy available – essentially system security before economics

Figure 3-26 shows the when battery simulated outputs when put on primary frequency control and AGC, the batteries use the excess PV to charge the battery almost full charge level, as shown in Figure 3-27, by 12:00. The batteries then discharge instead of using diesel generation from 17:00 Hrs until charge level is 20% which is around 03:00 the next day. The simulated diesel generator 1 output is at minimum generation for most of the period from 07:30 Hrs to 03:00 Hrs the next day, as shown in Figure 3-28.

The fuel costs for Case 4 is $ 2,011 compared to $ 2,989 for Case 3. This reduction is due to an increase PV output of 3.8 MWh which is used to charge the batteries and is later discharged instead of using diesel power. Using the batteries on AGC in this simulation case saves an extra $978 on fuel costs. The hourly cost for the batteries is calculated as $ 788 and this case has a net loss of $ 253 for the simulation day.

Figure 3-26 Simulated battery output for weekend when 1.25 MW / 5 MWh battery provides both primary frequency control and AGC with 2.3 MW of PV.

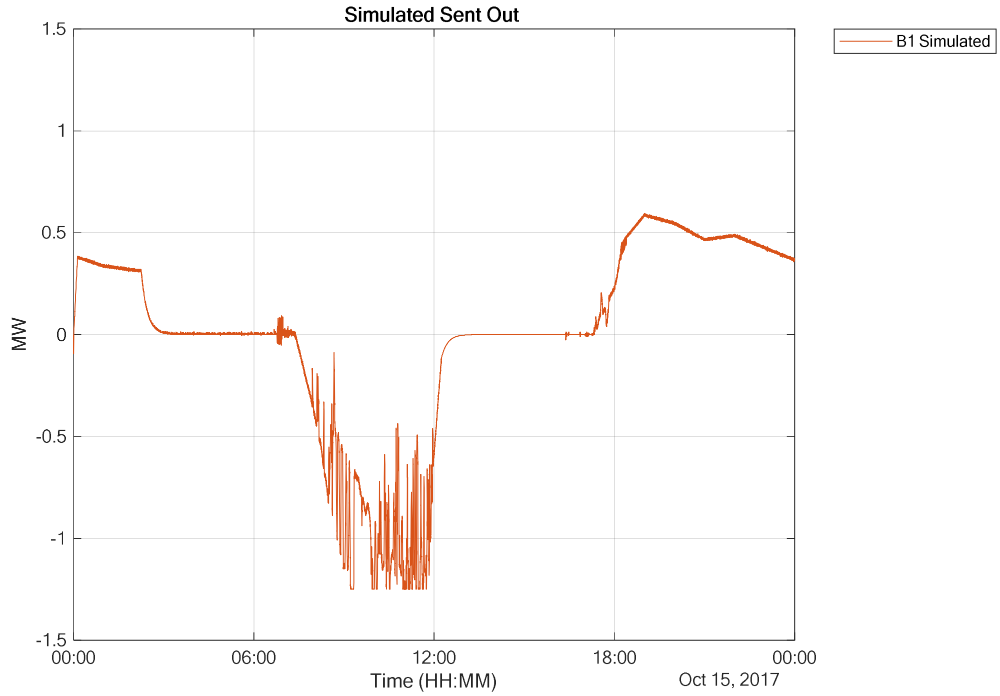


Figure 3-27 Simulated battery charge level for weekend when 1.25 MW / 5 MWh battery provides both primary frequency control and AGC with 2.3 MW of PV.

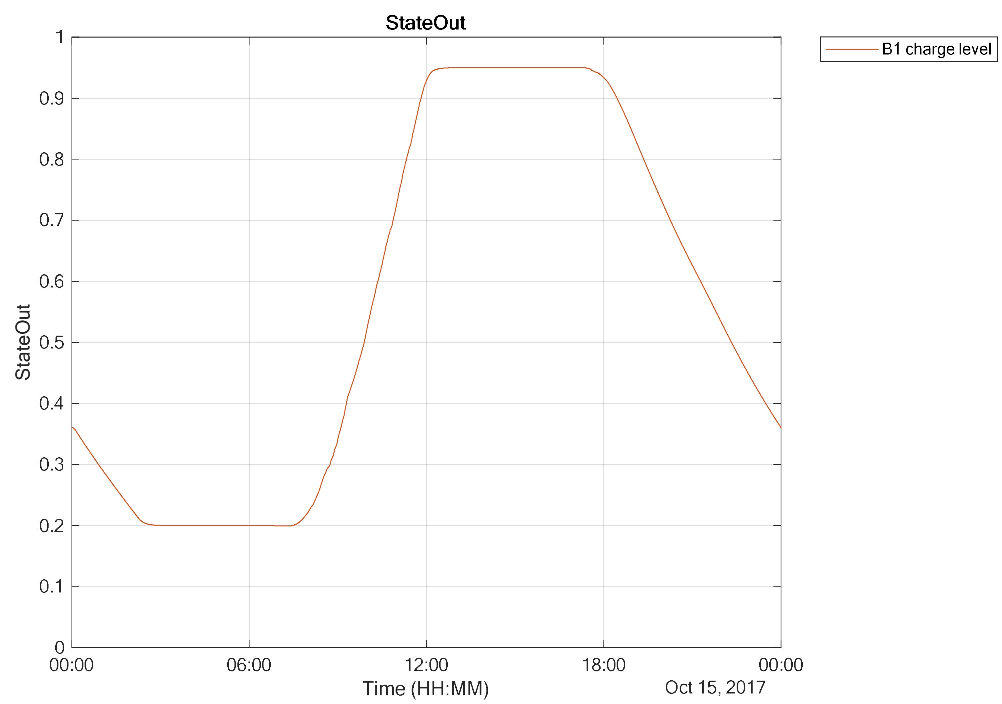
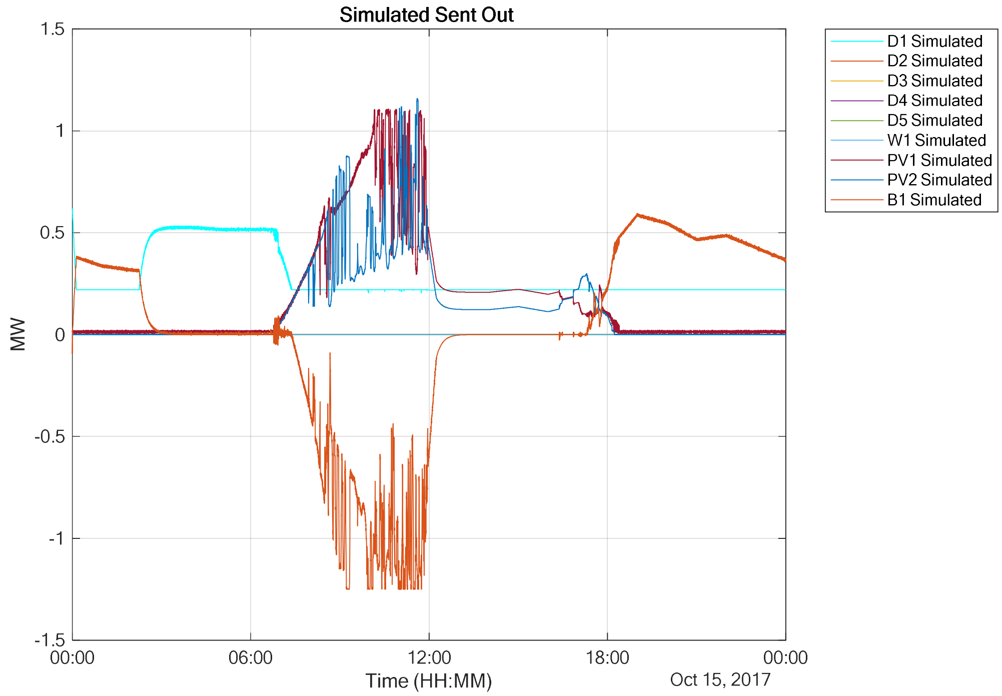


Figure 3-28 Simulated generator outputs for weekend when 1.25 MW / 5 MWh battery provides both primary frequency control and AGC with 2.3 MW of PV.



<u>Case 5: Weekday – 2.3 MW of PV and 1.25 MW / 5 MWh battery on AGC and all diesel off</u>

This case is a repeat of Case 4 but now the last diesel unit is allowed to go off line. In case 4 the 4.5 MWh of PV power is spilt which equates to 37.5 % of energy lost. The simulated frequency is within acceptable limits even when the last unit is off, as shown in Figure 3-29. There are a few frequency excursions which means the inverter size is adequate could be bigger as it is often at full charge MW output level, as shown in Figure 3-30. The battery fully discharges by midnight with diesel unit off.

The energy not utilised reduces to 2.6 MWh or 21.7% of energy lost. Taking the unit off saves an extra US$670 on the simulation day with the reduction in diesel fuel alone. This case has a net profit of $ 417 for the simulation day.

Figure 3-29 Simulated frequency for weekend when 1.25 MW / 5 MWh battery provides both primary frequency control and AGC with 2.3 MW of PV. All diesel units allowed to go off.

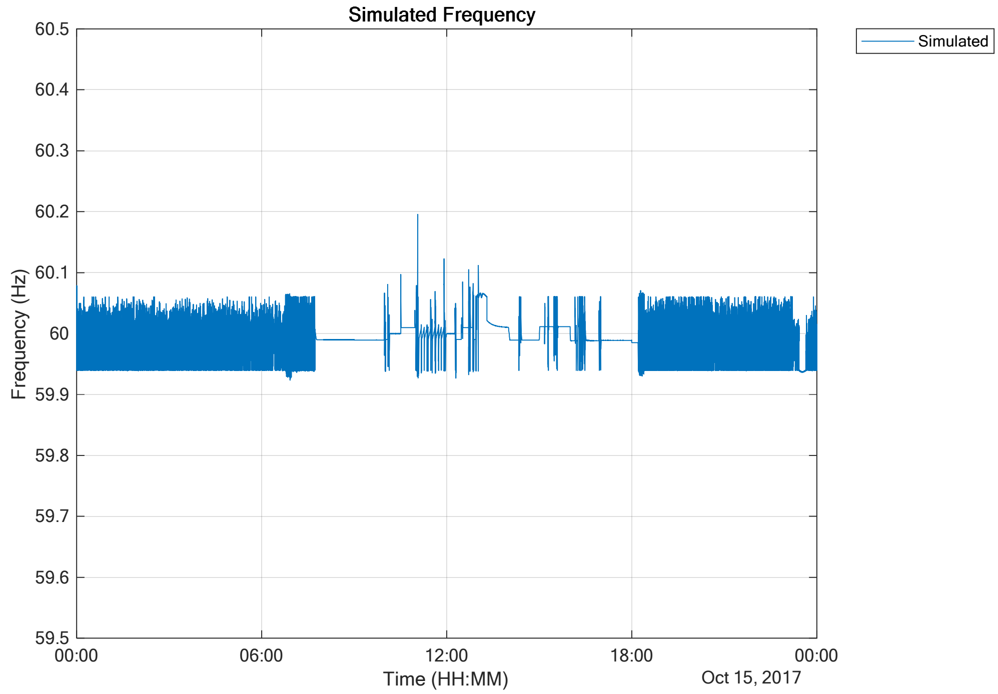
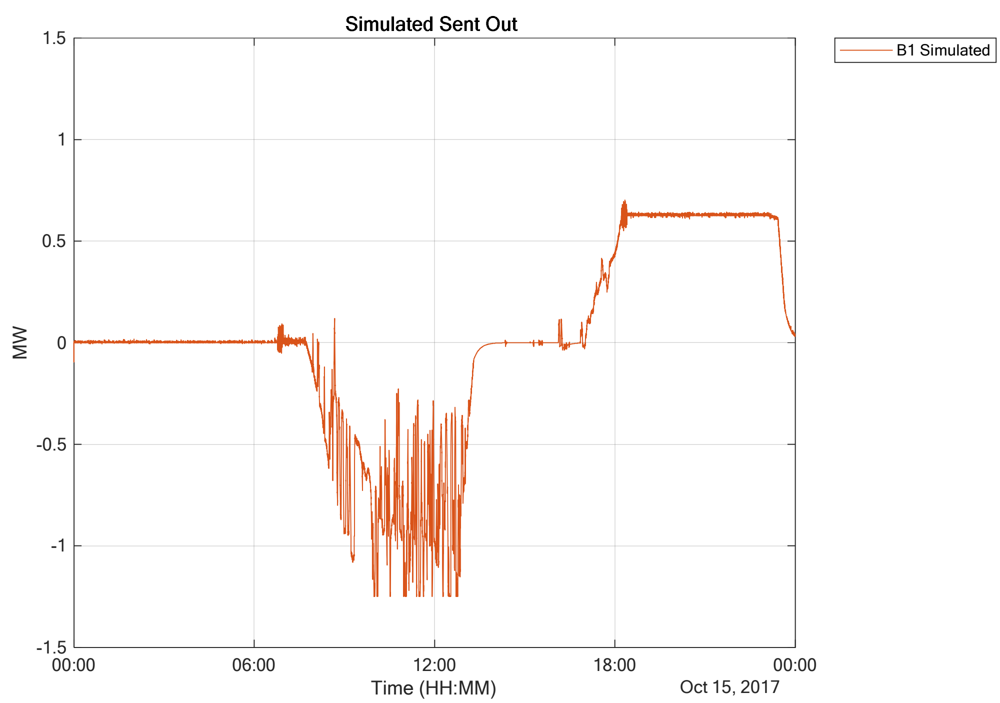


Figure 3-30 Simulated battery output for weekend when 1.25 MW / 5 MWh battery provides both primary frequency control and AGC with 2.3 MW of PV. All diesel units allowed to go off.



Case 6: Weekend – 4.3 MW of PV and 2.5 MW / 13 MWh battery on AGC and all diesel off

Case 6 is simulating the same as Case 5 but now 4.3 MW of PV and with assistance of 2.5 MW / 13 MWh battery on AGC as proposed by FSM Energy Master Plan Study, April 2018 and diesel allowed to go off.

Figure 3-31 shows the when battery simulated outputs when put on primary frequency control and AGC, the batteries use the excess PV to charge the battery almost full charge level, as shown in Figure 3-32, by 12:00. The batteries then discharge instead of using diesel generation from 17:00 Hrs until the next day discharging to a level is 35%. No diesel is required for the simulation day. The battery and PV is controlling the frequency for the whole period, as shown in Figure 3-33. Figure 3-34 shows the simulated frequency and when the PV is at its peak output and the battery is charging there is no sufficient control range to control the frequency. The frequency excursions are with the range of 59.5 to 60.5 Hz but the deviations are too big and too often so higher level of battery inverter is recommended.

The fuel costs for Case 6 is $ 107 for the very short period at the beginning of the simulation when the diesel is switched off. There is more than sufficient PV output to charge the batteries and is later discharged instead of using diesel power. The fuel cost savings is $3,498 however the additional simulated PV costs are $2,104 (with 38% of energy not utilised) and battery costs are estimated to be $ 2,104 for the simulation day. This case has a net loss of $ 533 for the simulation day.

Figure 3-31 Simulated battery output for weekend when 2.5 MW / 13 MWh battery provides both primary frequency control and AGC with 4.3 MW of PV.

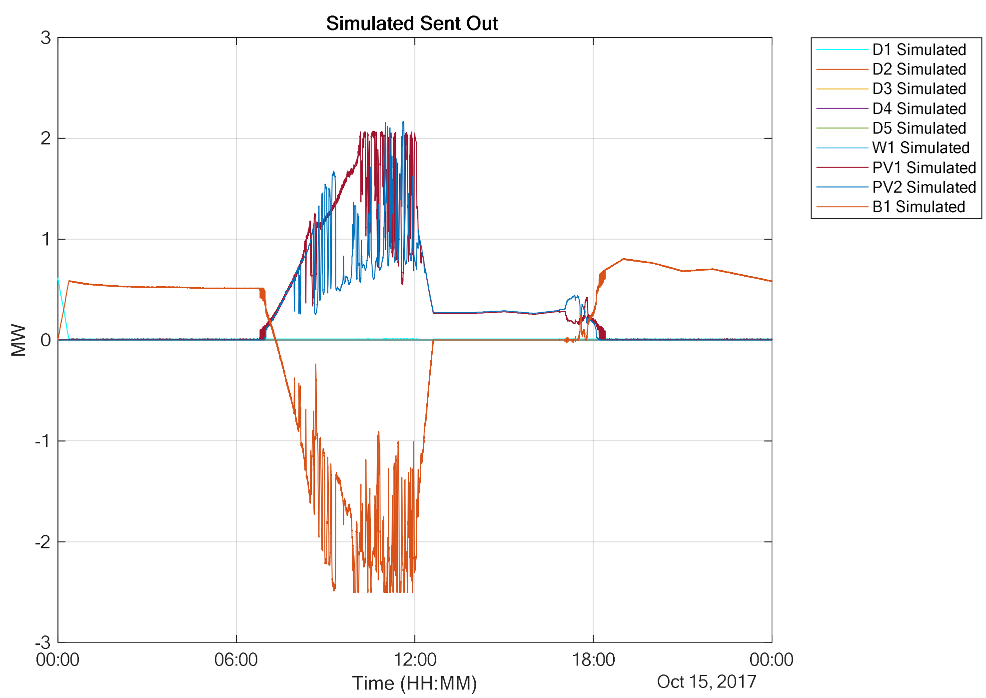


Figure 3-32 Simulated battery charge level for weekend when 2.5 MW / 13 MWh battery provides both primary frequency control and AGC with 4.3 MW of PV.

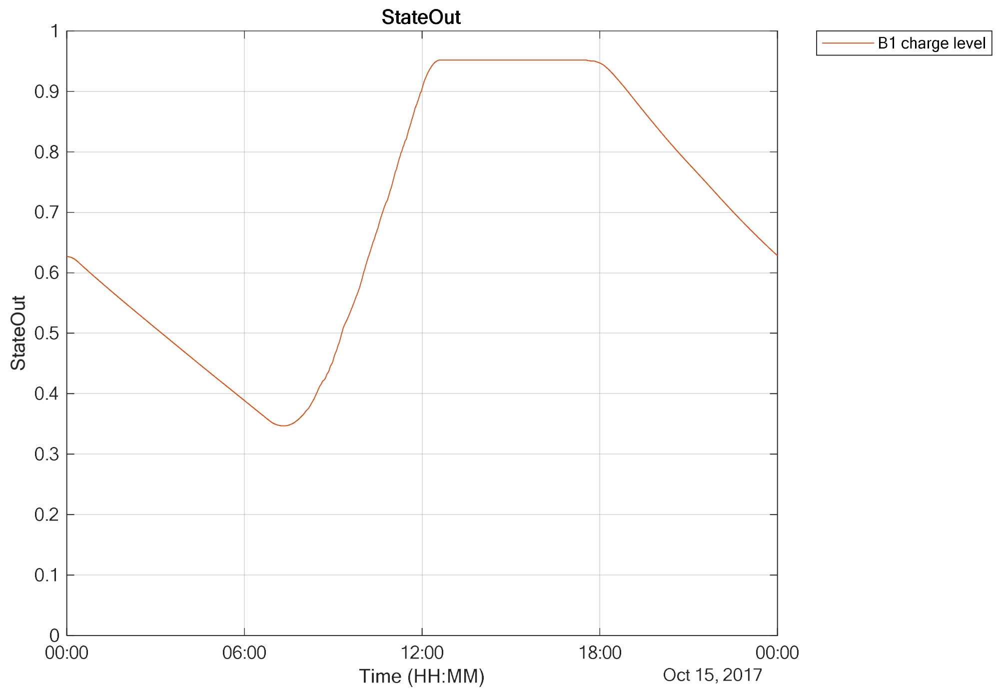


Figure 3-33 Simulated generator outputs for weekend when 2.5 MW / 13 MWh battery provides both primary frequency control and AGC with 4.3 MW of PV.

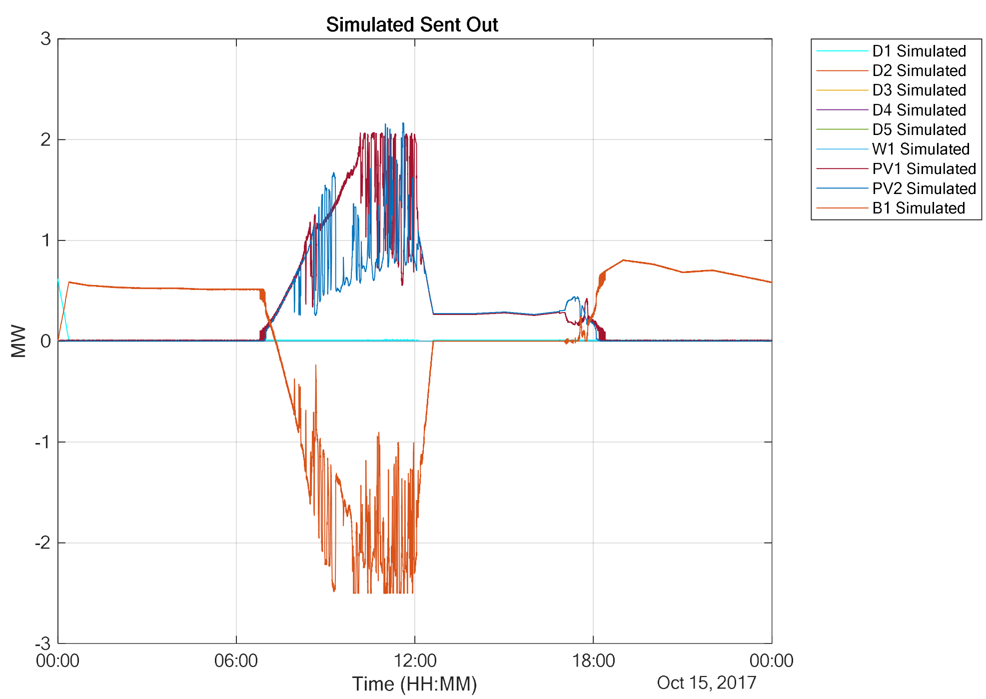
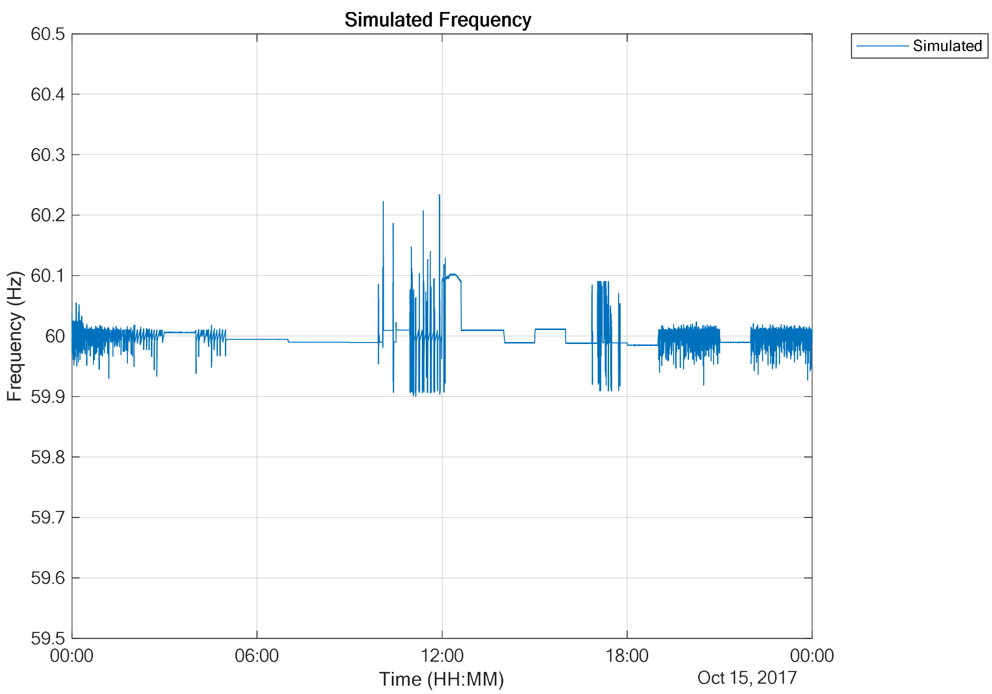


Figure 3-34 Simulated frequency for weekend when 2.5 MW / 13 MWh battery provides both primary frequency control and AGC with 4.3 MW of PV.



3.3.2 Base Case 2 & Simulation cases 7 – 12 Weekend with PV from 28 March 16

<u>Base Case 2: Weekend - Simulation of original PV with Tonga PV data from 28 March 16</u>

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data. Figure 3-35shows the simulation of generation unit outputs for a typical week day, with PV from Tonga on 28 March 16. This is the base case for these simulations where we can compare techno-economic impact of cases 7 to 12. The simulated frequency, as shown in Figure 3-36, shows the expected frequency variations without any frequency deviations from normal second to second changes in load.

Figure 3-35 Simulated generation on weekday with current installed PV

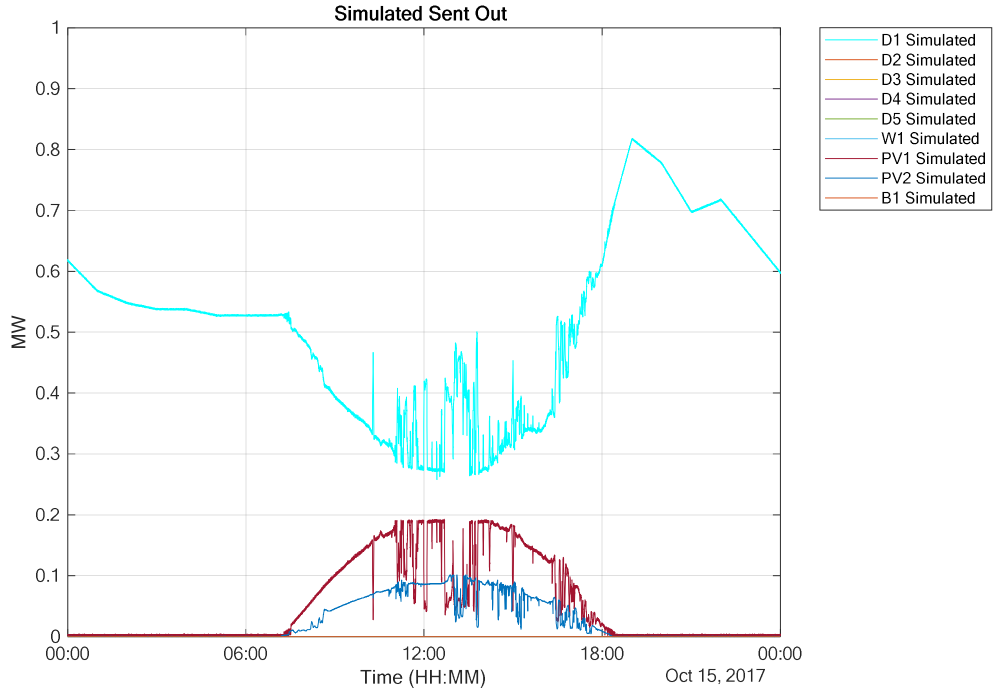
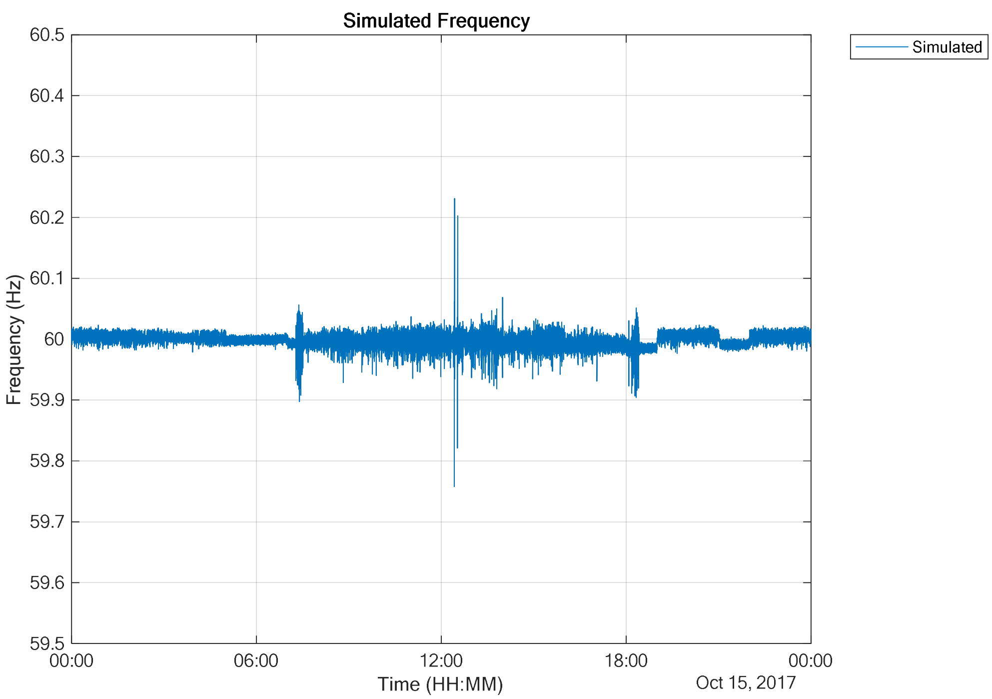


Figure 3-36 Simulated frequency on weekday with current installed PV



Case 7 - 12: Weekend – Repeat of cases 1-6 with PV from 28 March 16.

Cases 7 – 12 is the repeat of the simulations for a typical weekday but with a PV output from Tonga recorded on 28 March 16. The simulated frequency is within an acceptable range for case 7 with 1 MW total PV simulated, as shown in Figure 3-37, but the simulated frequency control is worse with the more volatile PV variations. Case 8 with 1 MW of simulated PV with a 0.5 MW battery on primary frequency control results in an acceptable frequency control within acceptable limits of 59.5 to 60.5 Hz, as shown in Figure 3-38. Case 9 with 2.3 MW of simulated PV with a 0.5 MW battery on primary frequency control results in an acceptable frequency control, as shown in Figure 3-39. Case 10 with the 2.3 MW of PV and 0.5 MW / 5 MWh battery on AGC has a very similar same result as for case 5. The same for Case 11 when the last diesel unit is allowed to off the battery has sufficient charge capacity to keep diesel off unit midnight.

Case 12 with 4.3 MW of PV and 2.5 MW / 13 MWh battery on AGC and all diesel off has similar results to case 6. Diesel units can be kept off the whole day and the excess PV is sufficient to fully charge the battery during the day, as shown in Figure 3-40. The surplus unused PV for this case is 12.8 MWh or 48% of capacity available.

Table 3-4 Comparison of daily fuel saving and net savings for a weekday with different PV input data

Simulation description	Case 1 - 6 daily diesel fuel savings	Case 7 - 12 daily diesel fuel savings	Case 1 - 6 daily net savings	Case 7 - 12 daily net savings
1 MW PV battery off	487	463	119	1
1 MW PV 0.5 MW battery on gov	487	454	-25	-151
2.3 MW PV 0.5 MW battery on gov	609	581	-587	-830
2.3 MW PV 1.25 MW / 5 MWh battery on gov & AGC	1,587	1,573	-253	-482
2.3 MW PV 1.25 MW / 5 MWh battery on gov & AGC and Diesel allowed to go off	2,257	2,208	417	152
4.3 MW PV 2.5 MW / 13 MWh battery on gov & AGC and Diesel allowed to go off	3,491	3,495	-533	-931

Figure 3-37 Case 7 - Simulated frequency on weekday with 1 MW PV

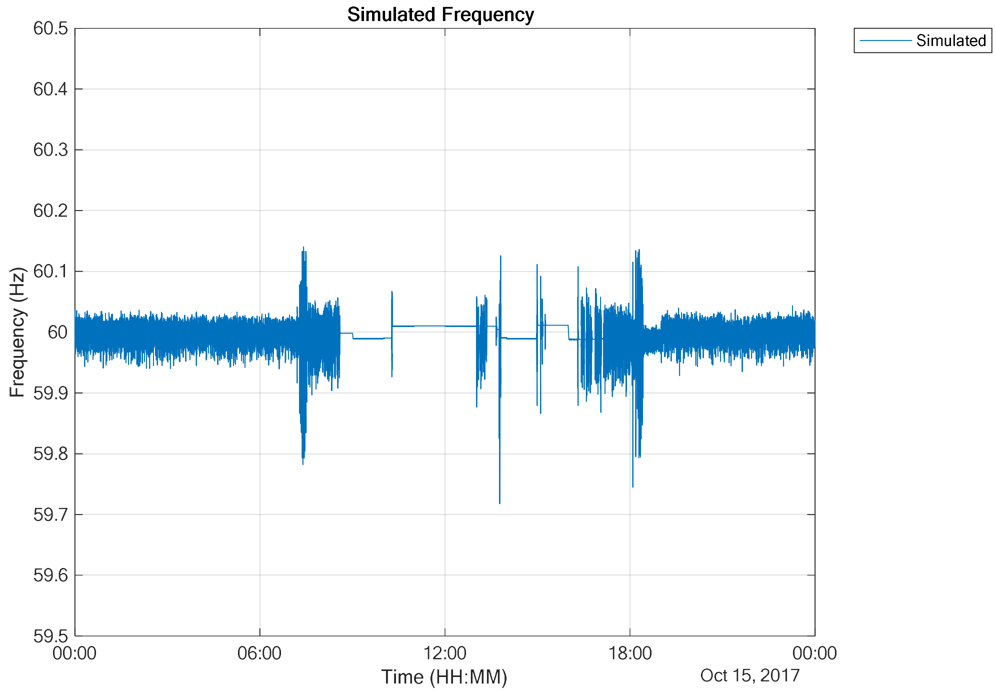


Figure 3-38 Case 8 - Simulated frequency on weekday with 1 MW PV and 0.5 MW battery on primary frequency control

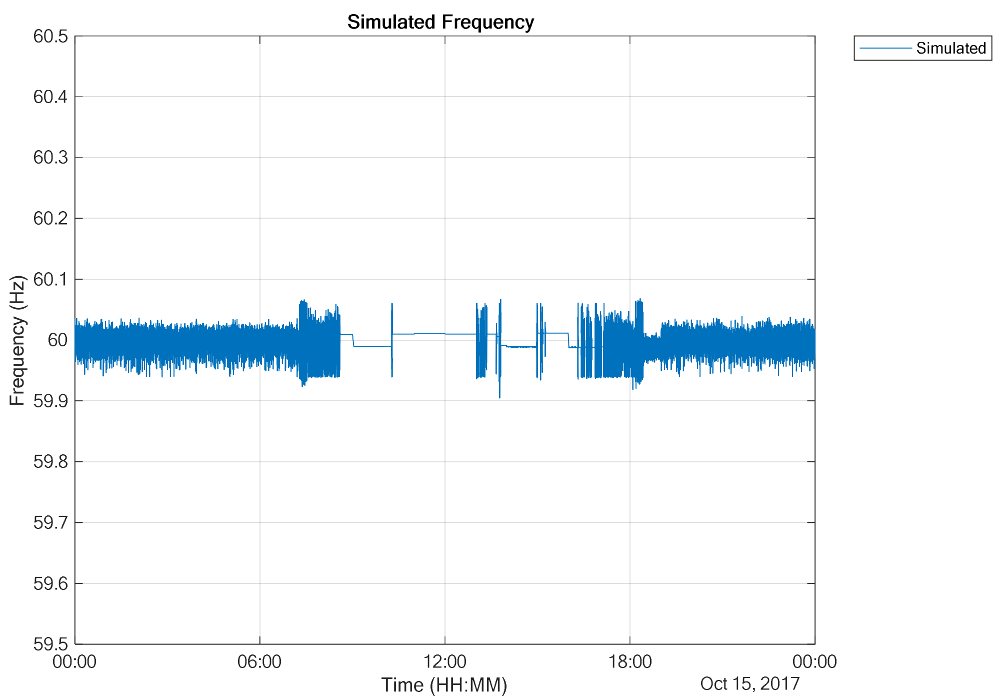


Figure 3-39 Case 9 - Simulated frequency on weekday with 2.3 MW PV and 0.5 MW battery on primary frequency control.

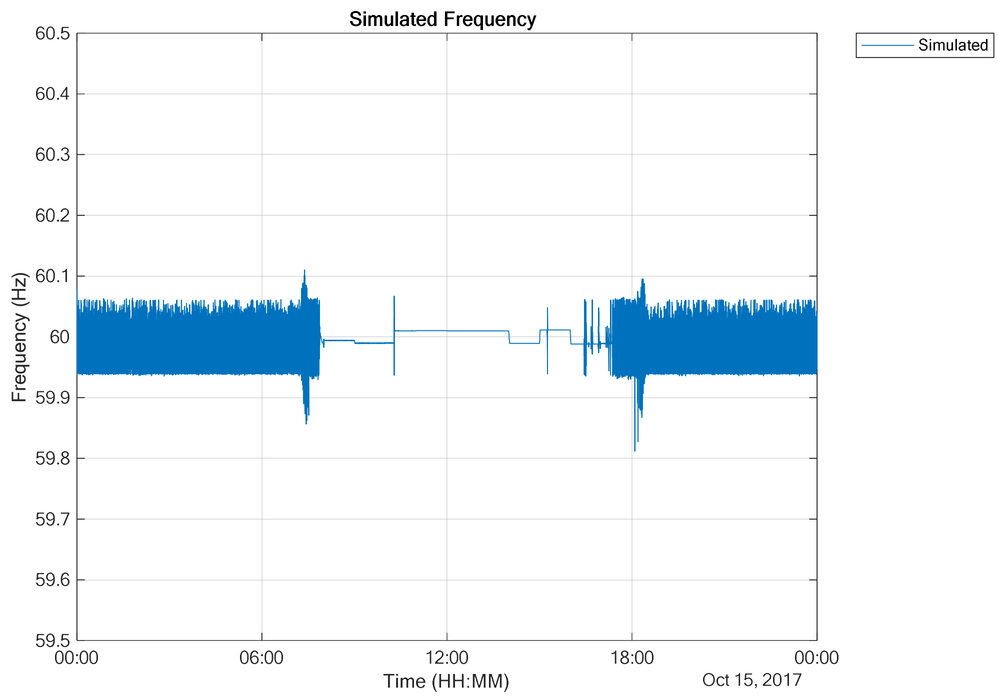
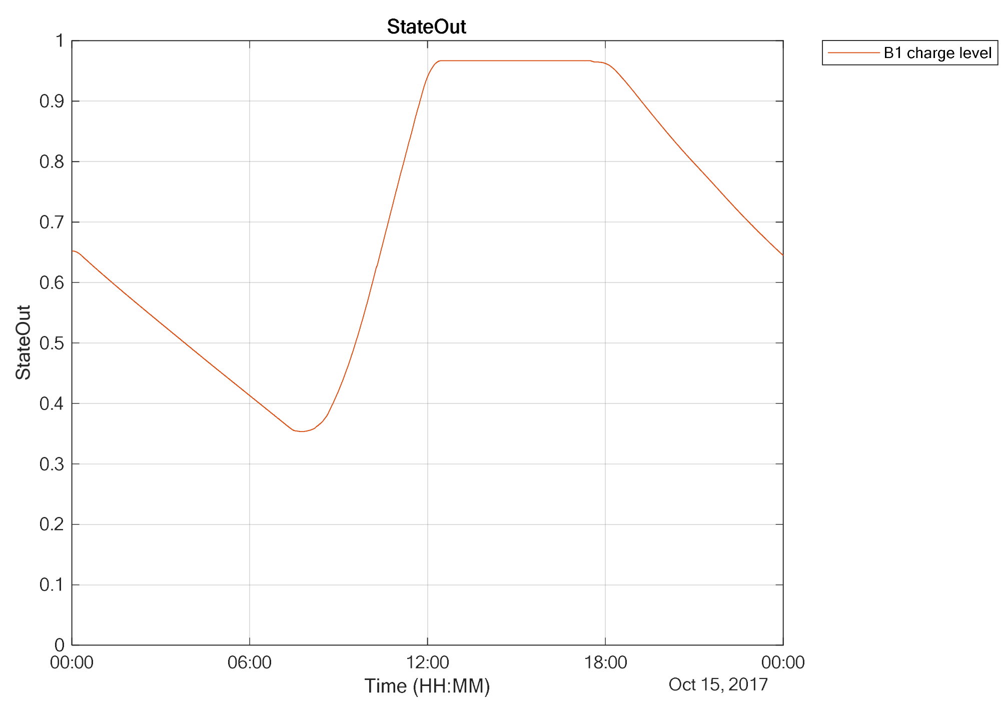


Figure 3-40 Case 12 - Simulated charge level on weekday with 4.3 MW PV and 2.5 MW / 13 MWh battery on AGC and all diesel units off.



3.3.3 Base Case 3 & Simulation cases 13 – 18 Weekend with PV from 02 October 2016

Base Case 3: Weekday - Simulation of original PV with Tonga PV data from 02 October 2016

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data. Figure 3-41 shows the simulation of generation unit outputs for a typical weekday, with PV from Tonga 02 October 2016. This is the base case for these simulations where we can compare techno-economic impact of cases 13 to 18. The simulated frequency, as shown in Figure 3-42, shows the expected frequency variations without any frequency deviations from normal second to second changes in load.

Figure 3-41 Simulated generation on weekday with current installed PV

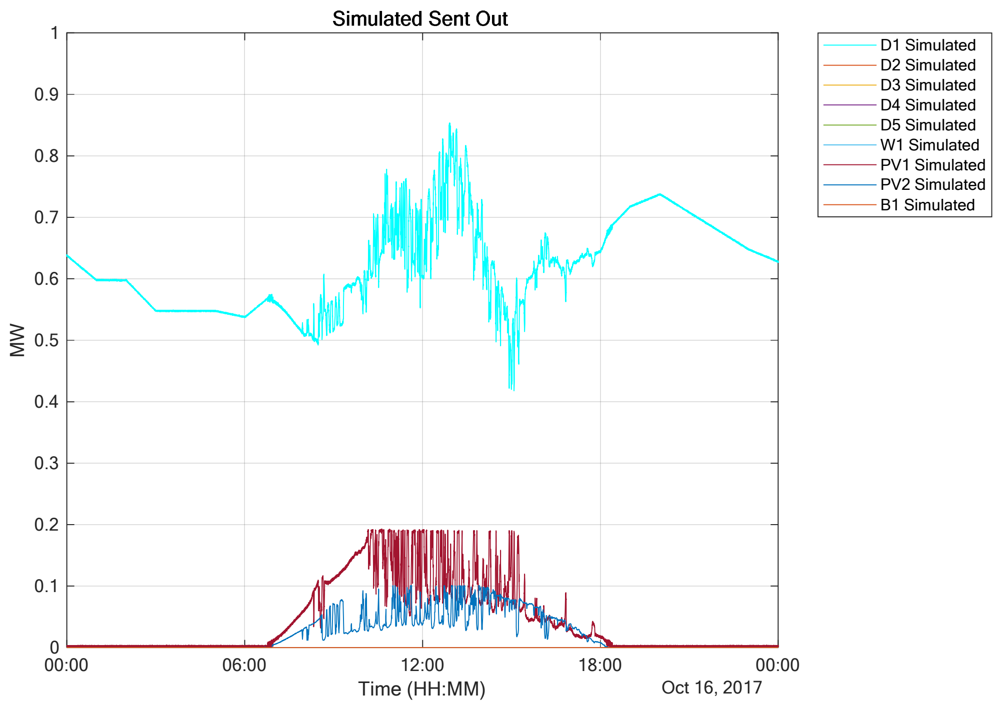
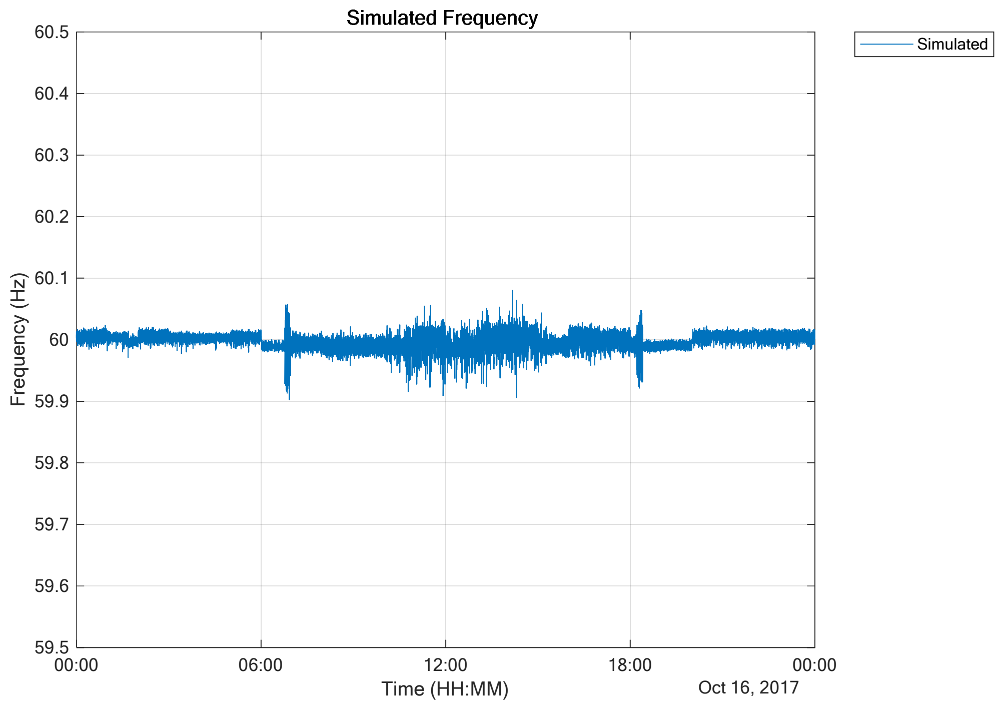


Figure 3-42 Simulated frequency on weekday with current installed PV



<u>Case 13: Weekday - 1 MW of PV with Tonga PV data from 02 October 2016</u>

For Case 13 the PV power plants are set to 0.5 MW each giving a total PV of 1 MW, Diesel units D1 is the only unit on to perform the control, as shown in Figure 3-43. The frequency is acceptable but there are frequency excursions where the Diesel Power plant is battling to control the frequency.

Figure 3-43 Simulated generation on weekday with 1 MW PV

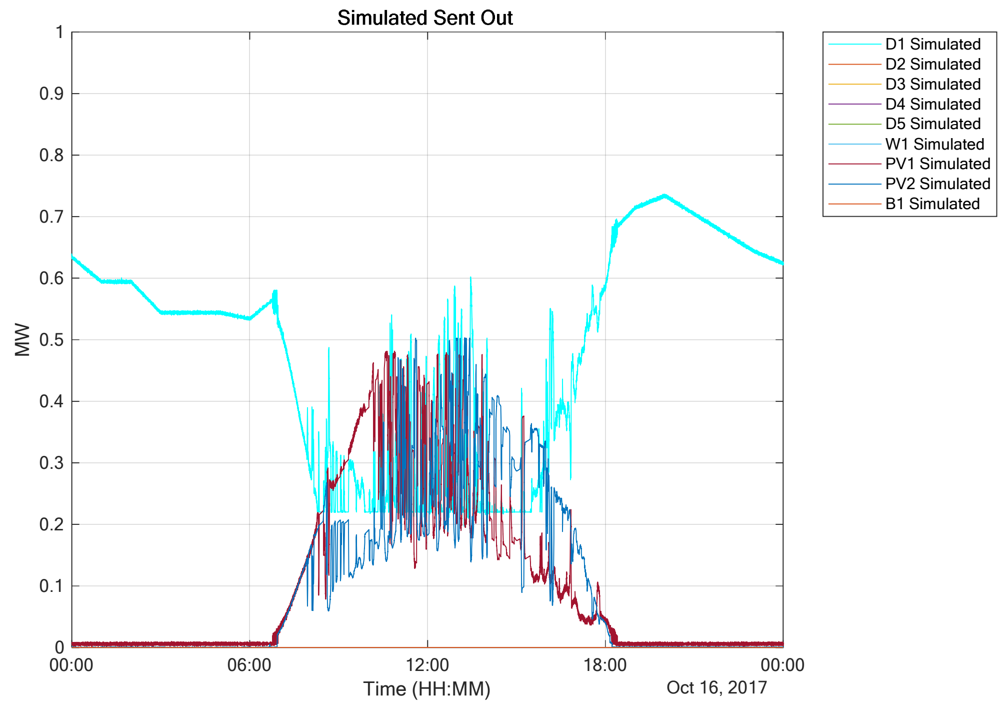
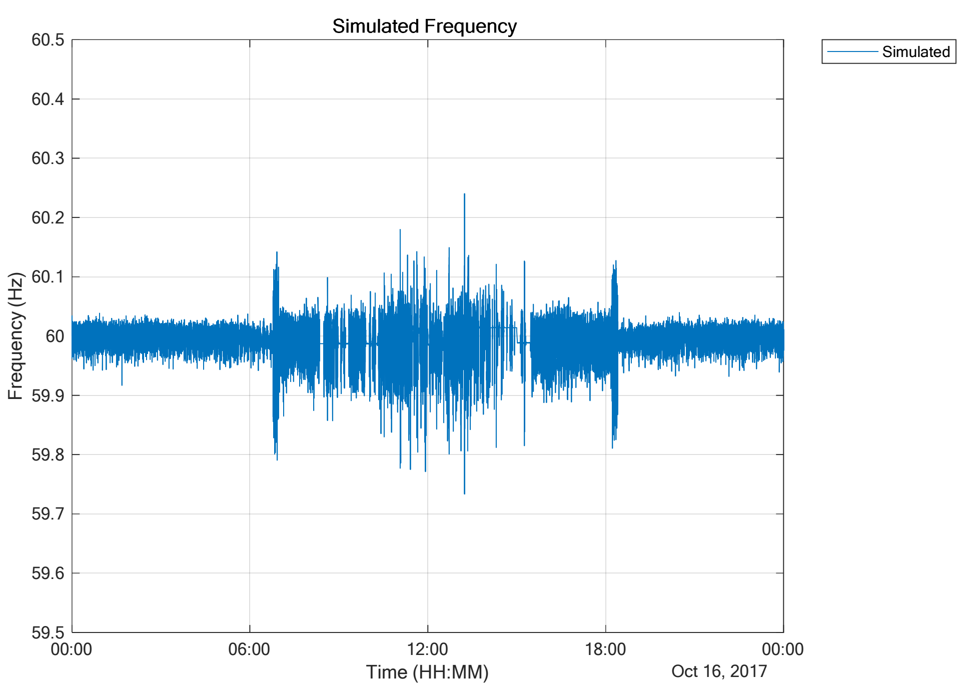


Figure 3-44 Simulated frequency on weekday with 1 MW PV



Case 14: Weekday - 1 MW of PV and 0.5 MW / 0.5 MWh battery on primary frequency control

Batteries can be used for primary frequency control only and thus only respond to frequency variations. For these simulations, the battery control parameters are shown in Figure 3-45. The deadband is set to 0.05 Hz and thus the battery will respond to frequency variations outside of this range and droop is set to 0.1 %, thus a 0.1% change in frequency will result in 100% change in power. Thus the battery will go from zero output to full output if the frequency drops from 59.95 to 59.9 Hz and similarly will go to from 0 to full charge with a frequency variation from 60.05 to 60.1 Hz.

Figure 3-45 Battery parameters when on primary frequency control only

Misc	
Unit Name	B1
Model type	Battery
MCR	0.5
Unit Inertia	0
Ramp Rate	200
Maximum Generation	0.5
Minimum Generation	-0.5
Spinning Capability	0.5
Nonspinning Capability	0
AGC On	False
Model Name	Battery
Frequency deadband	0.001
Lower frequency limit	-1
Upper frequency limit	1
Droop (R)	0.001

The simulated frequency improves when 0.5 MW battery is on primary frequency control only, as shown in Figure 3-46. There are a few occasions during the period when the battery is at fully charging and the response is not enough to prevent frequency excursion, as shown in Figure 3-47. The diesel fuel costs remain the same at $3,300 as for case 13 showing the battery is just performing primary frequency control and the battery on discharges a few percent, as shown in Figure 3-48. The net saving of US$ 342 is calculated for the simulation day including the battery costs.

Figure 3-46 Simulated frequency for weekday with 1 MW of PV and 0.5 MW battery on primary frequency control

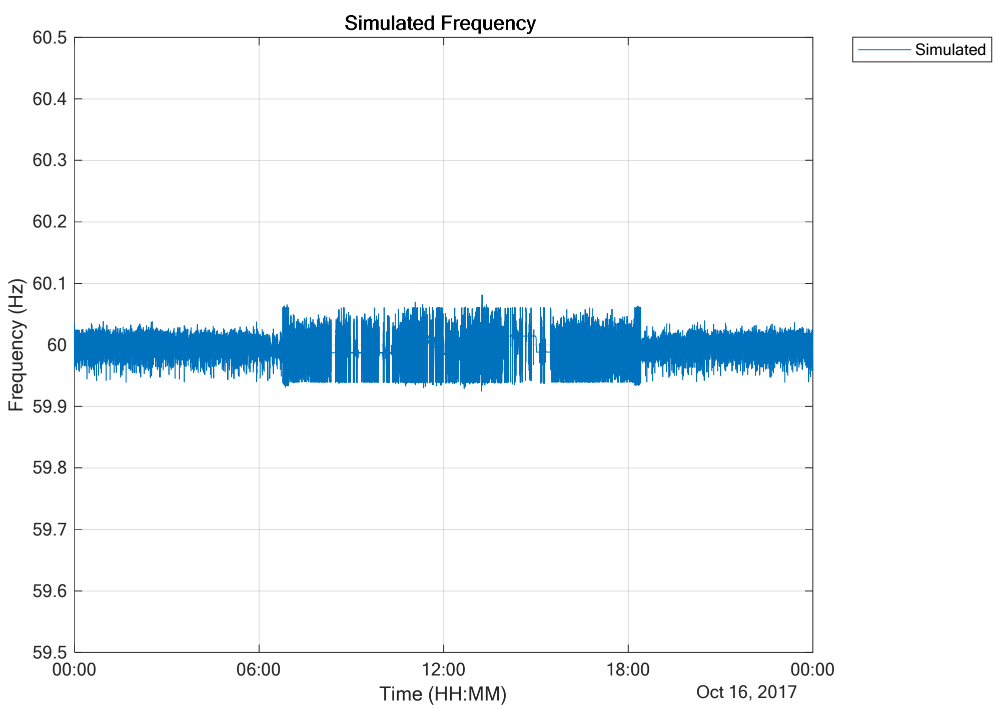


Figure 3-47 Simulated battery power for weekday with 1 MW of PV and 0.5 MW battery on primary frequency control

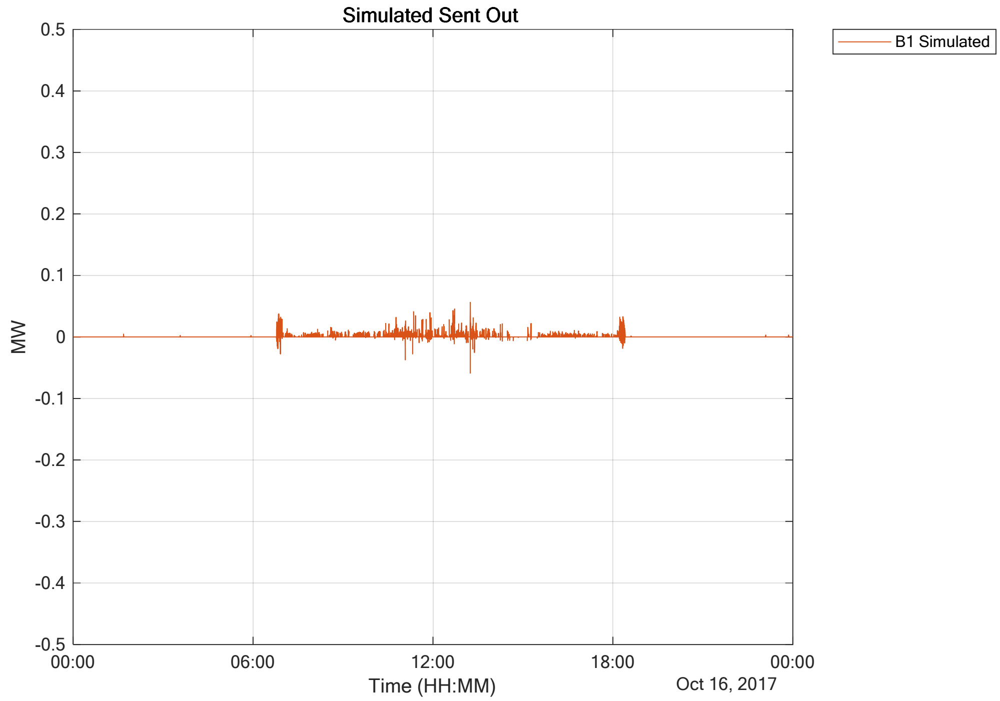
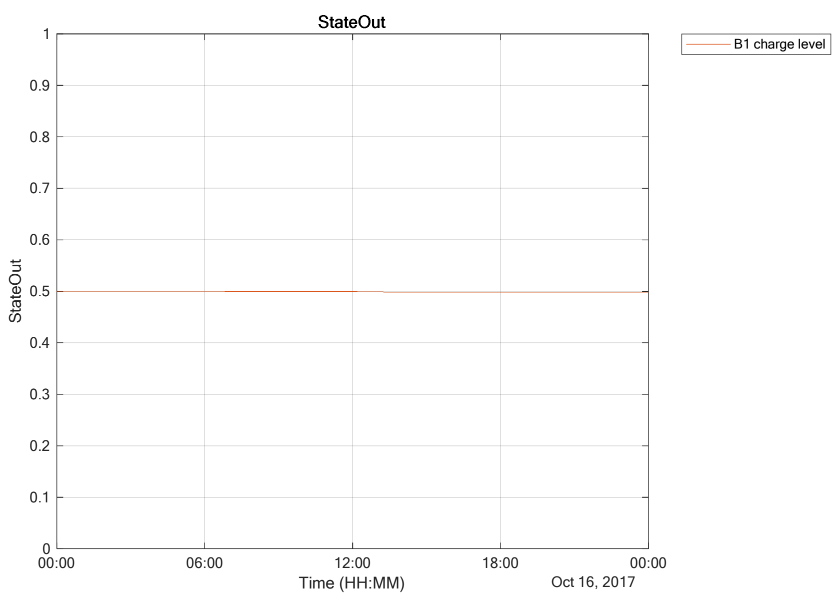


Figure 3-48 Simulated battery power for weekday with 1 MW of PV and 0.5 MW battery on primary frequency control



<u>Case 15: Weekday – 2.3 MW of PV and 0.5 MW / 0.5 MWh battery on primary frequency control</u>

For Case 15 the PV power plants are set to 1.15 MW each giving a total PV of 2.3 MW, Diesel unit 1 provides the secondary control under AGC to perform the control assisted by a 0.5 MW battery on primary frequency control, as shown in Figure 3-49 . The frequency is acceptable control well within the range of 59.5 to 60.5 Hz, as shown in

Figure 3-50. The battery full range is not fully utilised to control the frequency and so battery size is fine for frequency control for this simulation case, as shown in Figure 3-51.

Only 50.4% of the available energy from the 2.3 MW of PV is used resulting but still results in a fuel saving of US$1,147 but a net loss of US$ 45 for the simulation day.

Figure 3-49 Simulated generation for weekday with 2.3 MW of PV and 0.5 MW battery on primary frequency control

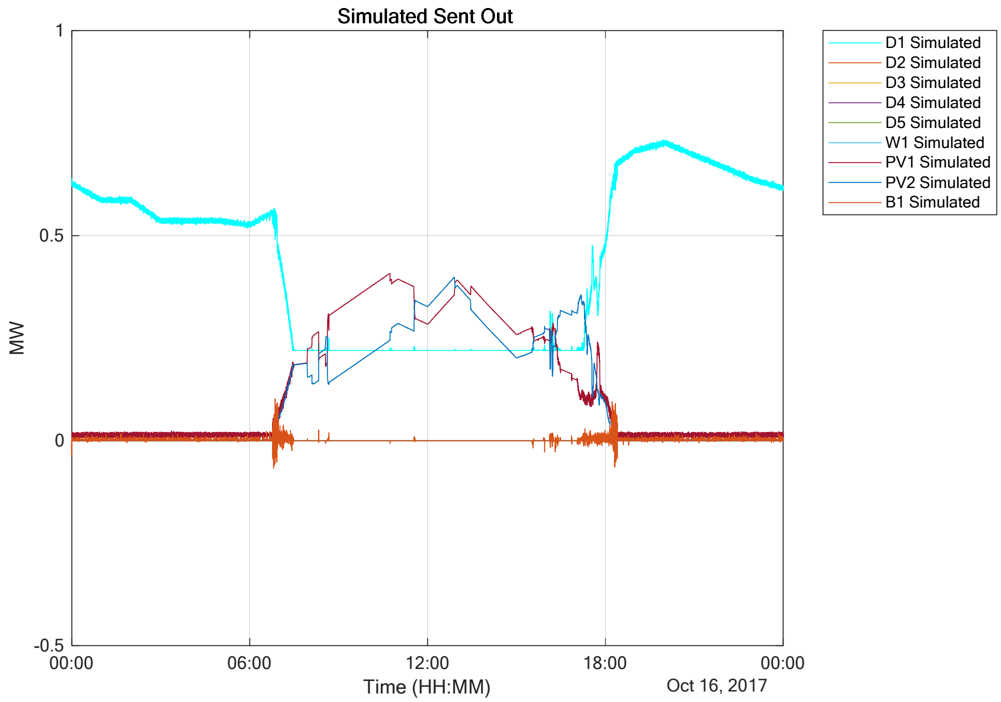


Figure 3-50 Simulated frequency for weekday with 2.3 MW of PV and 0.5 MW battery on primary frequency control

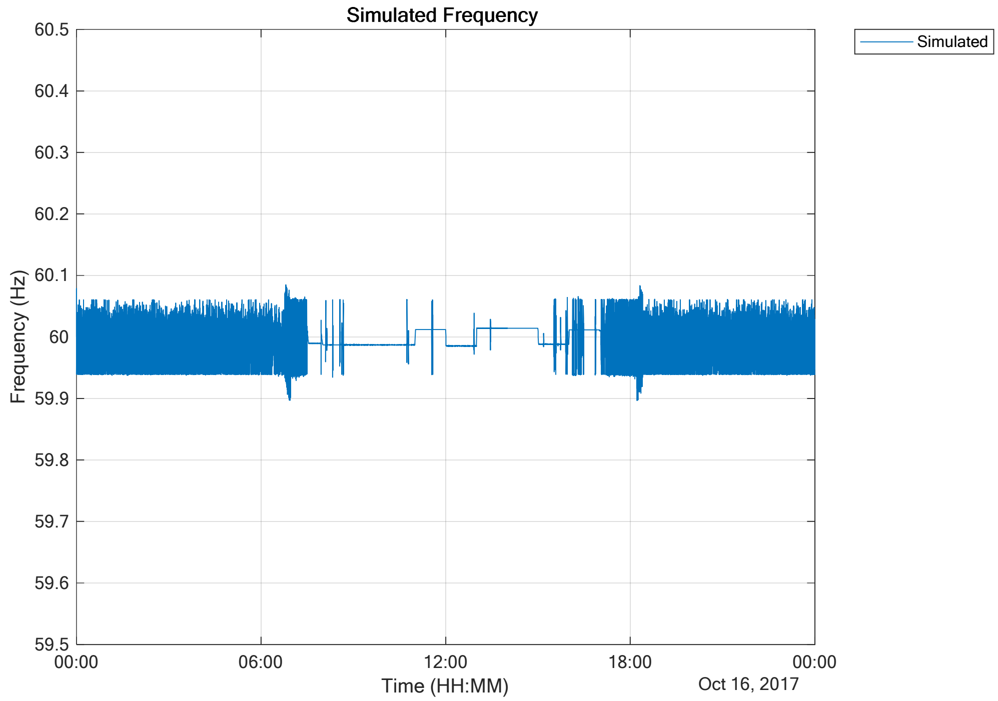
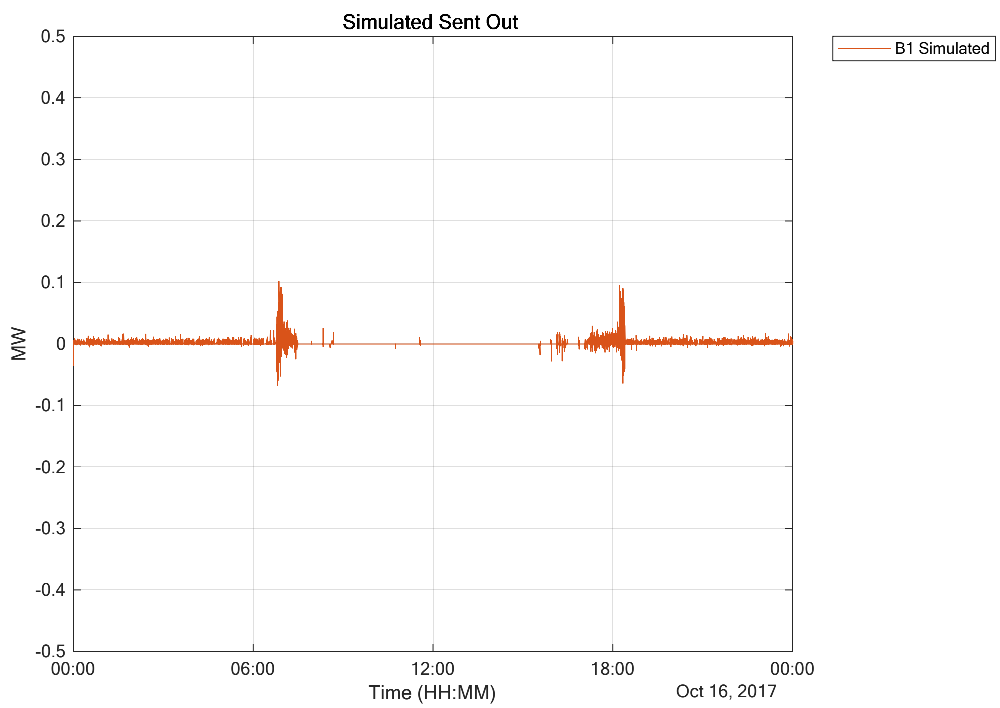


Figure 3-51 Simulated battery output for weekday with 2.3 MW of PV and 0.5 MW battery on primary frequency control



Case 16: Weekday – 2.3 MW of PV and 1.25 MW / 5 MWh battery on AGC

Case 16 is simulating the same as Case 15 but now with assistance of 1.25 MW / 5 MWh battery on AGC as proposed by FSM Energy Master Plan Study, April 2018. The batteries also provide primary frequency control as for the simulations above. The philosophy for the batteries under AGC control is:

1. Starting batteries with a charge of 20% - assuming batteries have been utilised the previous evening – update to actual midnight value to give a typical continuous day's profile (need to run simulation twice)
2. Battery is discharged whenever possible to displace diesel. Battery provide power at half their potential – keeping the remaining half available for primary frequency control
3. Battery is charged using any excess PV available – when PV exceeds demand minus diesel generation minimum demand. Battery is charge to 95% keeping some capacity for primary frequency control high frequency response after charging.
4. The discharge level is limited by the AGC controller to 50% of the battery size to ensure frequency is controlled at the same time as optimising the energy available – essentially system security before economics

Figure 3-52 shows the when battery simulated outputs when put on primary frequency control and AGC, the batteries use the excess PV to charge the battery almost full charge level, as shown in

Figure 3-53, by 13:00. The batteries then discharge instead of using diesel generation from 17:00 Hrs until charge level is 20% which is around 03:00 the next day. The simulated diesel generator 1 output is at minimum generation for most of the period from 07:30 Hrs to 03:00 Hrs the next day, as shown in Figure 3-54.

The fuel costs for Case 16 is $ 2,027 compared to $ 3,006 for Case 15. This reduction is due to an increase PV output of 3.7 MWh which is used to charge the batteries and is later discharged instead of using diesel power. Using the batteries on AGC in this simulation case saves an extra $335 on fuel costs. The daily cost for the batteries is calculated as $ 788 and this case has a net profit of $ 289.

Figure 3-52 Simulated battery output for weekday when 1.25 MW / 5 MWh battery provides both primary frequency control and AGC with 2.3 MW of PV.

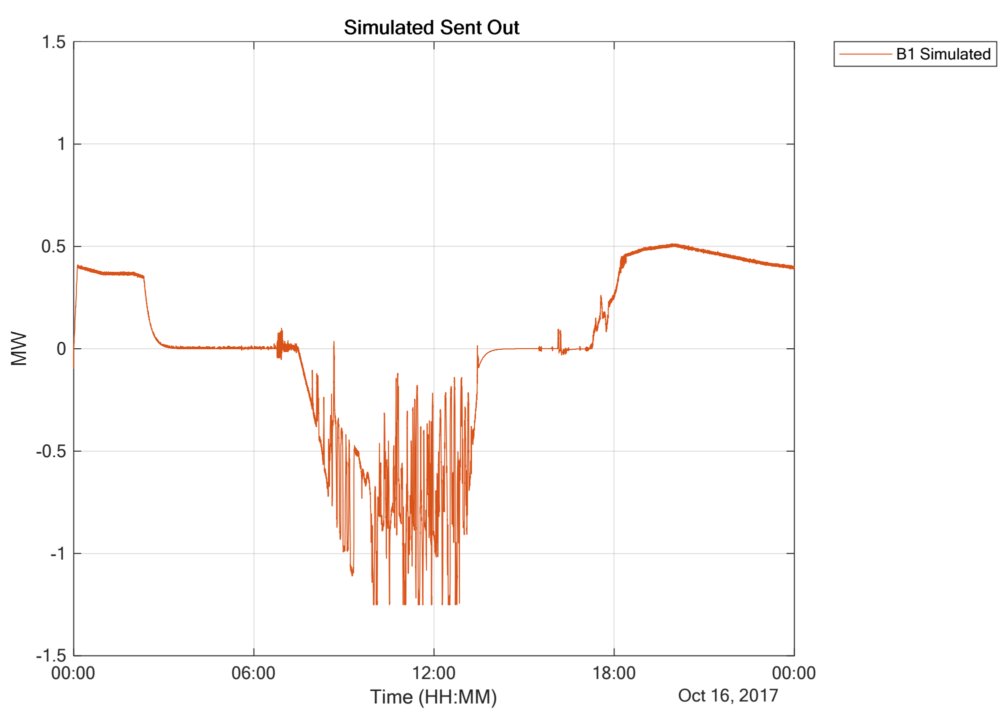


Figure 3-53 Simulated battery charge level for weekday when 1.25 MW / 5 MWh battery provides both primary frequency control and AGC with 2.3 MW of PV.

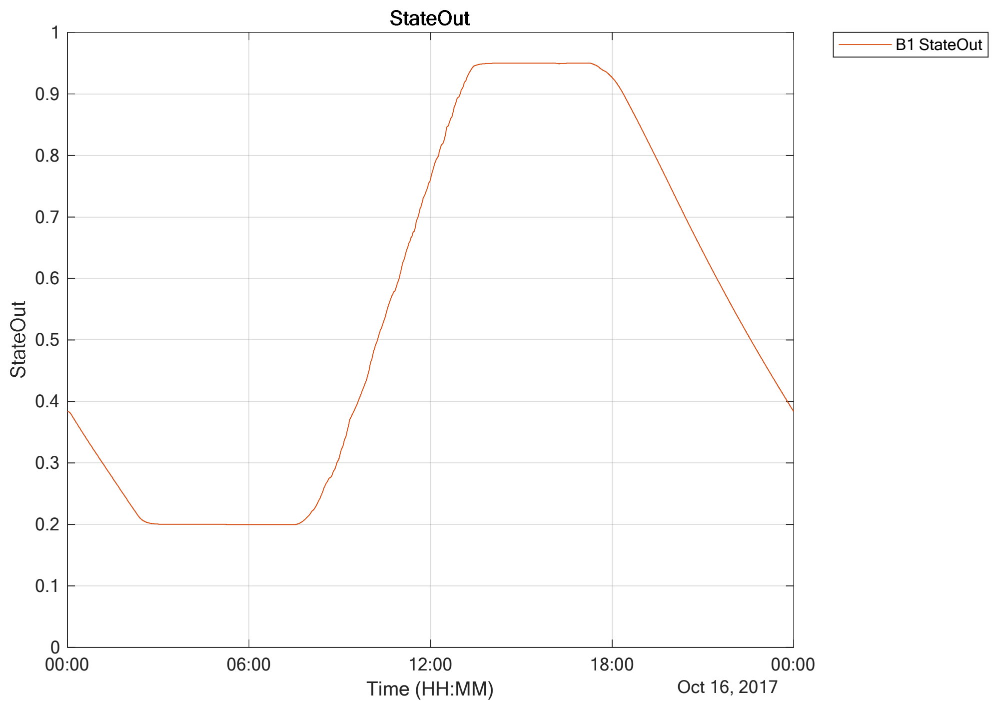
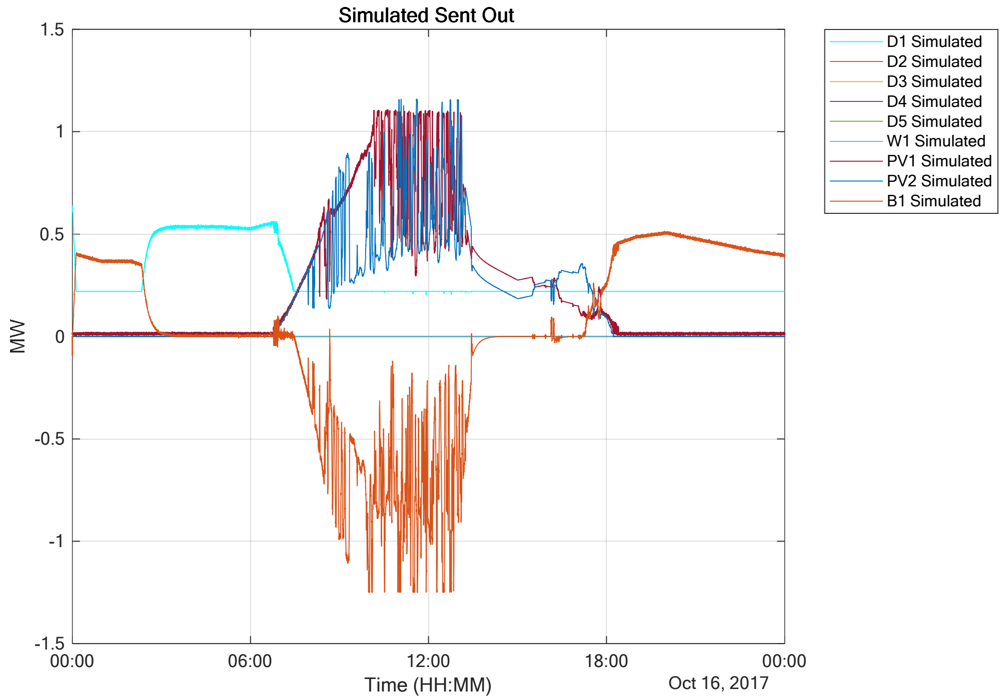


Figure 3-54 Simulated generator outputs for weekday when 1.25 MW / 5 MWh battery provides both primary frequency control and AGC with 2.3 MW of PV.


Simulated Sent Out
1.5
1
0.5
0
-0.5
-1
-1.5
MW
00:00
06:00
12:00
18:00
00:00
Time (HH:MM)
Oct 16, 2017
D1 Simulated
D2 Simulated
D3 Simulated
D4 Simulated
D5 Simulated
W1 Simulated
PV1 Simulated
PV2 Simulated
B1 Simulated

Case 17: Weekday – 2.3 MW of PV and 1.25 MW / 5 MWh battery on AGC and all diesel off

This case is a repeat of Case 16 but now the last diesel unit is allowed to go off line. In case 16 the 2.3 MWh of PV power is spilt which equates to 19.3 % of energy lost however case 17 only has 3.1% spilt energy. The simulated frequency is within acceptable limits even when the last unit is off, as shown in

Figure 3-55. There are a few frequency excursions which means the inverter size is adequate could be bigger as it is often at full charge MW output level, as shown in Figure 3-56. The battery fully discharges by midnight with diesel unit off.

The energy spilt reduces to 0.4 MWh or 10.7% reduction. Taking the unit off saves an extra US$650 on the simulation day with the reduction in diesel fuel alone. This case has a net saving of $ 939 for the simulation day.

Figure 3-55 Simulated frequency for weekday when 1.25 MW / 5 MWh battery provides both primary frequency control and AGC with 2.3 MW of PV. All diesel units allowed to go off.

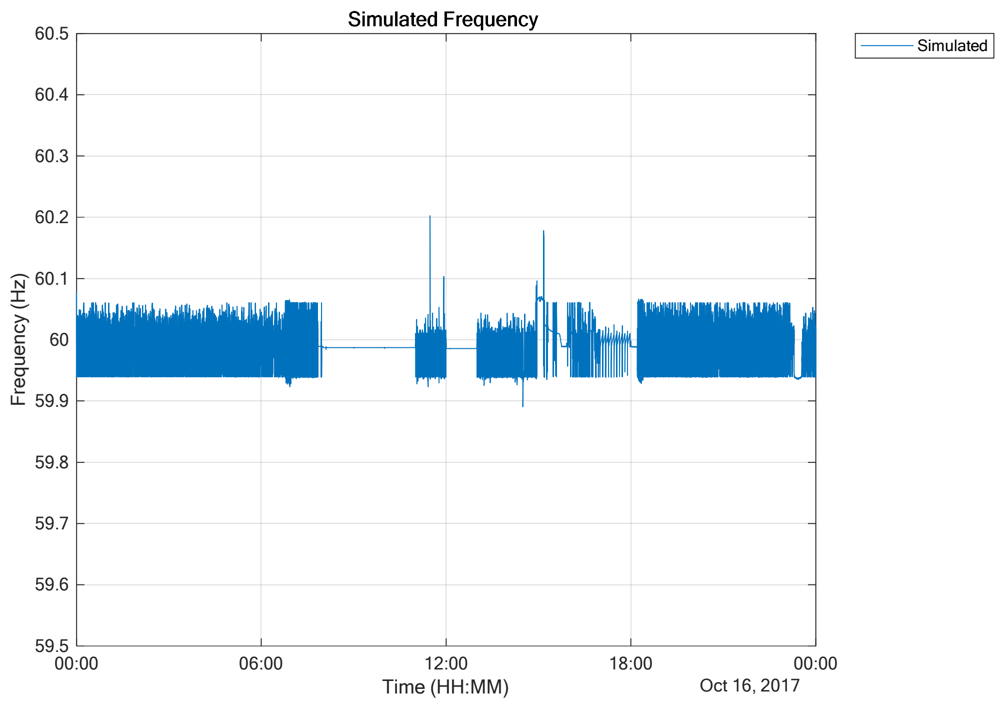
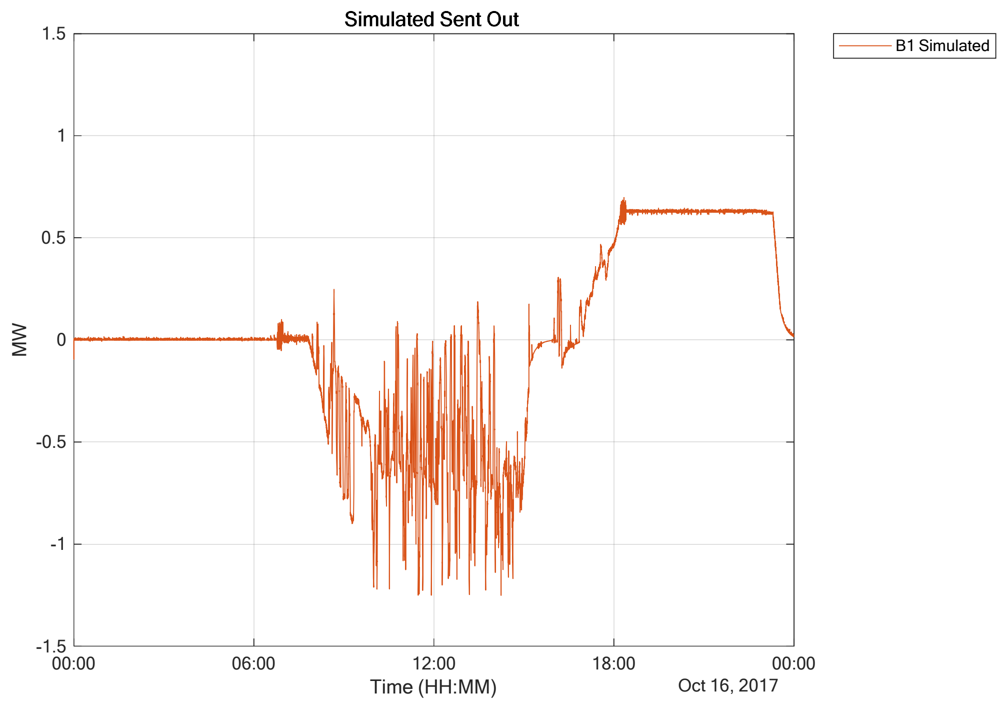


Figure 3-56 Simulated battery output for weekday when 1.25 MW / 5 MWh battery provides both primary frequency control and AGC with 2.3 MW of PV. All diesel units allowed to go off.



Case 18: Weekday – 4.3 MW of PV and 2.5 MW / 13 MWh battery on AGC and all diesel off

Case 18 is simulating the same as Case 17 but now with 4.3 MW of PV and with assistance of 2.5 MW / 13 MWh battery on AGC as proposed by FSM Energy Master Plan Study, April 2018 and diesel allowed to go off.

Figure 3-57 shows the when battery simulated outputs when put on primary frequency control and AGC, the batteries use the excess PV to charge the battery almost full charge level, as shown in Figure 3-58, by 13:00. The batteries then discharge instead of using diesel generation from 18:00 Hrs until the next day discharging to a level is 35%. No diesel is required for the simulation day. The battery and PV is controlling the frequency for the whole period, as shown in Figure 3-59. Figure 3-60 shows the simulated frequency and when the PV is at its peak output and the battery is charging there is no sufficient control range to control the frequency. The frequency excursions are with the range of 59.5 to 60.5 Hz but the deviations are too big and too often so higher level of battery inverter is recommended.

The fuel costs for Case 18 is $ 109 for the very short period at the beginning of the simulation when the diesel is switched off. There is more than sufficient PV output to charge the batteries and is later discharged instead of using diesel power. The fuel cost savings is $4,044 however the additional simulated PV costs are $2,097 (with 27.8% of energy not utilised) and battery costs are estimated to be $ 1.920 for the simulation day. This case has a net saving of $ 27 for the simulation day.

Figure 3-57 Simulated battery output for weekday when 2.5 MW / 13 MWh battery provides both primary frequency control and AGC with 4.3 MW of PV.

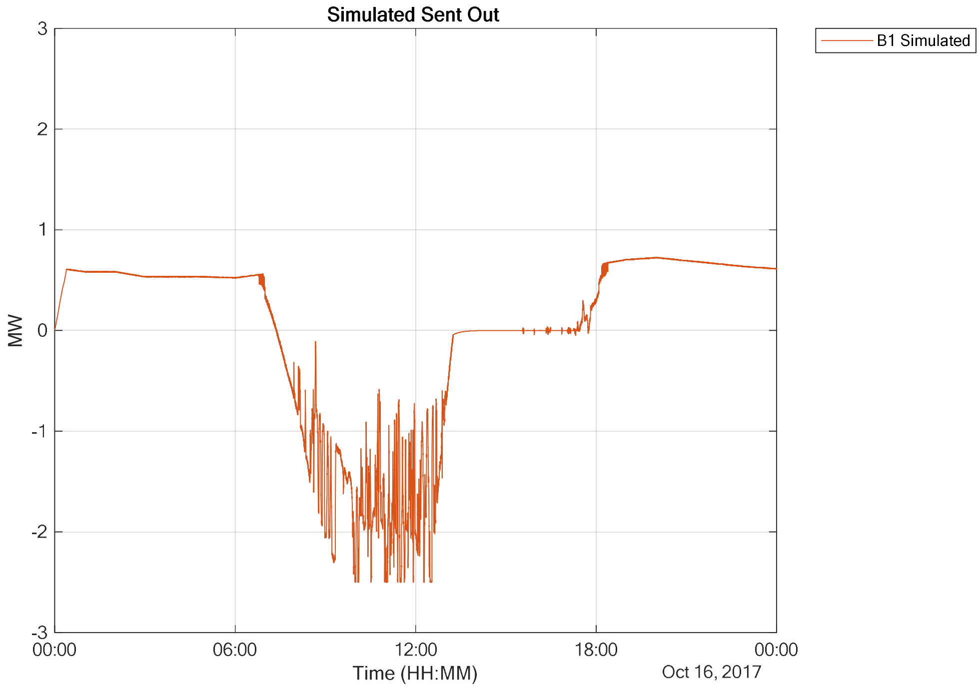


Figure 3-58 Simulated battery charge level for weekday when 2.5 MW / 13 MWh battery provides both primary frequency control and AGC with 4.3 MW of PV.

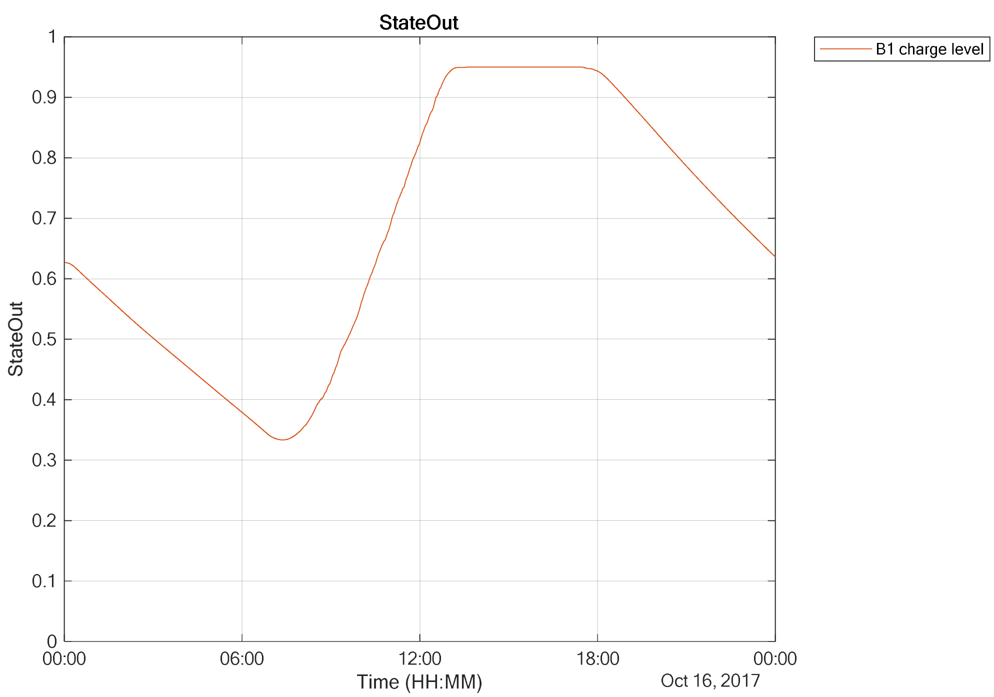


Figure 3-59 Simulated generator outputs for weekday when 2.5 MW / 13 MWh battery provides both primary frequency control and AGC with 4.3 MW of PV.

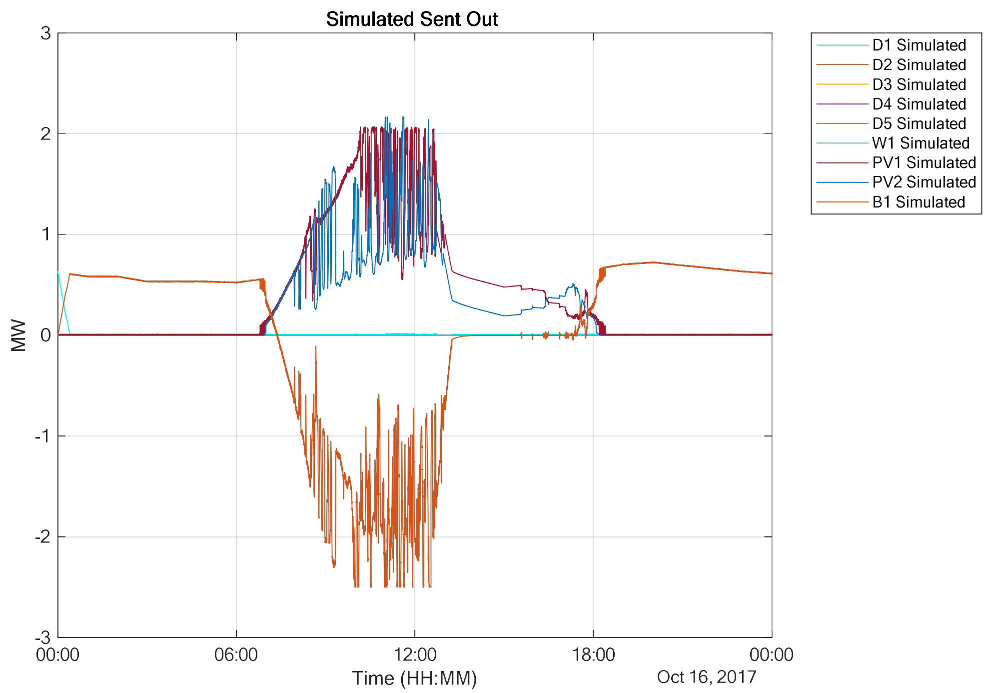
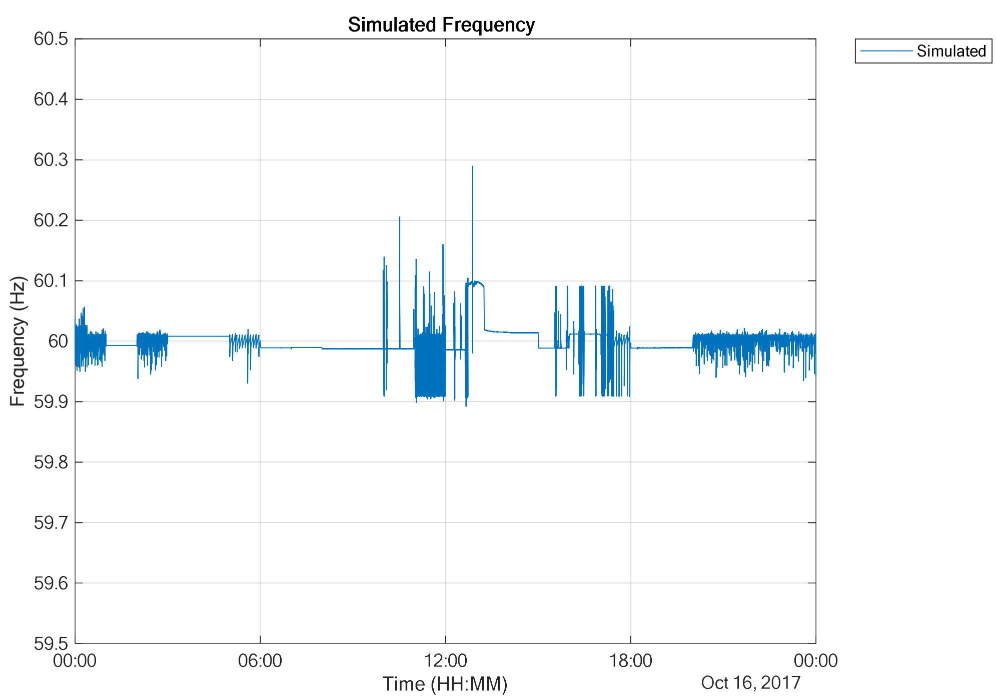


Figure 3-60 Simulated frequency for weekend when 2.5 MW / 13 MWh battery provides both primary frequency control and AGC with 4.3 MW of PV.



3.3.4 Base Case 4 & Simulation cases 19 – 24 Weekend with PV from 28 March 2016

Base Case 4: Weekday - Simulation of original PV with Tonga PV data from 28 March 16

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data. Figure 3-61 shows the simulation of generation unit outputs for a typical week day, with PV from Tonga on 28 March 16. This is the base case for these simulations where we can compare techno-economic impact of cases 19 to 24. The simulated frequency, as shown in Figure 3-62, shows the expected frequency variations without any frequency deviations from normal second to second changes in load.

Figure 3-61 Simulated generation on weekday with current installed PV

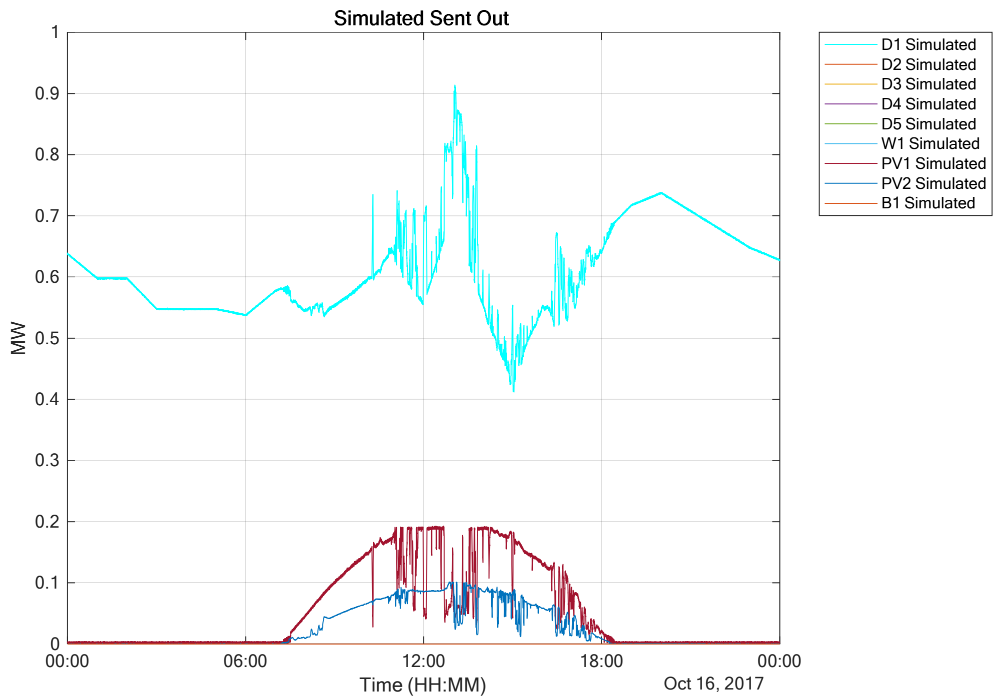
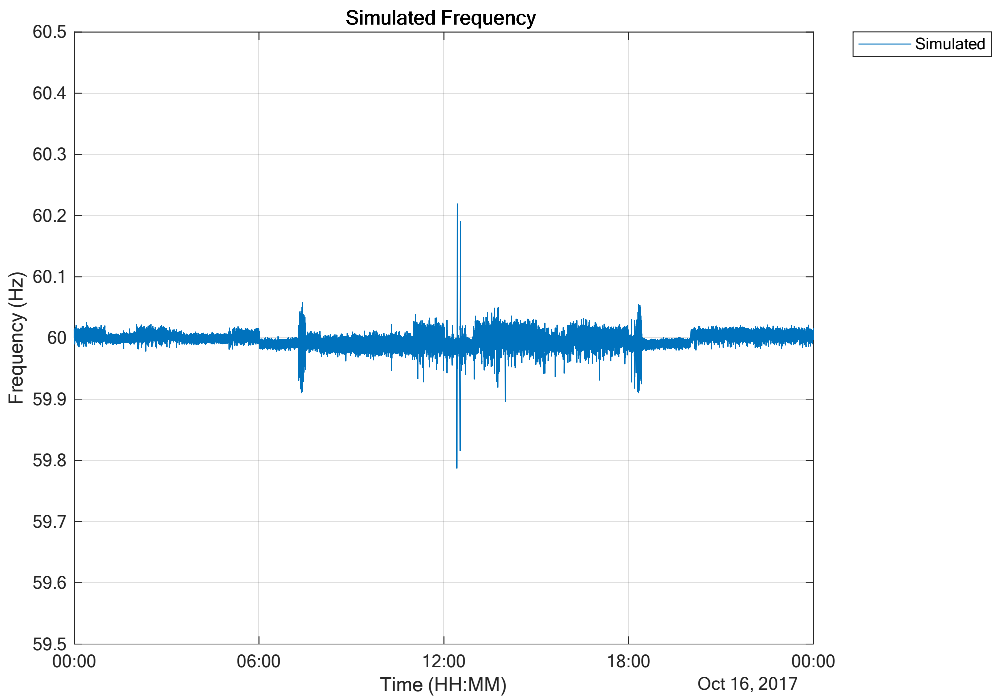


Figure 3-62 Simulated frequency on weekday with current installed PV



<u>Cases 19- 24: Weekday – Repeat of cases 1-8 with PV from 28 March 16.</u>

Cases 19 - 24 is the repeat of the simulations for a typical weekday but with a PV output from Tonga recorded on 28 March 16. The simulated frequency is within an acceptable range for case 19 with 1 MW total PV simulated and no batteries, as shown in Figure 3-63 but the simulated frequency control is worse with the more volatile PV variations. Case 20 with 1 MW of simulated PV with a 0.5 MW battery on primary frequency control results in an acceptable frequency control within acceptable limits of 59.5 to 60.5 Hz, as shown in

Figure 3-64. Case 21 with 2.3 MW of simulated PV with a 0.5 MW battery on primary frequency control results in an acceptable frequency control, as shown in Figure 3-65. Case 22 with the 2.3 MW of PV and 0.5 MW / 5 MWh battery on AGC has a very similar same result as for case 16. The same for Case 23 when the last diesel unit is allowed to off the battery has sufficient charge capacity to keep diesel off unit midnight.

Case 24 with 4.3 MW of PV and 2.5 MW / 13 MWh battery on AGC and all diesel off has similar results to case 18. Diesel units can be kept off the whole day and the excess PV is sufficient to fully charge the battery during the day, as shown in Figure 3-66. The surplus unused PV for this case is 10.6 MWh or 39.7 % of capacity available.

Table 3-5 Comparison of daily fuel saving and net savings for a weekday with different PV input data

Simulation description	Case 13 - 18 daily diesel fuel savings	Case 19 - 24 daily diesel fuel savings	Case 13 - 18 daily net savings	Case 19 - 24 daily net savings
1 MW PV battery off	853	906	486	444
1 MW PV 0.5 MW battery on gov	853	906	342	300
2.3 MW PV 0.5 MW battery on gov	1,147	1,057	-45	-355
2.3 MW PV 1.25 MW / 5 MWh battery on gov & AGC	2,126	2,102	289	46
2.3 MW PV 1.25 MW / 5 MWh battery on gov & AGC and Diesel allowed to go off	2,776	2,736	939	680
4.3 MW PV 2.5 MW / 13 MWh battery on gov & AGC and Diesel allowed to go off	4,044	4,048	27	-379

Figure 3-63 Case 19 - Simulated frequency on weekday with 1 MW PV

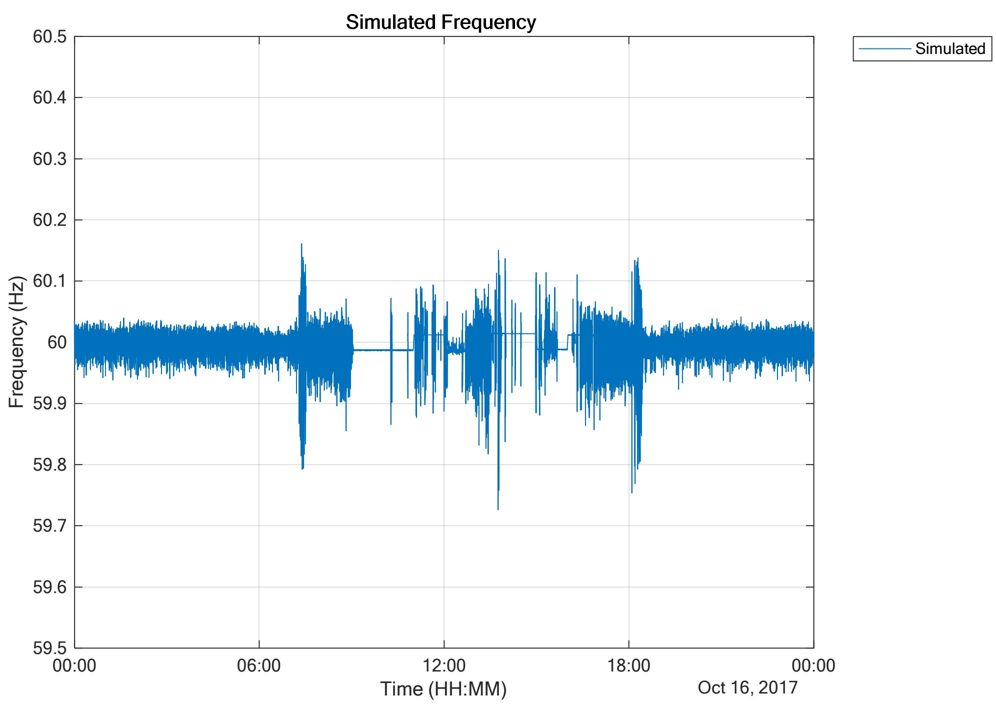


Figure 3-64 Case 20 - Simulated frequency on weekday with 1 MW PV and 0.5 MW battery on primary frequency control

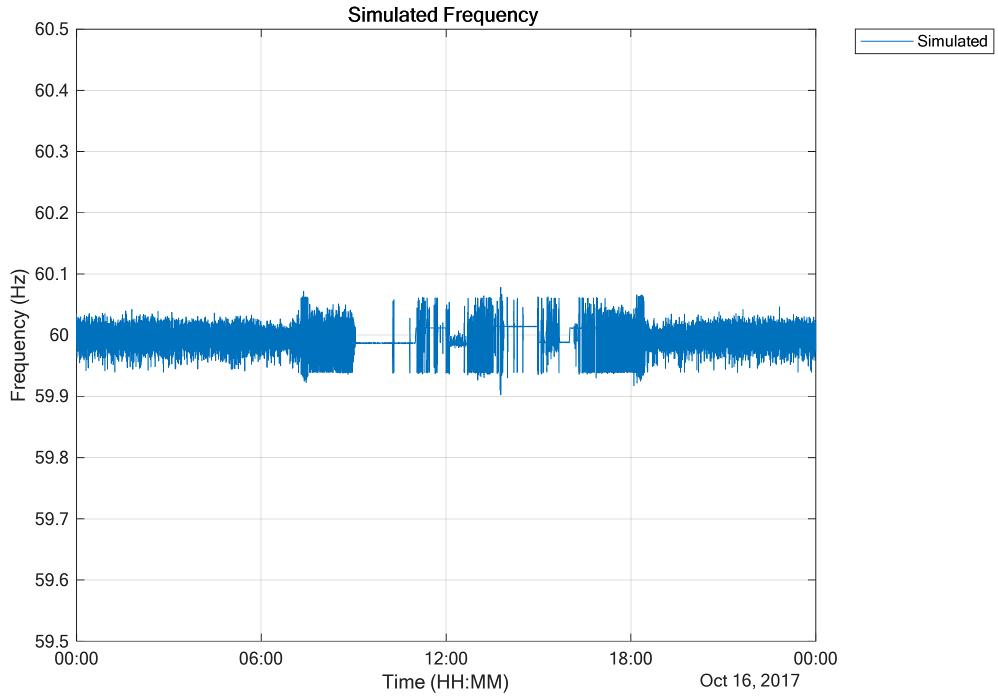


Figure 3-65 Case 21 - Simulated frequency on weekday with 2.3 MW PV and 0.5 MW battery on primary frequency control.

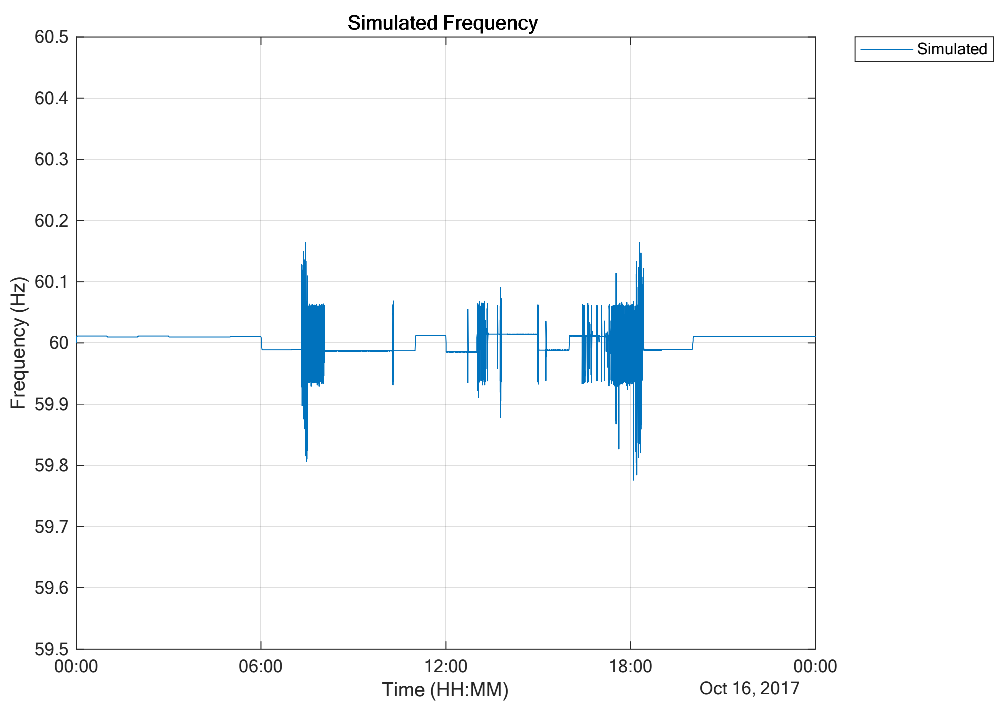
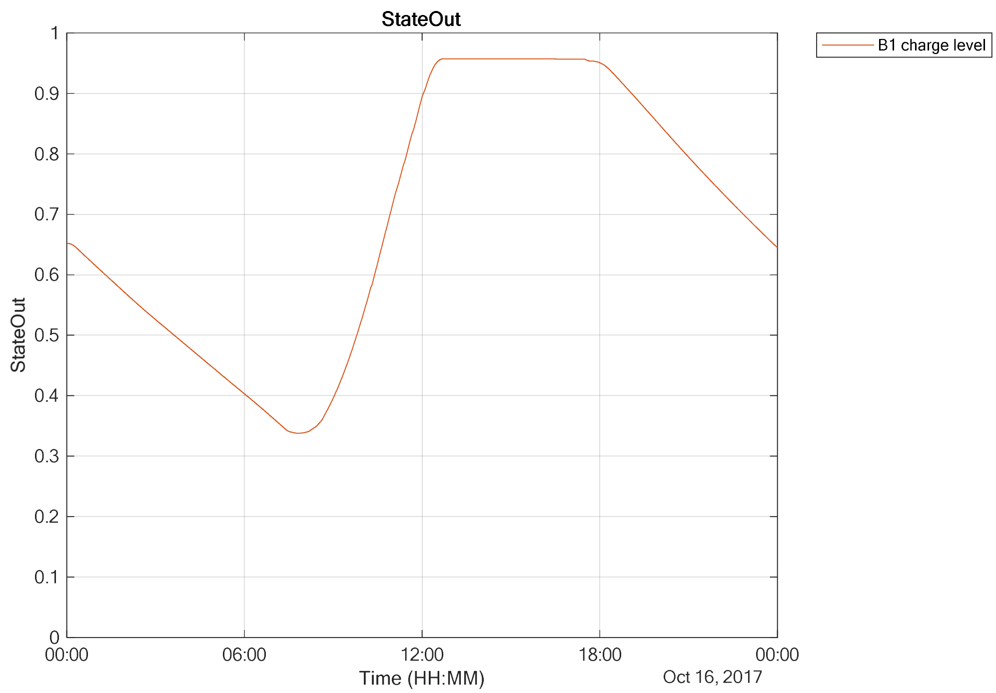


Figure 3-66 Case 32 - Simulated charge level on weekday with 4.3 MW of PV and 2.5 MW / 13 MWh battery on AGC and all diesel units off.



3.4 Financial Assessment of incorporating Storage

The simulations economic results are shown in

Table 3-6. The results are the calculated daily fuel consumed for the simulation case which is based on the fuel cost curve, as shown in Figure 3-11 and calculated every second. This is to obtain a reasonably accurate fuel calculation which depends directly on the instantaneous power the unit is producing.

The fuel percentage is the comparison of the base case for each day, which sets the benchmark for further studies.

The diesel power produced is to determine the average price per MWh. The PV power produced and the maximum that could have been produced shows if it was required to reduce the PV power output for frequency control. This is done as a last resort when the diesel or batteries cannot control frequency, the percentage reduction is an indication of the increased costs for the energy produced by the PV plants. Thus if the PV is reduced by 10% then the average price for PV is increased by the same percentage.

Table 3-6 Summary of economic results of simulations

No	Sim date	PV Installed (MW)	Diesel fuel costs	% fuel to sim base	Diesel MWh	PV MWh	PV max (MWh)	PV MWh reduced	% reduction	Comments
Base 1	weekend	0.3	3,598	100%	12.1	1.6	1.6	0.0	0.0%	Base case
1	weekend	1	3,111	86%	10.3	3.4	5.26	1.9	36.0%	No Batt
2	weekend	1	3,111	86%	10.3	3.4	5.26	1.9	36.0%	0.5 MW B1 on gov
3	weekend	2.3	2,989	83%	9.8	3.8	12.10	8.3	68.5%	0.5 MW B1 on gov
4	weekend	2.3	2,011	56%	6.5	7.6	12.10	4.5	37.5%	1.25 MW / 5 MWh B1 on AGC & gov
5	weekend	2.3	1,341	37%	4.5	9.5	12.10	2.6	21.7%	1.25 MW / 5 MWh B1 on AGC & gov – diesel off
6	weekend	4.3	107	3%	0.3	13.9	22.62	8.7	38.4%	2.5 MW / 13 MWh B1 on AGC & gov – diesel off
Base 2	weekend	0.3	3,524	100%	11.8	1.9	1.9	0.0	0.0%	Base case
7	weekend	1	3,135	89%	10.4	3.3	6.20	2.9	47.2%	No Batt
8	weekend	1	3,144	89%	10.4	3.3	6.20	2.9	47.2%	1.25 MW B1 on gov
9	weekend	2.3	3,016	86%	9.9	3.7	14.25	10.6	74.0%	1.25 MW B1 on gov
10	weekend	2.3	2,025	57%	6.5	7.5	14.25	6.8	47.7%	1.25 MW / 5 MWh B1 on AGC & gov
11	weekend	2.3	1,390	39%	4.7	9.4	14.25	4.8	34.0%	1.25 MW / 5 MWh B1 on AGC & gov – diesel off
12	weekend	4.3	103	3%	0.3	13.8	26.65	12.8	48.0%	2.5 MW / 13 MWh B1 on AGC & gov – diesel off
Base 3	weekday	0.3	4,153	126%	14.2	1.6	1.6	0.0	0.0%	Base case
13	weekday	1	3,300	100%	11.0	4.9	5.24	0.3	6.5%	No Batt
14	weekday	1	3,300	100%	11.0	4.9	5.24	0.3	6.5%	0.5 MW B1 on gov
15	weekday	2.3	3,006	91%	9.9	6.0	12.06	6.1	50.4%	0.5 MW B1 on gov
16	weekday	2.3	2,027	61%	6.6	9.7	12.06	2.3	19.3%	1.25 MW / 5 MWh B1 on AGC & gov
17	weekday	2.3	1,377	42%	4.5	11.7	12.06	0.4	3.1%	1.25 MW / 5 MWh B1 on AGC & gov – diesel off
18	weekday	4.3	109	3%	0.3	16.3	22.55	6.3	27.8%	2.5 MW / 13 MWh B1 on AGC & gov – diesel off
Base 4	weekday	0.3	4,079	124%	14.0	1.9	1.9	0.0	0.0%	Base case
19	weekday	1	3,247	98%	10.8	5.1	6.20	1.1	18.1%	No Batt
20	weekday	1	3,247	98%	10.8	5.1	6.20	1.1	18.0%	0.5 MW B1 on gov
21	weekday	2.3	3,096	94%	10.2	5.6	14.25	8.6	60.4%	0.5 MW B1 on gov
22	weekday	2.3	2,051	62%	6.6	9.6	14.25	4.6	32.4%	1.25 MW / 5 MWh B1 on AGC & gov
23	weekday	2.3	1,417	43%	4.8	11.5	14.25	2.7	19.3%	1.25 MW / 5 MWh B1 on AGC & gov – diesel off

24	weekday	4.3	105	3%	0.3	16.1	26.65	10.6	39.7%	2.5 MW / 13 MWh B1 on AGC & gov – diesel off

The simulations show that it is possible to increase the renewable energy penetration up to 2.3 MW with a 0.5 MW / 0.5 MWh battery without a negative impact on frequency control. To increase to further then a larger battery size is required.

Table 3-7 shows a summary of a few key cases in order to get an idea of how much saving is possible for including the annualised costs of PV and Battery. This is the summary is an average of the two PV simulation data sets used for cases.

The PV costs is estimated to be US$0.10 /kWh and the PV energy costs is calculated by the energy that could have been produced multiplied energy cost.

The technical ability to take off all diesel units needs further analysis but saves more than US$ 600 per day.

Table 3-7 Summary of a key cases and estimated costs and overall savings per day

No	PV MW	Diesel fuel costs	fuel savings	$/kwh	% fuel to base	Diesel MWh	PV MWh	PV max MWh	PV reduced	% reduction	Add. PV energy costs	Add. Battery cost	net saving
1 & 7	1	3,123	475	0.302	88 %	10.3	3.3	5.7	2.4	41.6%	415		60
3 & 9	2.3	3,003	595	0.304	84 %	9.9	3.8	13.2	9.4	71.3%	1,160	144	-708
4 & 10	2.3	2,018	1,580	0.310	57 %	6.5	7.5	13.2	5.7	42.6%	1,160	788	-368
6 & 11	2.3	1,366	2,232	0	0	5	9	13	4	0	1,160	788	284
7 & 12	4.3	105	3,493	0	0	0	14	25	11	0	2,305	1,920	-732
13 & 19	1	3,273	880	0.301	99 %	10.9	5.0	5.7	0.7	12.3%	415		465
15 & 21	2.3	3,051	1,102	0.303	92 %	10.1	5.8	13.2	7.3	55.4%	1,158	144	-200
16 & 22	2.3	2,039	2,114	0.309	62 %	6.6	9.7	13.2	3.5	25.8%	1,158	788	168
17 & 23	2.3	1,397	2,756	0.302	42 %	4.6	11.6	13.2	1.6	11.2%	1,158	788	810
18 & 24	4.3	107	4,046	0.317	3%	0.3	16.2	24.6	8.4	33.7%	2,302	1,920	-176

The simulations show that with 1 MW of PV power plants and no batteries will save US$ 60 for a weekend day and a simulated saving of US$465 for the week day. 2.3 MW of PV power plants and keeping 0.5 MW battery on primary frequency control gives an additional cost of US$ 708 for a weekend day and US$200 for the week day. The economic justification for only having batteries on primary frequency control is diminished to a loss as there is more than half the PV energy is not utilised.

Switching the last unit off during the day saving 0.45 MWh per hour will realise more savings US$ 600 a day but the practicality needs to be checked.

Annualising the savings from these simulations gives a rough estimate of the value of batteries from a security perspective alone and then from a 'less' secure perspective where the energy stored is utilised between 20 and 95% of battery capacity.

Annualising the solar costs, battery costs and fuel savings by simply taking the weekend results multiplied by 2 days and 52 weeks and the week day results multiplied by 5 days and 52 weeks gives a very rough estimate of the potential annual savings shown in Table 3-8.

Using the existing storage to its maximum by charging the batteries whenever there is surplus PV energy shows an estimated savings of US$ 240,053 per annum for a 1.25 MW / 5 MWh battery with 2.3 MW of installed PV and all diesel units allowed offline. This is the most optimal economic solution of the simulations performed. The batteries are not sufficient to run without diesel on a typical sunny day. The case of 4.3 MW of PV with 2.5 MW / 13 MWh of battery shows a loss for the simulated day but the simulation is performed without any demand growth and thus needs further studying as the demand increases.

Table 3-8 Estimated annualised solar and battery costs and fuel savings

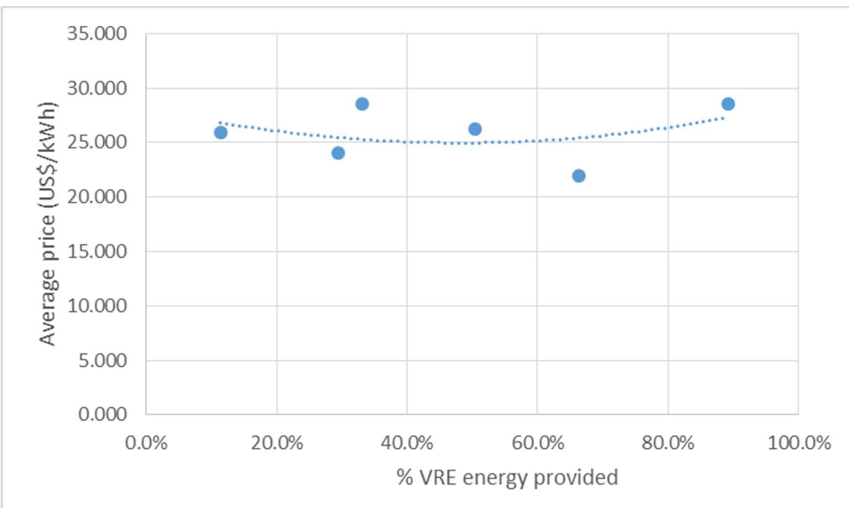
Description		PV Installed (MW)	% peak	Estimated diesel savings (pa)	Estimated additional PV costs (pa)	Estimated additional battery costs (pa)	Estimated nett saving (pa)
1 MW PV battery off		1	33%	278,107	150,985	0	127,121
2.3 MW PV 0.5 MW battery on gov		2.3	77%	348,408	421,769	52,312	-125,672
2.3 MW PV 1.25 MW / 5 MWh battery on gov & AGC		2.3	77%	714,010	421,769	286,903	5,338
2.3 MW PV 1.25 MW / 5 MWh battery on gov & AGC and Diesel allowed to go off		2.3	77%	948,724	421,769	286,903	240,053
4.3 MW PV 2.5 MW / 13 MWh battery on gov & AGC and Diesel allowed to go off		4.3	143%	1,415,256	838,358	698,705	-121,807

The ‘variable’ costs for a system is typically just the diesel cost divided by the energy produced by all power plants, which for the base case is estimated to be US$ 1,440,528 at an average 26 USc/ kWh. The total variable costs (including additional VRE and battery costs) decrease by 12 % when there is 2.3 MW of PV, 1.25 MW / 5 MWh battery and diesel are allowed off. The average ‘variable’ tariff drops to 22 USc/ kWh in this case. For the other cases the variable tariff is in the range 24 – 29 22 USc/ kWh.

Table 3-9 Estimated annualised solar and battery costs and fuel savings

Description	PV Installed (MW)	% peak	Total 'variable' costs	Average 'variable' costs USc/kWh	% decrease in total costs from base cases
1 MW PV battery off	1	33%	1,326,871	23.995	4.4%
2.3 MW PV 0.5 MW battery on gov	2.3	77%	1,579,665	28.594	-14.1%
2.3 MW PV 1.25 MW / 5 MWh battery on gov & AGC	2.3	77%	1,448,655	26.227	-4.6%
2.3 MW PV 1.25 MW / 5 MWh battery on gov & AGC and Diesel allowed to go off	2.3	77%	1,213,940	21.975	12.3%
4.3 MW PV 2.5 MW / 13 MWh battery on gov & AGC and Diesel allowed to go off	4.3	143%	1,575,800	28.534	-13.9%

Figure 3-67 Average variable tariff as VRE energy is added



3.5 . Tariff Impact Assessment

This section is examining the impact that the introduction or substitution of VRE has on current tariffs. The Pacific Power Association (PPA) published every year the Benchmarking Report which shows the Average Supply Costs for all member islands and the published tariff in the year. The following Table 3-10 gives a good indication of what the average supply costs (US Cents/kWh) were over the past years and the year on year fluctuations mainly due to fuel cost changes.

Table 3-10: Average Supply Costs (US Cents/kWh)[14]

		2012	2013	2014	2015	2016	2017	average
Tuvalu	TEC	96.60	85.66	n/a	91.91	67.22	48.61	**78.00**
Kosrae	KUA	50.40	54.42	61.54	50.67	44.94	48.85	**51.80**
Yap	YSPSC	56.20	56.91	57.79	46.48	n/a	53.08	**54.09**
Chuuk	CPUC	56.60	61.26	55.13	42.71	38.27	35.21	**48.20**
Pohnpei	PUC	50.80	48.13	n/a	35.32	n/a	28.75	**40.75**
Majuro	MEC	44.30	45.60	46.51	38.94	29.62	34.86	**39.97**
Tonga	TPL	40.30	38.91	44.00	99.28	84.47	64.70	**61.94**
Samoa	EPC	42.00	44.36	43.76	45.12	n/a	28.22	**40.69**

In many cases the average annual tariff is not covering these costs as is shown in the below table that compares the average supply costs versus tariff.

Table 3-11: Average Supply costs versus Tariffs for 2017 in US c/kwh[15]

		Average Supply Cost	Tariff
		2017	2017
Tuvalu	TEC	48.61	56.00
Kosrae	KUA	48.85	42.80
Yap	YSPSC	53.08	45.07
Chuuk	CPUC	35.21	47.13
Pohnpei	PUC	28.75	49.05
Majuro	MEC	34.86	34.60
Tonga	TPL	64.70	44.35
Samoa	EPC	28.22	42.15

Since the major cost component of the conventional power unit produced is that of fuel, the volatility in diesel prices has a major high-risk effect on the tariff. The tariff or levelized cost of electricity of solar PV and/or battery storage (in any combination) will reduce that risk drastically as the major cost is the capital cost which can be depreciated over time in a constant controllable manner. Further the studies and scenarios in the previous chapters have shown the optimal solution for each island and hence the impact assessment is looking at those and calculating the net effect on the tariff (2017) for all scenarios.

In the case of Kosrae, the following scenarios have been presented and as shown in the last column of Table 3-12, the option with 2.3MW PV 1.25MW/5Mwh battery on gov & AGC substituting all of the diesel generation would have the biggest impact on the variable costs. The total decrease in total variable costs from the base case scenario would be 12%. Variable costs meaning fuel costs plus annualised costs of PV and battery. This is used to estimate the incremental system cost in each case.

[14] PPA Benchmarking Report Fiscal year 2017 (published September 2018)

[15] PPA Benchmarking Report Fiscal year 2017 (published September 2018)

Table 3-12: Kosrae - Estimated annual total variable costs and percentage savings

Description	PV Installed (MW)	% peak	Total 'variable' costs	Average 'variable' costs USc/kWh	% decrease in total costs from base cases
1 MW PV battery off	1	33%	1,326,871	23.995	4%
2.3 MW PV 0.5 MW battery on gov	2.3	77%	1,579,665	28.594	-14%
2.3 MW PV 1.25 MW / 5 MWh battery on gov & AGC	2.3	77%	1,448,655	26.227	-5%
2.3 MW PV 1.25 MW / 5 MWh battery on gov & AGC and Diesel allowed to go off	2.3	77%	1,213,940	21.975	12%
4.3 MW PV 2.5 MW / 13 MWh battery on gov & AGC and Diesel allowed to go off	4.3	143%	1,575,800	28.534	-14%

The impact of the changes in variable costs for each scenario and the overall impact on a tariff (in 2017 terms) are illustrated below.

Table 3-13: Estimated Impact on Supply Costs and Tariff (in 2017 annualised figures)

Description	Total 'variable' costs	Average 'variable' costs USc/kWh	% decrease in total costs from base cases	2017 Supply Cost USc/kWh	Impact on Supply Cost	2017 Tariff Usc/kwh	Impact on Tariff
1 MW PV battery off	1,326,871	23.995	4%	48.85	47.89	42.80	41.84
2.3 MW PV 0.5 MW battery on gov	1,579,665	28.594	-14%	48.85	52.85	42.80	46.80
2.3 MW PV 1.25 MW / 5 MWh battery on gov & AGC	1,448,655	26.227	-5%	48.85	50.16	42.80	44.11
2.3 MW PV 1.25 MW / 5 MWh battery on gov & AGC and Diesel allowed to go off	1,213,940	21.975	12%	48.85	46.21	42.80	40.16
4.3 MW PV 2.5 MW / 13 MWh battery on gov & AGC and Diesel allowed to go off	1,575,800	28.534	-14%	48.85	52.84	42.80	46.79

The best-case scenario as described above would have a net impact on the tariff of more than US cents 2.5/kwh (from US cents 42.80/kwh to US cents 40.16/kwh). This is well below the average supply costs of US cents 51.80/kwh for the years 2012-2017.

3.6 Recommendations for application of storage

The studies show that 1 MW of PV can be installed without the need for batteries primary frequency control support. More than 1 MW of installed PV will require batteries for frequency control.

The secure strategy would be to install 1 MW of battery for primary frequency control once installed PV is more than 1 MW. The simulations show that 0.5 MW of battery is probably sufficient for 2 MW of installed PV but this strategy requires that all major PV plants can reduce their output from a centralised control system (AGC).

The most optimal economic solution of the simulations performed is 1.25 MW / 5 MWh battery with 2.3 MW of installed PV and all diesel units allowed offline giving an estimated savings of US$ 240,053.

The simulations show that installing 4.3 MW of PV with 2.5 MW / 13 MWh of battery with the current demand increases variable tariff by 14% but these studies would need to be repeated on the new demand and new PV / battery prices in a few years' time to determine the next optimal step.

4 Task 3: Supporting the Development or Revision of Grid Codes

Please refer to Appendix 1.

5 Task 4: Assessment of the needs for Supervisory control and data acquisition (SCADA) and Energy Management System (EMS)

5.1 Background: SCADA Systems

Supervisory Control and Data Acquisition (SCADA) is an Information Technology System which the main task is to communicate with remote elements, obtain information from them and import to a central control system with capacity to store, validate and monitor the values imported.

Main functions of the SCADA are:

1. Data Acquisition
2. Communications Management
3. Information Validation and conversion to engineering units
4. Alarm subsystem
5. Monitoring and trending
6. Supervisory Control

The values stored are used also by applications oriented to different aspects of the System.

In SCADA Systems used in electricity systems, complementary functions can be incorporated:

1. Generation Control Functions
2. Network Control
3. Quality assurance
4. System Economic Optimization
5. System Planning

Those aspects will be developed in the following points in the context of island distribution systems with conventional diesel generators, and Renewable Energy installations, including roof top installations.

5.2 SCADA Systems Basic activity

As indicated into the acronym of SCADA, **S**ystem **C**ontrol **a**nd **D**ata **A**cquisition, is the basic package which collects information from remote sources of information and validates it, monitors alarm violations, performs control actions, Communications Management and System Monitoring. In addition, it can have the capability to execute orders transmitted by the system, to the field.

5.2.1 Data Acquisition

Collect information from the field which could be of different types:

a. Analogue values like Voltage, Current or Power (active or reactive). Those values captured from the field in analogue ways are converted into digital in counts values (±0 – 2000), transmitted in digital format and, at reception are transformed to engineering values (Volts, Amperes…). Also, could be included in this type the number of a tap or the actual value of a meter.

b. Position or digital values like open/close, active/non-active… collected and send to the Control Centre as 0 or 1. Represents either the status of a breaker or an isolator or an alarm activated or not.

c. Values of meters or similar, presented in a higher precision than a normal Analogue value.

That information, collected in the field, uses a Remote Terminal Unit (RTU) which concentrates the information, prepare it to communicate and transfer it to the control center when requested to do it.

This communication is requested by the Control Center, normally on timely basis (scan). In case of alarms, the RTU may initiate the communication with the Control Center, requesting to stablish a communication and to be interrogated.

Size and capacity of RTU's can be adjusted to the needs, from a simple RTU to collect one value to RTU's to collect and operated a big substation, using in each case the appropriate technology. Even the use of Programmable Logic Controller (PLC[16]) has been used in small systems.

5.2.2 Communications

The Communications between the Control Centre and the RTU's are supported by any available WAN technologies (Wide Area Communication) and several applications protocols.

Communications technologies used for transmission of big amount of information in wide area can be based on wired or wireless solutions. The wired solution vary from Fiber-Optic and xDSL communication , to simple PLC (Power Line Carrier). The wireless technologies can be based on Cellular data communication technologies (2G: GSM, GPRS / 3G:UMTS, HSPA / 4G:LTE) or other Radio solutions such as WiMAX or Coupling.

Depending on the size of information and the frequency required to transmit it, and considering the acceptable delay, the best option could be one or the other.

The operation of the SCADA system is dependent on reliable communication from each station to the central control station. International best practice recommends that Power Utilities establish their own communication network and not be dependent on public Telecommunication operators. A Telco's objective is different to earn revenue from selling bandwidth, whereas a Power Utility has to ensure the reliability of the power network. We therefor recommend that a utility owned Telecommunication network be established to provide the communications required for the Control system.

The protocols used can be divided in four main groups:

a. For many years the SCADA suppliers have imposed proprietary protocols, used exclusively in their own installations. This situation creates a dependency between the supplier of the RTU's that should be the same (or compatible) with the SCADA system if you want to avoid that an RTU supplier shall emulate the SCADA protocol with the information provided by the supplier. This situation is changing but some of those protocols are still in service due to extended usable life of RTU's.

b. Some general-purpose protocols like Modbus or DNP (Distributed Network Protocol) are quite efficient for use in the Electricity Networks control, at different levels. Despite the age of these protocols, they are still in use (Modbus was created at the end of 70's), with good results.

c. Special protocols are designed by international standardization bodies such as IEC (International Electrotechnical Commission), specifically for Electricity Systems applications such as the IEC 60870 series of standards. The IEC 60870-5-101 and 104 protocols provide serial and IP connectivity, respectively, between the IEDs and RTUs in the substations or generation plants with the control center. The IEC 60870-6, also known as TASE protocol, provide communication between the control centers. The advantage of these application protocols is interoperability, that allows multi-vendor option for systems and elements.

d. The Internet Protocol (IP) is the principal communications protocol used in the Internet, using source and destination addresses. Its routing function enables internetworking and is useful for connection between RTU's in the Field and with the Control Centre

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16 PLC acronym is used also as Power Line Carrier, a communication technology that uses the electric wires as communications carrier.

All those protocols could be used, but some precautions need to be taken, especially in communications security.

5.2.3 Information validation

The analogue information (± 0 – 1 mA as example) is converted and sent to the control centre in counts ± 0 – 2000 (for example, 0 ma = 0 counts and 1 mA 1.900 counts). The first activity in the Control Centre is convert the counts into engineering units, computing the parameters of the conversions. Normally a part of the available area/capacity is dedicated to overflow detection.

When the information arrives to the Control Centre, the first activity is to validate the value received. To determine if the value received is correct, it must be inside the expected limits and the variation between two or three consecutive values must be coherent with the potential variation of the element measured. Those checks are done to all values received and alarmed. Any measure can have various sets of limits, but usually two are used: Pre-alarm and alarm.

Those alarms are registered and presented to the operator.

5.2.4 Alarms subsystem

The alarms become one simplified way to alert operators to some irregularities in the system. This helps to the operator to concentrate in those messages.

The problem arises when the number of simultaneous alarms becomes too high. A low voltage generalized situation, will generate an alarm for each voltage measured point and each time that goes in or out of any limit.

Some systems use Alarms Intelligent Processors (AIP) or Intelligent Observation Systems (IOS) that study, concentrate and resume as much as possible the alarms to be presented to the operator. This recent functionality still in their infancy and will require some more development, but even under those circumstances still a useful tool.

Alarm messages are time stamped, in some systems with the time of arrival to the Control Centre, without precision, in others time is stamped by the RTU, with a precision of few milliseconds. This last functionality is known as “Sequence of Events” because it allows to establish in the control centre the real sequence of events that took place in the system, allowing better compression of the incident and the capability to take more adequate decisions.

Alarms are stored in a file ordered by time, for later study.

Operators are requested to recognize an alarm when they see it (to cancel audible alarms and stop blinking screens or indicators) and delete them from the active alarms list when solved.

The historical of alarms cannot be deleted.

5.2.5 Monitoring and trending

The SCADA stores the values in its data bases in two different ways:

a. Contains the last values received from the field. Could be considered an image of the network in a certain time and under known conditions. This image of the system can be saved, manually or automatically for subsequent studies, of this situation or as representative of some similar network conditions in the future.

b. Selected values could be individually monitored, so in a particular Data Base each selected value received from this source or calculated with digital and/or received values, is saved on a dedicated Data Base and presented as a tabular or as a graphic trend.

Data Bases can be presented to the operator in form of tabular or full graphic. Tabular presentation presents more precise individual values while graphical information provides a better global view of the current system conditions. Both are alternative ways to present the same information.

Ref: REE (www.ree.es)

5.2.6 Supervisory Control

SCADA not only allows collection of a range of information and make it available in the Control Centre, but also allows transmission of instructions to the RTU that will be precisely executed on the field.

Those orders are typically:

- Open/Close isolators and breakers
- Connect/disconnect elements such as shunt devices or batteries
- Raise/Lower the tap changers in transformers when permission is received
- Establish and modify setting points in Reactive power generation or transformers voltage control
- Establish or modify generation set points
- Voltage control, by modifying the reactive power generation set point.

All those potential actions will allow and efficient control of the network conditions.

5.2.7 Resume of Basic Functionality

The functions described in the points above constitute the SCADA – Basic Functionality. All SCADA Systems shall be capable to perform those activities that can be found to control large and small generating units from the Control Room.

Differences between large and small systems are in the system size, number of points controlled, the capacity of the IT System, number of RTU's, or the functionality of the specific applications.

5.3 Added applications

The contribution of the SCADA to control electricity systems, starting with transmission systems, started being commercially available and in the late 60's and early 70's, for the electricity system control becoming very soon in the most efficient control tool to improve system information and control and, at the same time, reduce operative costs.

For that reason and around the SCADA a big set of applications has been developed being today the master stone of an efficient and safe control system.

Some of the top functionalities are listed below, grouped considering their main objectives, that will facilitate, not only the understanding of their use but also in order to show possible options.

5.4 EMS versus DMS

There are two main suites of external applications that group the main functionalities design, according to different objectives of the network to be controlled like generators control, transmission systems or distribution systems:

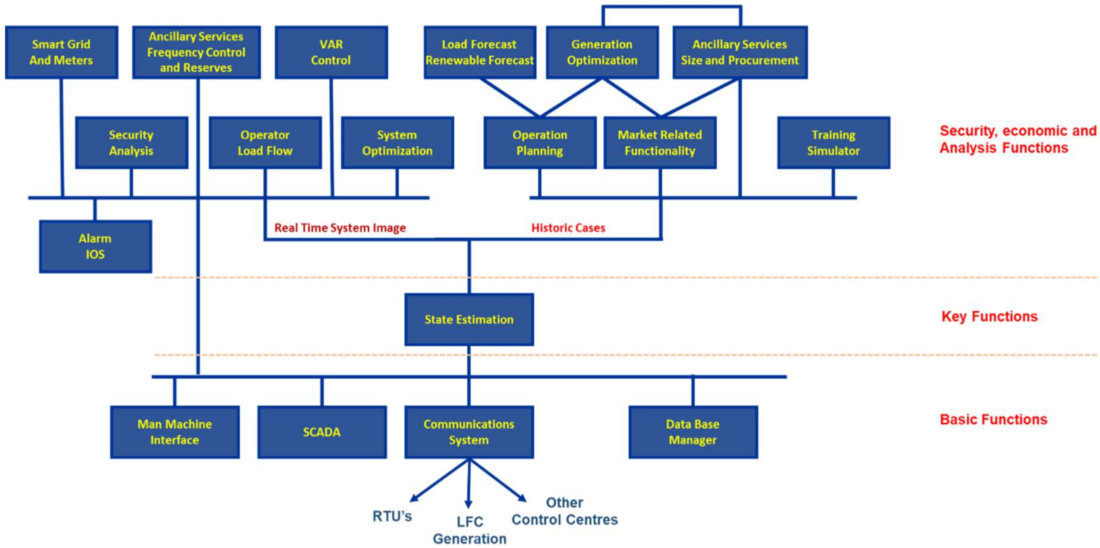
a. **Energy Management System (EMS)** oriented to generation and transmission systems. The main characteristics of those systems are those that are the relatively big size in generation and load, small or medium number of substations and extra high number of controlled elements, with the system fully meshed, operated with almost all breakers closed.

b. **Distribution Management Systems (DMS)** oriented to distribution systems operated radially, without forming loops in the system, with a high number of stations controlling a small number of elements on each station. Operation must be done by opening and closing elements of the network, in most cases passing thorough zero voltage.

The Kosrae power network consisting of 13.8kV, 4.16kV and LV networks resembles more a Distribution network than a Transmission network. The deployment of the Control System therefore requires consideration of DMS rather than EMS functions.

5.4.1 EMS System

The added EMS functionalities are supported by the SCADA System and the information obtained from the field. The following picture represents the different functions normally presented in schematic way, an EMS System functionality.



Briefly, the following applications are oriented to:

5.4.1.1 State Estimation

Normally values are measured with a certain level of error introduced by measurement or when transformed from analogue to digital format. It is acceptable that, in the best of cases, the error will be around 1,0 %. This means than any value in the system, as example a Voltage at 220 kV, the value send to Control Centre is 220 kV, but the real value could be any value between 198 and 222 kV. Same error or higher is expected with flows and current readings.

This situation is unavoidable and means that the image of the system will have some distortion in the values received, while, at the same time, some other values may be lost or not available.

If under these conditions, the operator tries to perform any study (load flow or contingency analysis) the results, if any solution is reached, may include some deviations that make the values with a low accuracy and even useless.

State Estimator tries to solve those incoherencies and obtain the best possible image with the values received and the multiples redundancies available in the system. This will generate an equation system with more equations than variables, solved normally by Newton – Raphson iterative process, to find a set of values, using a minimum quadratic deviation, coherent among them.

The result is the most probable coherent set of values.

The system takes care to weigh automatically the values regarding the proximity between the received and calculated values.

This is calculated over the electric model of the network, formed not only by all generators and loads in the system, but also with a mathematical representation of the network, which may introduce errors in the calculated values of impedance or resistance of any equipment in the network, including lines, transformers, shunt devices or loads, active and reactive. Any mistake in those values will automatically reduce the results accuracy or prevent to the application to reach a solution.

This function is very complex to fine tuning and in to many cases the results does not reach a minimum required accuracy.

5.4.1.2 Load Flow

Once the State estimator is well tuned and available, then using its solution as input, it is possible to run the Load Flow, which taking as input the network model and the generation and load in each node, calculates the in real voltages and flows on each node or network element at real time or in study mode. In top of this, and using the solution as a Base Case, the Load Flow will simulate any new situation (modify generation or load profiles or the network topology, presenting as input, the modified loads, generations and topology, the Load Flow will present as output the system conditions after the simulation (Voltages and Flows).

5.4.1.3 Optimal Load Flow.

In this case, the inputs are the same but, in addition the results will show the optimal values for some control elements values like reactive generation, shunt devices or tap changes, that can be proposed to change, after evaluation with a cost for any control change, that simulates the priority. System losses will have also a cost. The control function to be minimized will display the cost optimal set of values of control elements: maximum losses reduction with a minimum cost. The use of different costs for each action, will reflect the system control priorities.

5.4.1.4 Ancillary Services requirements

Two of the most important aspects for system security: Different Types of Reserves for Frequency Control and capacity to Voltage Control are the main ones:

a. **The Load Frequency Control (LFC)**, is the application in the system that controls directly the governors of the dedicated generating units and in an automated close loop, increases or reduces the actual generation to maintain the frequency stability. The final action of the LFC, send the raise/lower or fix a set point, is also known as Automated Generation Control (AGC)
b. **Voltage control**, especially with the appearance of Renewable Generation parks, and its limited participation in the voltage control, compared with the conventional units (combined cycle gas units as example), has become one of the major quality issues problems. The intensive use of all tools available today like shunt devices, VAR systems or even SVC and STATCOM units are frequently found for voltage control

5.4.1.5 Security Analysis

It is the suite of applications oriented to verify that the Security Criteria are fulfilled any time, during operation planning or in Real Time. Perhaps the most known application is the Contingency Analysis (CA), where all the conditions included in the security criteria are tested during operation planning and in Real Time.

This suite of functions are basic to determine the capability of the system to survive to any contingency included in the Security Criteria stablished in the Grid Codes or in the Regulation laws.

5.4.1.6 Forecast Applications

Load demand forecast and Renewable Generation forecasts applications, normally at park level, for wind and solar generation.

Forecast is done at long term level for planning considerations and at next year level to guarantee the availability of resources, at infrastructure level.

At medium term or few months to plan maintenance of generation units and network elements or verify the availability of generation to supply the energy that will be demanded by all clients.

At day ahead, to operation planning including security constrains and in Real Time for security analysis at few minutes to few hours in advance.

5.4.1.7 Generation schedule

Taking the load and RE forecasts as inputs, the generation schedule is now possible, where the generation needs will be anticipated for the day ahead or in Real Time for the near future.

In addition to verify the needs of generation also controls the availability on the system of the different types of reserves, according with the security constrains.

5.4.1.8 Generation Control

It is a highly complex activity and requires specific tools. Most of the information is collected by SCADA Systems (one or more) and addressed to a Control Room, where the different parts of the power plant/unit are monitored or controlled by operators. Some actions launched are executed in automated mode.

This control philosophy is extended to most large power plants from Nuclear Plants to Coal, Gas or hydro units. It is not a simple application. To control a unit or a power plant requires a group of applications that in a coordinated mode facilitate to operators the plant control, from the high voltage park to any kind of fuel supply.

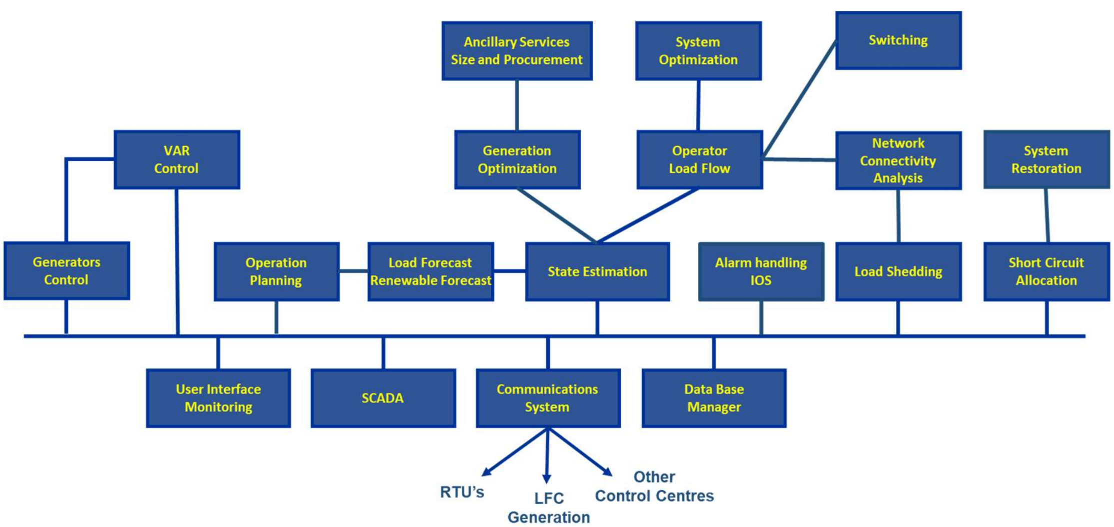
Ref: https://www.winsted.com/resources/case-studies/university-virginia/

Those applications facilitate that today many generating units are controlled from a centre located outside of the plant itself, reducing considerably the operation costs.

5.4.2 DMS System

The Distribution Management System is more oriented to distribution networks management. For networks operated as radial, the applications are completely different to the case of meshed networks.

Functionality of applications are similar than in case of EMS but the methodology and mathematical approach are quite different.

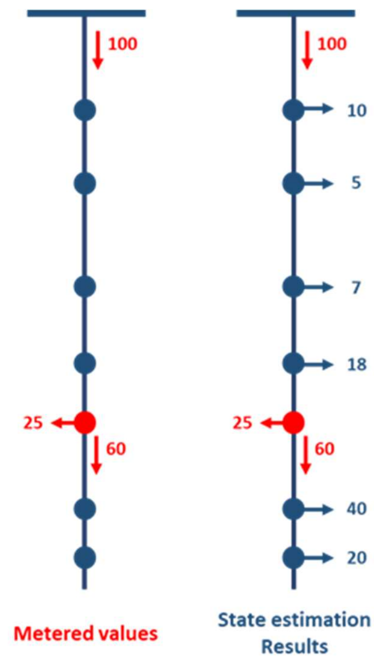


The main applications are:

5.4.2.1 State Estimation (SE).

The state estimator is an integral part of the overall monitoring and control systems for transmission networks. It is mainly aimed at providing a reliable estimate of the system values. State estimators allow the calculation of these variables of interest with high confidence despite the facts that the measurements may be corrupted by noise or could be missing or inaccurate.

Even though we may not be able to directly observe the state, it can be inferred from a scan of measurements which are assumed to be synchronized. The system appears to be progressing through a sequence of static states that are driven by various parameters like changes in load profile. The outputs of the state estimator can be given to various applications like Load Flow Analysis, Contingency Analysis, and other applications.

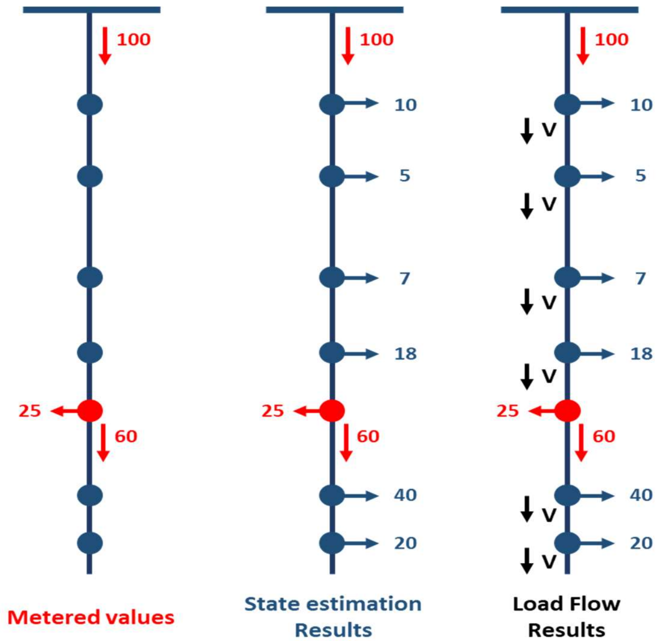


5.4.2.2 Load Flow Applications (LFA).

The Load Flow study is an important tool involving numerical analysis applied to a power system. The load flow study usually uses simplified notations like a single-line diagram and focuses on various forms of AC power rather than voltage and current. It analyses the power systems in normal steady-state operation. The goal of a power flow study is to obtain complete voltage angle and magnitude information for each bus in a power system for specified load and generator real power and voltage conditions. Once this information is known, active and reactive power flow on each branch as well as generator reactive power output will be analytically determined.

Due to the nonlinear nature of this problem, numerical methods are employed to obtain a solution that is within an acceptable tolerance. The load model needs to automatically calculate loads to match telemetered or forecasted feeder currents. It utilises customer type, load profiles and other information to properly distribute the load to each individual distribution transformer. Load-flow or Power flow studies are important for planning future expansion of power systems as well as in determining the best operation of existing

For a better understanding of the combined use of those two application the following schemes represent a feeder with only the metered information, the second one after the State Estimation, (that used load profiles, number of clients…) which estimates the load in the transformer stations without this information and the third after running and Load Flow, which calculate all flows and voltages. The estimated values will probably to some extent modified by the load flow due the results of losses calculation in each feeder section. The accuracy of the results will be a function of the accuracy of the State Estimator.



5.4.2.3 Generation Control.

A generator embedded in the Distribution networks is normally of power capacity compatible with the feeder where it is allocated. This makes that groups will be significantly smaller than units connected into the transmission grid. Groups will be easy to operate and at the same time supporting network security and the frequency and voltage maintenance. Big control panels filled with push buttons and analogic measures in the past, have been substituted by digital systems that provide in a screen much better capacity to operate the generator and monitor its values.

This application is normally developed by each supplier for their own supplied generators. This control application always runs in top of a SCADA System and the generation control is limited in most cases to the generator from the same supplier. For that reason, in some cases we found two SCADA systems dedicated to control generators from different suppliers.

As reviewed within EMS functionalities earlier, the Load Frequency Control (LFC) and Automated Generation Control (AGC) are part of the EMS system. Normal operation for an electricity system is that frequency is controlled in high voltage systems using SCADA + LFC/AGC modules, and in that case, there is no need to maintain the frequency in the distribution side.

In the isolated systems, normally there is only one system controlled from a single Control Centre. In

that case, all functionality shall be included in the Control Centre and under the SCADA System.

In general, there are two common ways to control frequency:

- ✓ Manually: The Control Centre or the Generation Operator controls the frequency by transferring instructions directly to generators or to operators to manually increase or reduce generation. This control system gives a pour quality on frequency control. This methodology is used in some isolated systems (such as UK, India…).

- ✓ Automated: The Computer controls the deviation of the frequency, generating the raise / lower signals to the generators control elements to maintain the frequency precisely to set point. Even some dispatch's take the responsibility to control the hour deviation and set the frequency monthly to correct the "electric hour" (Laufenburg). This control method produces a very precise frequency control but is much more expensive to implement. This is the common control methodology used across Europe and USA… Its main advantage is to allow fair interchanges.

It is also true that the basic capacity of any SCADA to collect information and presented to the operator facilitates the monitoring and control of some additional points (breakers, transformers…).

5.4.2.4 Network Connectivity Analysis (NCA)

By analysing the network information obtained thorough the SCADA System, NCA considers the position of all switching elements and assists to the operator to know operating state of the distribution network indicating radial mode, loops and parallels in the network.

5.4.2.5 Switching Schedule & Safety Management.

Control engineers prepare switching schedules to isolate and make safe a section of network before work is carried out, and the DMS validates these schedules using its network model. When the required section has been made safe, the DMS allows a Permit To Work (PTW) document to be issued. After its cancellation when the work has been finished, the switching schedule then facilitates restoration of the normal running arrangements.

5.4.2.6 Voltage Control

Is responsible for the control of voltage in the system, using:

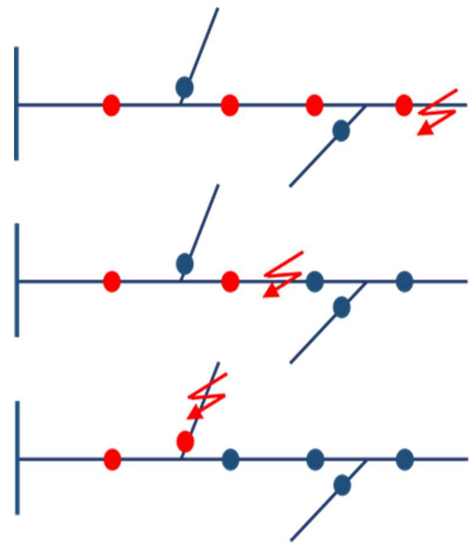
- ✓ Reactive power generation or absorption in generators (VAR control)
- ✓ Modifying the transformer's ratio, changing in cold or in hot. In this last case, also known as Load Tap Changing, where the transformer is in service, the number of changes per day is normally limited.
- ✓ There are also autotransformers that has a rate very close to 1,00 which means that the voltage variation is small and are used only for voltage control in the same voltage level.
- ✓ Use of external control elements like shunt devices (batteries or reactors) or advanced voltage controllers like SVC's or STATCOM's

Most of those elements can be used in automated way, controlling the voltage in the connection point. In some cases, the objective voltage is a function of the nominal voltage and current load.

5.4.2.7 Short Circuit Allocation.

Unexpected and undesired short circuits in the network are a reality that cannot be avoided but could be reduced with good maintenance that will improve the system reliability. The impact of a short circuit and its impact into the Quality of Service can be limited by detecting the portion of the network where the short circuit took place, so restoration can start faster.

Short circuit allocation is based in the use of short circuit current elements in the network that simply detects its pass and communicate the detection to the Control Centre. The following graphic shows its application to determine the short circuit allocation.



The blue dots represent the locations with a short circuit pass detector and the red the ones that elements that detected the pass of the current.

For each location of the short circuit in the network (feeder) there is a different configuration of elements which detected the pass of the short circuit current and in consequence the short circuit location itself which will allow to the operator to start actions to restore the system immediately.

The detectors shall be capable to communicate with the centre by themselves (using a PLC or GRPS communication, as example) or incorporating the signal into an RTU that collects other types of information.

5.4.2.8 Load Shedding Application (LSA)

One of the key aspects in an electric system control is maintain the equilibrium between Load and Generation. Operation Planning (day ahead) or real time adjustments are meant to control the generation to supply the demand.

But in cases of extraordinary demand or generation trip, this balance is lost. The system reacts modifying the system frequency that must be corrected increasing (or reducing) the generation in other units. The problem becomes more critical when the generation margins have been exhausted. In this case, the only solution is to reduce the load, known as load shedding.

This reduction or Load Shedding can be done manually or automated using a Load Shedding Application (LSA).

The most common method is to reject some load when the frequency reaches some values, with the double objective to protect the generators and to stabilize the network, which makes the restoration easy and faster.

Normally the “trigger” is a protection that reads the frequency or the frequency drop speed, anticipating the frequency lower values and reacts tripping some feeders to achieve the load reduction. In a system normally there are few levels of frequency to reduce the load (between 3 and 5) and at each frequency level a certain amount of load is rejected (from 15% to 25%).

5.4.2.9 Fault Management & System Restoration (FMSR).

Incidents in the network are, by its own nature, impossible to avoid or reduce. Number of landed thunderbolts or number of storms in a year, are impossible to reduce but, the quality of service will be improved if the extension is reduced and the restoration is faster.

Those applications tend to reduce the restoration time by automating part of the restoration process. This functionality requires an excellent electric model and intensive information compilation. Is especially useful for those utilities that have by law, for safety purposes, limited the time to test lines or cables (some countries have this limitation in 1 minute) and, after this elapsed time, to test a cable requires the presence of operators on location, to verify there is no danger for the public during the test.

The FMSR is also useful for big distribution networks with a large number of potential restoration paths.

5.4.2.10 Distribution Load Forecasting (DLF)

As said above, one of the main aspects to consider is the balance between generation and load. System load includes the client’s consumption and the system technical and nontechnical losses. This is an information which is not known on operation planning or even in the immediate future on Real Time. Also, the Non-dispatchable generation (in general renewable or auto-generation) is not known in advance.

The main objective is to schedule the conventional dispatchable generation, in advance, which will allow to apply generation optimization processes and program maintenance preventive and corrective works.

The traditional energy balance equation is:

$$CG + RE + IB = LO + SL$$

Where: CG is the Conventional Dispatchable Generation

LO is the total Load (Estimated)

IBs are the interchanges balance (operation decision). Not applicable in isolated systems.

SL are the System Losses (Technical + Non-Technical)

RE is the Renewable Generation (Forecasted with error)

ERE is the Embedded Renewable Generation (Estimated)

The same balance equation could be written as:

$$DG = \underbrace{(LO + SL)}_{\text{Estimated together}} - \underbrace{RE}_{\text{Estimated Individually}}$$

So to consider the schedule of conventional dispatchable generation, there is a need to perform two separated operations:

- ✓ Load + Losses forecast, this will require a cleaned historic load data base.
- ✓ Renewable or non-dispatchable generation, which could be estimated global in the island or park by park, independently if it is solar or wind parks.

Those forecasts shall be calculated for at least two different time horizons:

- ✓ Day (or week ahead) for operation planning.
- ✓ Minutes or hours ahead for real time security analysis performance calculation.

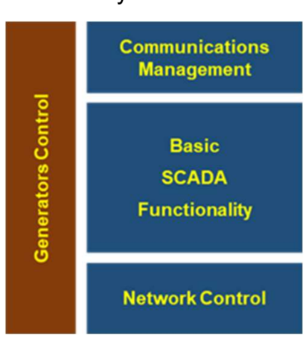
5.4.2.11 Load Balancing via Feeder Reconfiguration (LBFR)

Consist on automate the decision process to decide the network configuration from the network topology, deciding the status of all embedded isolators or breakers (open or close) which for big systems may represent thousands of different configurations. The application will consider which one is the optimal one.

5.4.3 Requirements of the Distributions Systems

In the Distribution Systems like the one in KOSRAE or as seen in the other islands, 3 requirements are identified:

- Network Control and Monitoring
- Quality assurance
- System Economic Optimization



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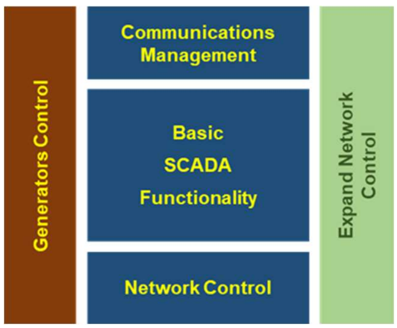
5.4.3.1 Network Control and Monitoring

- SCADA Systems normally provide enough capacity for system monitoring and control.
- User interface should be simple and capable to show the network at different details level depending on the real-time requirements.
- Zoom, Panning and Clustering shall be available in the system.
- The capacity to supervisory control shall be protected in a two steps operation (i.e. selection and execution)

Capacity to control a wall system will be appreciated



5.4.3.2 Quality Assurance

Quality of service is essential for any distribution system. This could be considered under two aspects, with the same level of rank.

1. Service Continuity: Consisting in the maintenance of the service under different situations and circumstances.

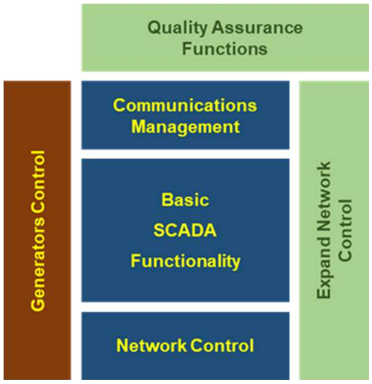
   The main problem to face for continuity of service is the external incidents into the network, such as; lightning, storms, high speed winds, car accidents, vegetation… There are only limited ways to avoid the existence of those incidents, but they can be mitigated using more secure network elements.

   If the incident cannot be avoided, then, to improve the quality and reduce the time with blackout, the efforts shall be put to reduce the restoration time and the extension of the blackout.

2. Quality of the supply: considering as the main parameters the frequency, voltage, harmonics…

There are not external factors that impact into those quality aspects. Operation planning, normally for the day ahead, is the operation time where those aspects shall be considered and the resources existing made available for operation

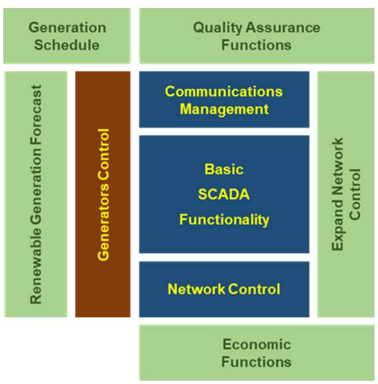
Some applications to control those aspects, together with the Reserves size and allocation, which do not directly impact into quality, but in case of other incidents, will help to limit the extent and magnitude of the incident and eventually reduce the restoration time.



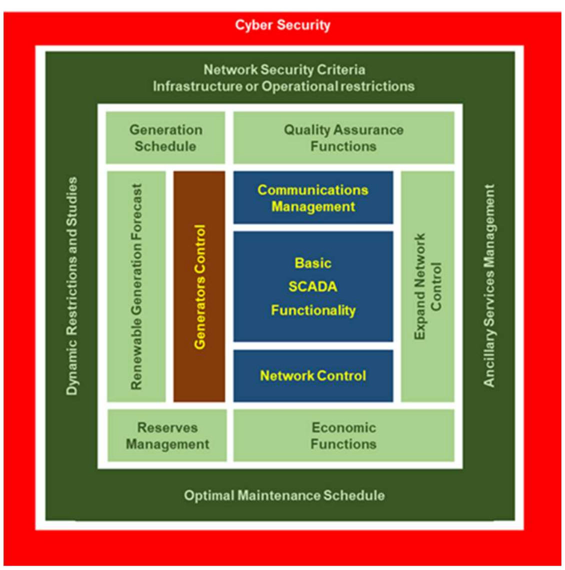
5.4.3.3 System Economic Optimization

Economy is one of the aspects that comes immediately after the quality and service assurance.

When talking about economy in the network operation and considering that generation scheduling is already optimized, the main aspect is loss reduction. The SCADA application should provide the tools to control the network losses: Optimal switching in the network and feeder loss reduction…



Once this status will be fulfilled, after later considerations and integrations, the system can reach a final status. Some of those functionalities could be anticipated.



5.4.4 Recommendation between EMS and DMS

Both are highly powerful tools, but considering:

- The operation of the systems are radial and not meshed
- The size and low complexity of the networks
- The requirements and constrains of the Distribution Systems
- The priorities expressed by the Distribution Utilities

Our recommendation is look for a tailored Distribution Management System (DMS) instead of adapting an EMS to Island systems.

In our opinion and understanding, there are too many functionalities and operation changes to be introduced at the same time, so we propose to divide the functions in coherent groups and introduce them into ordinary operation in two or three steps.

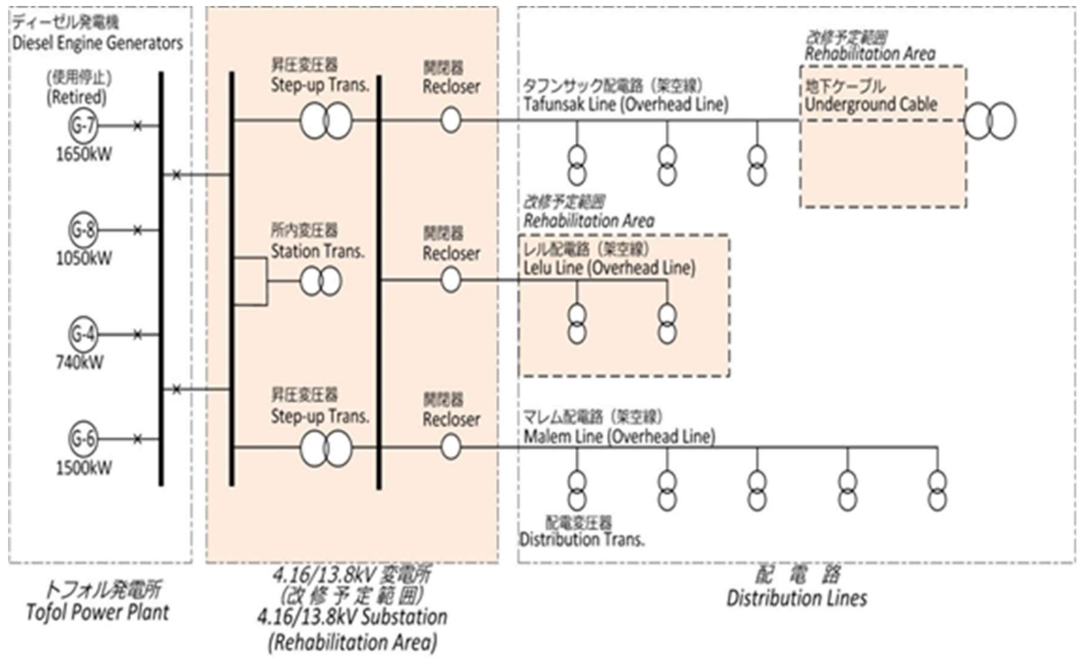
5.5 Kosrae Utilities Authority

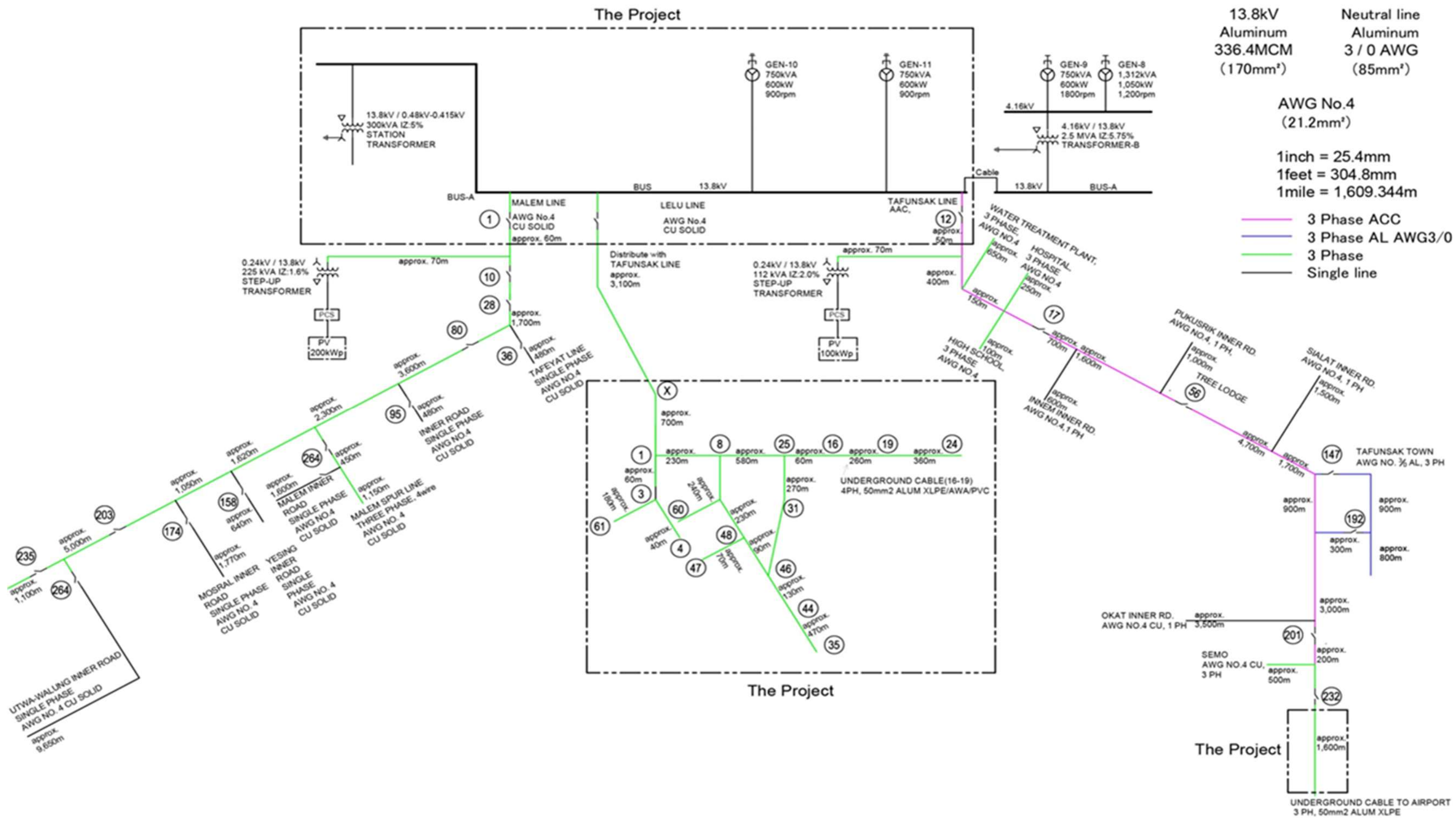
5.5.1 Network and available Operation Systems

The salient points of the electricity system in KOSRAE can be summarised in the following data:

Concept	Value	Unit
Peak Load	1.000	kw
Energy generated per year	5.542	Mwh
Available Generators Conventional	3	
Generators Renewable	7	
Conventional Installed power	2,8	Mw
Renewable Installed power	0,3	Mw
Available SCADA for Generation Control	Yes	
Controls some breakers	Yes	
Operated Radial	Yes	
Number of feeders	3	

KOSRAE single line diagrams





The Project
13.8kV
Aluminum
336.4MCM
(170mm²)
Neutral line
Aluminum
3 / 0 AWG
(85mm²)
AWG No.4
(21.2mm²)
1inch = 25.4mm
1feet = 304.8mm
1mile = 1,609.344m
3 Phase ACC
3 Phase AL AWG3/0
3 Phase
Single line
GEN-10 750kVA 600kW 900rpm
GEN-11 750kVA 600kW 900rpm
GEN-9 750kVA 600kW 1800rpm
GEN-8 1,312kVA 1,050kW 1,200rpm
13.8kV / 0.48kV-0.415kV 300kVA IZ:5% STATION TRANSFORMER
4.16kV / 13.8kV 2.5 MVA IZ:5.75% TRANSFORMER-B
MALEM LINE
LELU LINE
TAFUNSAK LINE
0.24kV / 13.8kV 225 kVA IZ:1.6% STEP-UP TRANSFORMER
0.24kV / 13.8kV 112 kVA IZ:2.0% STEP-UP TRANSFORMER
PV 200kWp
PV 100kWp
UNDERGROUND CABLE(16-19) 4PH, 50mm2 ALUM XLPE/AWA/PVC
TAFUNSAK TOWN AWG NO. ½ AL, 3 PH
OKAT INNER RD. AWG NO.4 CU, 1 PH
SEMO AWG NO.4 CU, 3 PH
UNDERGROUND CABLE TO AIRPORT 3 PH, 50mm2 ALUM XLPE

An existing SCADA System controls the frequency and co-ordinates Units in Diesel groups.

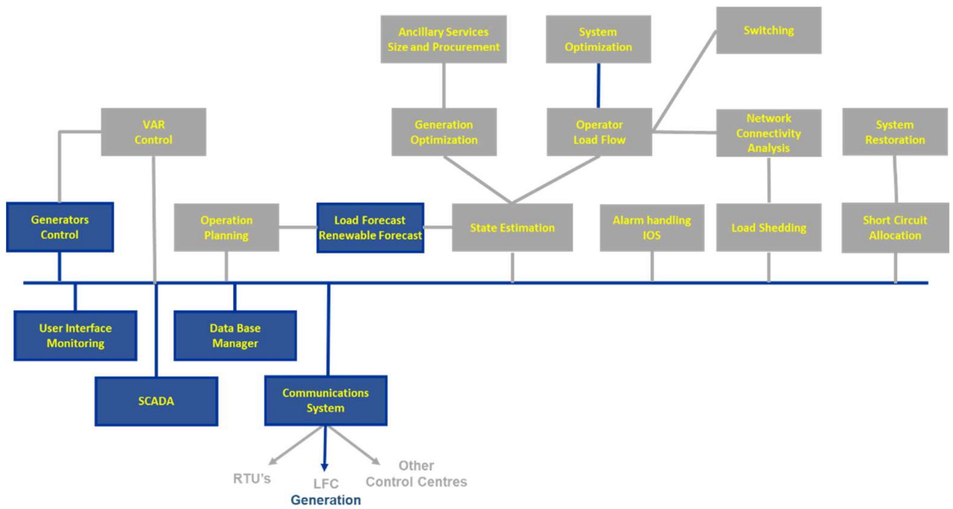
Functionality is limited to:

a. Full control of the generation units, including some optimization of the generation assigned to each unit.

b. Basic control (switching) of some feeder heads. Plan to expand it to some other substations

c. No additional functionalities available in top of the SCADA

The figure shows the actual SCADA configuration:



Battery & VRE control systems that have SCADA functionality also have the same capability to perform basic control functionality (such as open and close breakers), monitor system status (breaker positions, power flows, voltages and currents), alarms, Generation Control, a User interface to display diagrams and trends, and record data. There is the potential for Diesel, Battery or VRE control systems to provide some or all of the functionality described below but this has to be investigated on a case by case basis.

5.6 Applications Proposal

There are plans to expand the functionality of the SCADA to improve the network system operation.

Any expansion can be organized in different ways, one is doing it in a single step the other one is perform the expansions in two or three steps.

The first option has the advantage that all functionality will be available as soon as possible, the second one delays the full functionality but allows a more consolidated knowledge step by step.

Training is an important aspect and the second alternative will allow to consolidate one knowledge and functionality before starting with the second set of functions.

In the following points the possible expansions and the recommended one will be developed.

5.6.1 Priorities

The priority for improvements:

1. Improve quality of Service
2. Economic Optimization (Reduce Technical losses)
3. Detect non-technical losses

5.6.2 Functionality proposal

Two steps are considered, the first one oriented to quality of service and the second oriented to economic optimizations in network operation or loss reduction.

5.6.2.1 Quality improvement

In the first step, the functionality propose id to include all applications related with the quality control and improvement.

Specifically:

1. **Short circuit allocation**. Once installed in the network, some detectors of short circuit current (as an example, an overcurrent relay or a specific detector) and their detection sent to the centre.

   If in this location there is an RTU, it can be used to include this signal, as any other in the RTU communications. As an alternative, for those measurement points, where no RTU is installed, communications could be based on Power Line Carrier (PLC), fibre optic links or GPRS sim cards.

2. **Load Shedding**. Load shedding is the capability to disconnect from the network some selected loads, when some specific system conditions are reached:

   a. When the frequency reaches a certain value, the load will be automatically disconnected. The total amount of load could be a percentage of the actual load (50%) in 3 to 5 steps of frequency and load. The objective is to stop the drop of frequency before reaches the value where the units will be disconnected for security reasons. If this point is reached, shedding will produce a general blackout of connected loads.

   b. Manually from the control centre. When some specific situation can take place that does not fulfil the security criteria and could lead to a general blackout that can be avoided by disconnecting a certain level of load. This load can be disconnected from the control centre.

3. **State Estimation**. Contrary to the EMS, where state estimation calculates the Voltage and Flows and corrects missing or erroneous loads and generation, the DMS calculates the load values in intermediate not measured points.

4. **Operator Load Flow**. Calculates intermediate voltage and flows between the different not measured lines or cables. It is obvious than in distribution is not practical to install an information point at each transformation to low voltage, to measure all loads in the system, but for forecasting, flow control (considering the different cables/lines capacity), operation planning and voltage control, it is valuable information.

5. **Voltage and VAR control.** Voltage is one of the main indicators of the quality of the system. The main tools to control the voltage in the network are, ordered by priority:

   a. VAR control by generating units, including Diesel units and, if possible, wind and solar generation.

   b. Transformer taps, which can be changed in hot.

   c. Batteries, SVC's or STATCOM, to control voltage in different network points.

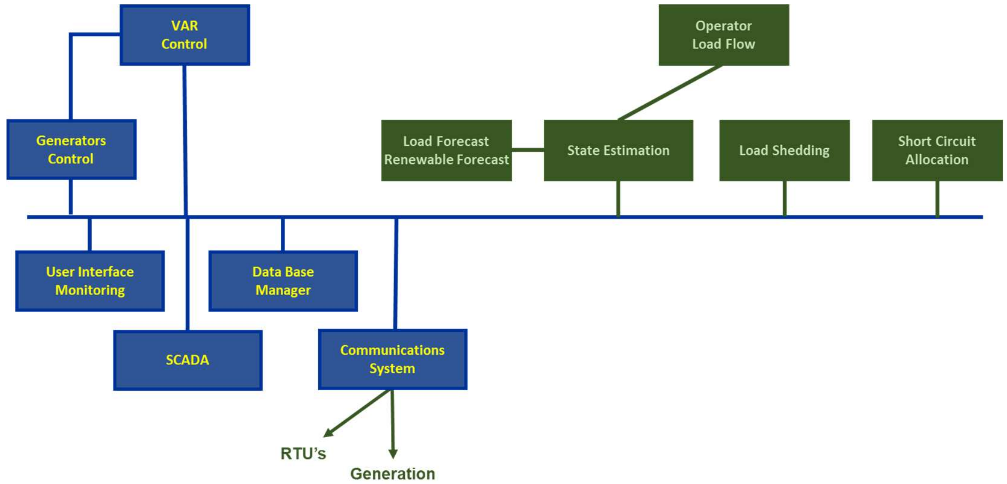
   d. Shunt devices (reactance's)

   e. Transformer taps, which cannot be changed in hot.

A weight methodology will determine the optimal solution.

Load and Renewable forecast. Forecast is a technology to preview some values using not only the historical cleaned data base, but also the variable parameters: Temperature, sun insolation, clouds, rain… These values are needed for generation optimization.

The functionality, after this phase shall be:



5.6.2.2 Economic Optimization and technical loss reduction

1. **System Optimization.** The technical losses are a function of the resistance and the quadratic of the current circulated between two points. Resistance is a value that depends on the infrastructure and characteristics of the lines or cables. But the Current depends on the network topology. A Minimum could be reached by modifying the network topology, moving loads from one feeder to another or making some loads in parallel, without closing loops.

   This function together with other possibilities (voltage management…) will determine the topology with minimum losses.

   At the beginning, the capability to apply this functionality (topology modification) could be not high enough but following applications can be used also to select the optimal planning options, which will habilitate the use of this function for planning and present conditions.

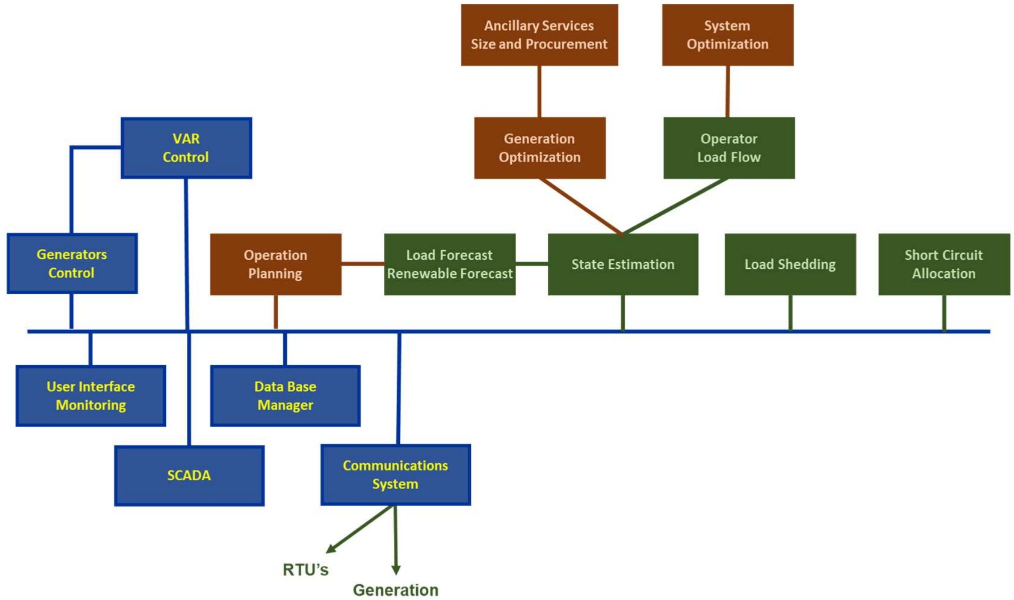
2. **Generation optimization**. After the load and Renewable forecast, we have the amount of energy to be produced by the conventional generation. The split of this generation among the different groups or energy sources will define the optimal generation profile, considering the energy costs, including hydro generation, the system losses and ancillary services requirements like Reserves or Voltage Control.

3. **Ancillary Services** are defined by FERC as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." Certainly, the KOSRAE system is not inside the definition of “transmission interconnected systems” but is also true that to operate a system like KOSRAE requires consideration of the need for Ancillary Services

   The evaluation of the needs of ancillary services includes reserves of different types or the Voltage Control requirements. The evaluation of Ancillary Services must be allocated and monitored in real Time.

4. **Operation Planning**. Most of the functionalities described above are potentially used for operation planning, evaluating the different alternatives presented.

The functionality after this second phase will be (in brown tones is the second phase):



5.6.2.3 Functionality not recommended

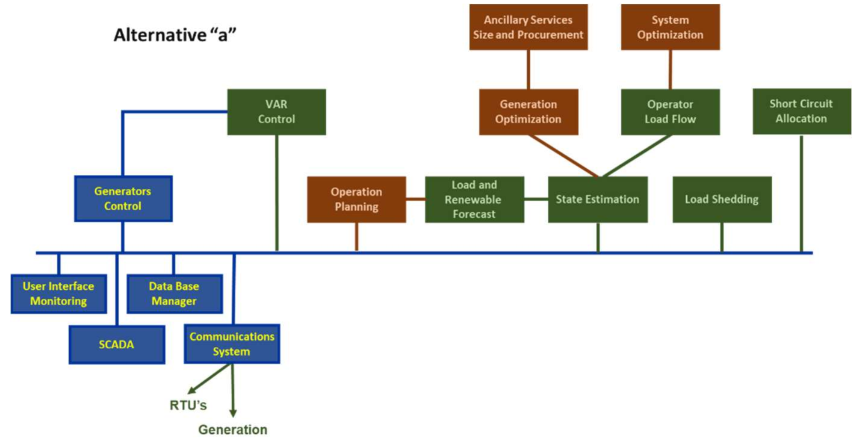
Some functionality is more oriented to much larger systems, where an operator cannot have a detailed knowledge of the full grid. This is not the case observed in the KOSRAE electricity system. These functions are not recommended.

1. **Switching**, proposes a sequence of network operations to restore the system, after an incident, or to prepare the isolation of a network section for maintenance purposes.
2. **Network connectivity.** Analyses the system topology watching for loops or parallel sections, **which** may produce a loss on protections selectivity.
3. **System restoration,** after an incident, these applications calculates the sequence of **operations** for optimal restoration of areas in blackout.
4. **Intelligent Alarm Operation.** Alarms are generated in the RTU's or at the control centre if some of the values received exceeds the established limits. In case of an extra high number of alarms and messages some intelligent selection or grouping of them is required to avoid submitting to the operator an excessive number of alarms. This functionality is useful in case of hundreds of alarms, but of little value for small systems with few alarms.

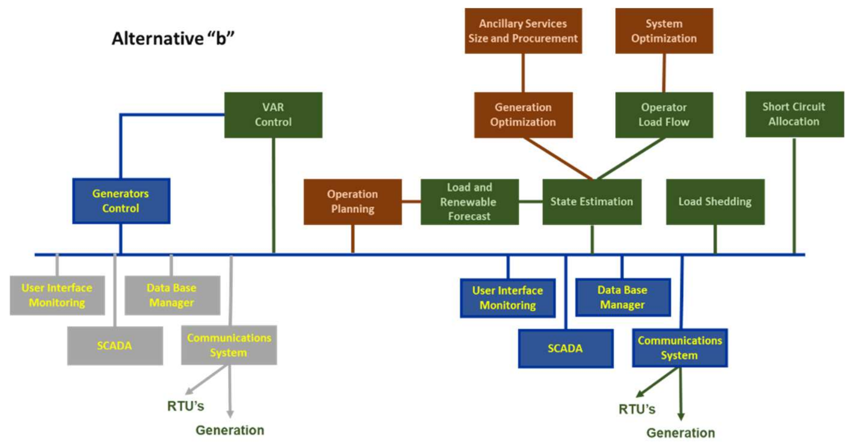
5.7 Architecture Potential alternatives

Assuming that the system functionality is the one selected, there are few potential architectures of the system with their own pros and cons. The following alternatives apply:

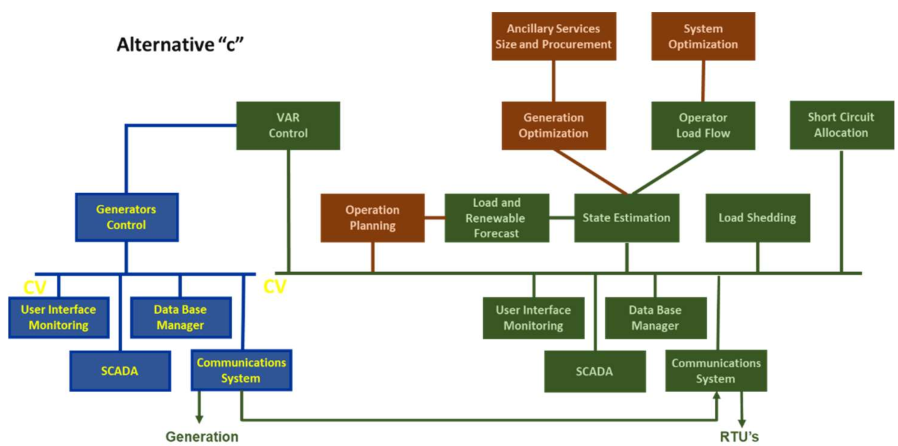
a. Use the actual SCADA system that is available in the KOSRAE system for diesel generation control (blue blocks in the following figures) and expand its functionality with the one required for distribution network control (green blocks at first step, and brown in second).



b. Use a new and more powerful SCADA System, with the new grid and generation applications and transfer the generation operation to the new SCADA.



c. Add a new SCADA for network application and maintain the old one for conventional operation.



All alternatives are potentially acceptable, but some aspects shall be take into consideration, before taking a decision:

- The alternative “a” will require to increase the functionality of the actual generators control system. It’s not clear that this functionality already exists and been tested and in service in other installations.
- Alternative “a” will require to modify the existing control of generators, especially if the software versions of network applications (operating system, data base…) are not compatible with the existing, installed some time ago.
- Alternative “b” will require a new version of generators control functions, if available, in the network applications provider, for the installed generators. It is a risky situation to programme a functionality to control generation, while now is working at satisfaction.
- Alternative “c” requires new hardware and will become a separate system. Maintains the generators control as it is.

Considering those aspects and because:

- It is mandatory to maintain the generators control provided by the generators supplier, that works satisfactorily, and we do not want to compromise this activity and take extra risks.
- The cost to program and adapt new functions and introduce them in a working system, has always a certain level of risk
- Due to the actual cost of hardware has been reduced for a same power and capacity
- Due to the capacity to cooperate between the different utilities in the region, as will be explained below

Considering those reasons, and the system size, we recommend the first phase 0f the alternative “c” as optimal solution, complete the option “c” shall be considered in the future. Maintain the actual system conditions could be an acceptable conservative solution.

Especial economic considerations shall be considered due the economic impact of the investment and operational costs per kwh served.

5.8 Additional elements to install in the network

To make the functionality proposed develop its full capability, some additional elements shall be installed in the network:

- Remote Terminal Units
- Capacity to modify the system topology
- Communications and protocols
- Cyber Security

5.8.1 Remote Terminal Units (RTU’s)

RTU’s are the terminals that give to the SCADA the information needed monitor the network, introduce topology changes and execute the applications.

An RTU can have the capability to read and transmit or execute:

- Analogue values as voltage and flows
- Digital values as breakers or isolators position, relays activity as protections or short circuit current detection
- Execute orders as open or close, up and down (transformer taps)

The optimal location of the RTUs is based on the load type, load capacity, level of voltage reductions and failure rate.

Other criteria are the communications capability and the availability to have energy supply facilities.

There are some algorithms that help to optimize the RTU location.

Considering the topology of the network in KOSRAE, to start with, the number of RTU's shall be around 3.

5.8.2 Capacity to modify the system topology

One of the advantages of the SCADA is to intervene and modify some of the main parameters of the network, like the topology.

Open and closing some of the isolators or breakers the flow direction of the energy will change as the feeder's configuration changes.

Depending on the characteristics of the element to be operated, with or without flow as example, will provide more flexibility to intervene in the topology.

The best use is in case of an area in blackout, the topology changes may reduce the area isolated.

5.8.3 Communications and protocols

All communications technologies are available to be used from PLC to Optical Fibre going thorough radio or GPRS sim cards.

The set of standard protocols are used for this communication, most of the systems can offer more than one. Standard protocols have the advantage that RTUs from different vendors can be mixed in the network, which helps to reduce the RTU prices by introducing competitive pricing.

The operation of the SCADA system is dependent on reliable communication from each station to the central control station. International best practice recommends that Power Utilities establish their own communication network and not be dependent on public Telecommunication operators. A Telco's objective is different to earn revenue from selling bandwidth, whereas a Power Utility has to ensure the reliability of the power network. We therefor recommend that a utility owned Telecommunication network be established to provide the communications required for the Control system.

The protocols used can be divided in four main groups:

a. For many years the SCADA suppliers have imposed proprietary protocols, used exclusively in their own installations. This situation creates a dependency between the supplier of the RTU's that should be the same (or compatible) with the SCADA system if you want to avoid that an RTU supplier shall emulate the SCADA protocol with the information provided by the supplier. This situation is changing but some of those protocols are still in service due to extended usable life of RTU's.

b. Some general-purpose protocols like Modbus or DNP (Distributed Network Protocol) are quite efficient for use in the Electricity Networks control, at different levels. Despite the age of these protocols, they are still in use (Modbus was created at the end of 70's), with good results.

c. Special protocols are designed by international standardization bodies such as IEC (International Electrotechnical Commission), specifically for Electricity Systems applications such as the IEC 60870 series of standards. The IEC 60870-5-101 and 104 protocols provide serial and IP connectivity, respectively, between the IEDs and RTUs in the substations or generation plants with the control center. The IEC 60870-6, also known as TASE protocol, provide communication between the control centers. The advantage of these application protocols is interoperability, that allows multi-vendor option for systems and elements.

d. The Internet Protocol (IP) is the principal communications protocol used in the Internet, using source and destination addresses. Its routing function enables internetworking and is useful for connection between RTU's in the Field and with the Control Centre

All those protocols could be used, but some precautions need to be taken, especially in communications security.

The selection of the protocol will depend on the communication technology that is decided upon, and can be finalised during project implementation.

5.8.4 Cyber Security

As in any other control centre the cyber security is a must in order to protect the information and the access.

Some security standards developed by FERC or ISO, among others will be helpful to maintain under control the system operative

5.9 Procurement, Training and Commitment

The activity of procurement will consist of:

- design of the system including the functionality,
- preparation of technical specifications
- preparation of a call (tender) for offers and to accept bids from different potential providers (open to any potential participant or a short list of suppliers), including all the terms and conditions
- Evaluate bids and decide the winning offer and contract negotiation and signature

Once the supplier has been accepted and before the commitment, the training process shall start where the personnel will be trained in the administration and maintenance of the system and to its use by the network operators.

The commitment shall include the installation in the final location and all tests before final acceptance.

5.9.1 Procurement

The main activity for procurement is, based in a previous design, prepare the technical specifications and contractual conditions to ask for offers to some potential suppliers.

Once the process to receive the bids is done, the decision mechanism, included in the offer conditions, will be applied to determine the winner bid.

The following step will be the contract negotiation, based on the contractual conditions included in the offers request.

The activity of procurement is highly time consuming and in consequence has a high cost associated.

In the case of utilities working together for procurement purposes, this activity will need to be repeated for each utility that wishes to establish a network control as designed above.

For the procurement between all or some of the utilities, common specifications and similar systems can be procured for each utility, with adjustments for the hardware requirements for each one.

For the utilities grouping in this process, should be able to report certain time and cost advantages:

- ✓ One core technical specification should be valid for the all systems. This will reduce the number of specifications and contractual conditions to be prepared.
- ✓ The individual price obtained for group of systems will be lower than independent individual negotiations for each one.
- ✓ During the negotiation for a group of systems some other advantages, besides the price, could be achieved.
- ✓ It will be possible to share some spare parts, that will also reduce the global cost

For all those reasons we recommend preparing common specifications and request offers for a group of systems to be developed together and with the same basic functionality.

Some location specific aspects can be included, as options.

5.9.2 Training

As part of the contract, the two training activities should be developed: training of administrators and users.

- ✓ Training for administrators is specially oriented to maintenance of system hardware and software, particularly the application of new versions, and the ordinary system maintenance, population and expansion of Data Bases, RTU's, communications… Resolution of any kind of problems, with the objective to maintain the system operation.
- ✓ Users training is to prepare the potential operators to perform and execute all applications of the system, included supervisory control or prepare reports, as examples.

This is knowledge that should be acquired in the utility and must retained by it.

But there are additional aspects that shall be considered:

- ✓ The minimum number of people assigned to SCADA in each utility. As administrators, should ideally be between 2 and 3, due the fact that there are unavoidable vacation or illness periods and the risk that one may decides to try other working options. However, in the Pacific Islands, staff resources are usually limited, so other options are:
- ✓ Sharing the trained resources among the different utilities, considering the capacity to be connected from distance, with secured communications, will reduce the number of formed administrators to 1 or 2 per utility.
- ✓ On the other hand, organize training courses for 2 or 3 people many times, in different locations, is an expensive scenario, compared with a single session for 10 to 16 administrators in the same location. Similarly, valid for users training

Because of this, joint training and agreements for support among them will reduce the training and operational costs for each utility.

In consequence of those aspects, we recommend a joint training and an agreement between all utilities for a common support.

5.9.3 Commissioning

Includes all tests for acceptance and the installation on site.

Tests are commonly divided in two:

- Factory Acceptance Test (FAT) where the supplier executes the tests and is witnessed by the client. All functionality is tested. No real data will be available, but the data could be simulated and loaded to the system from another computer that simulated the field. Until the results of FAT are not satisfactory, con not start the SAT.
- Site Acceptance Tests (SAT) where the system is tested by the client in their own facilities, with real data, and must be witnessed by the supplier. With the acceptance of SAT, the system is accepted, and the guarantee period starts.

As mentioned before, if there is an agreement between a number of utilities, the supplier can run a single FAT process, which is an expensive activity, instead of independent FAT for each individual system. This way, the coordination of utilities will reduce the testing costs, without reducing its effectiveness, which will reduce the global costs for the supplier and in consequence for the utilities.

SAT must be carried on each system independently, but after initial problems detection and solving, normally the remaining ones will go much faster, with the same acceptable results.

Those conditions lead us to suggest again an agreement between all utilities to make a joint test of the systems.

All aspects commented in the previous points regarding the development of a consortium, are aimed at:

- ✓ Simplifying all activities related with the commitment of a new system
- ✓ Reducing the final price of each system
- ✓ Establishing a cooperative framework to maintain updated and solve potential problems in the day by day operation.
- ✓ Maintaining the utility financial independency and its juridical personality.

With all those reasons we suggest reaching an agreement for Procurement, including spare parts, training, test, commitment and operation of the Network SCADA Systems.

5.10 Cost Benefit Analysis (CBA)

The Cost Benefit Analysis must include the following aspects:

1. Procurement and Installation financial cost
2. Operational costs
3. Evaluation of benefits obtained

The useful life time for the system, for reasons of CBA calculation is set at 10 years.

The results of these analysis shall report if the operation is economically sustainable or is a cost centre for the utility.

5.10.1 Installation financial cost

Corresponds to the cost of the procurement, test, training and commitment of the SCADA System, including potential financial costs.

Those costs shall include:

- ✓ The SCADA hardware and software
- ✓ Commitment of the system, including training and test. Exclude decoration of the Control Centre.
- ✓ For the study a total of 4 RTU's shall be considered, including needed network elements and the RTU itself.
- ✓ Communications required at RTU's and in the Centre.

Considering the potential cost reduction for agreements between electric utilities.

The useful life-time of the system can be set to 10 years.

5.10.2 Operational costs

The operational cost can be considered in 1 or 2 additional people during the useful life of the system. This assumes that the administrators of the actual system for generation control will take part also in the Network SCADA system, as administrator.

1 additional full-time personnel is needed in the case of a cooperative environment, and 2 additional personnel in an isolated scenario.

The reason for those values is the need to guarantee that knowledge remains in the company and, on top of this, the expert must be available in presence or in call during for 7x 24 hours. With one expert, this is not guaranteed due to working calendar availability (vacations or illness).

So in this case, a minimum of 2 operational experts are required at all the time, however more is recommended. But. But in case of a consortium (coordination between the utilities) , this third person, could be a reserve for substitution in other utilities, when needed for a limited time..

This is way in case of NO consortium, the need to contract people will be the 3 needed minus 1, the actual expert, which make 2 new employees.

In case of consortium, the need to contract people will be the 3 needed minus 1, the actual expert and minus 1 evaluated as the assistance between partners in the consortium, which make 1 new employee.

No termination costs need to be considered. As per experience, once the useful life is over either for size of the system or obsolescence of some equipment, the system will be substituted by another one and the expertise acquired by the administrators will be very valuable for a new system.

5.10.3 Benefits

The benefit that incorporates all improvements in network control are in the reduction of the number of partial or total blackouts and the reduction of the extent and duration of those blackouts.

The difficulty will be to evaluate the reduction in blackouts and evaluate the benefit of this reduction.

The benefits are tangible in those aspects related with a non-supplied energy and immaterial for the image of the utility in any scenario, owned by some public administration or a private ownership.

First one can be quantitatively approached while the second only accept qualitative considerations.

This is a very complex issue. Two alternatives have been considered in the time, both equally valid, but with very different results:

5.10.3.1 From the utility perspective.

It is obvious that the utility suffers in its image from blackouts. But no monetary costs shall be considered besides there is an easily quantification for image recovery (discounts to clients, sometimes as per law, advertising in TV or similar…).

Considering the direct cost of the blackout there are two components:

- There is an energy not supplied, but at the same time is not produced, so does not consume extra fuel. It is an almost even balance.
- There was a benefit expected for the sale of the unsupplied energy that now is not obtained.

Damage in the network shall be covered by an insurance policy either with insurance outsourcing or by auto insurance.

Those costs were approached by a named “cost of unsupplied energy”, which is evaluated in as many ways as utilities. Perhaps the average is considering 10 times of the clients cost or the most popular tariff.

5.10.3.2 From the society perspective.

It is true that the cost impact of a blackout to the civil society is also higher: loss of production in some factories, commercial activity stopped for a certain time. Damage of some goods at each one home, due the loss of refrigeration, loss of capacity to recover electronic communication means (TV, Laptops, smart phones…), Hotels image in front of their clients may comport economic losses, and in top of them the loss of personal or home security aspects due the darkness or the unavailability of alarm systems.

All those aspects are not included in the cost of a blackout but their impact into the country economy is much higher than the impact on the utility economy.

For this reason, a second methodology has been developed lately considering the economic impact that a blackout of variable duration may produce.

Public companies shall consider, at least partially, this social cost.

It is clear that for the CBA will be much easier to evaluate costs than profit, but simple analysis must show clear benefits.

5.11 SCADA Conclusions and Recommendations

Considering the aspects expressed above, we recommend:

- ✓ Establish one topology based on the maintenance of the existing SCADA to control the conventional generation.
- ✓ Implement a new SCADA system for network control
- ✓ Functionality regarding the Quality of Service will be in the first phase. When this phase will be consolidated, then a second phase with the Economic Optimisation and Losses Reduction will be implemented.
- ✓ Together with the first phase, the commitment and test of at least 3 RTU’s.

- ✓ For `procurement, training, commitment, test and commercial operation we recommend achieving an agreement with other utilities to reduce the investment and operational costs.
- ✓ To calculate the Cost Benefit Analysis, we recommend considering the investment and financial costs for an expected life of 10 years, the operative costs for the same period and the social benefits attached to the reduction of blackouts in extension and duration.

5.11.1 Recommendation for staged implementation and roadmap: Kosrae

We recommend the following staged implementation roadmap with the scope and objective of each stage as indicated:

	Stage 1: Deploy basic SCADA	Stage 2: Extend and deploy level 1 DMS functions	Future: Deploy level 2 DMS functions and other technologies
Capabilities	Establish basic SCADA capabilities of the Power station, PV plants and reclosers on the 13.8kV backbone with the ability to perform remote switching of the network	Extend the SCADA to include all PV plants Implement level 1 DMS functions (as listed below) to optimise the operation of the power network	Implement additional DMS functions (as listed below) Extend the SCADA visibility to the LV network using SMART meter technology
Objectives (benefits)	Monitor the status of the power network and the status of generation from a central control station and improve detection of outages, alarms and voltage violations Operate the power network (i.e. perform switching) from a central control station to improve restoration and safety	Improve the scope of visibility Improve plant overload detection and protection co-ordination with load flow and short circuit calculation capabilities Improve scheduling of generation with better load forecasting and by considering the available renewable capacity Improve grid security with emergency / block load shed capability	Support the implementation of virtual power plants to improve balancing of supply and demand Improve the control of the microgrid by supporting energy storage capabilities Reduce distribution system losses through volt/var optimisation Reduce demand and energy consumption through conservation voltage regulation

The scope of each stage proposed is detailed here below.

Stage 1: Basic SCADA

During this stage we recommend SCADA visibility be established from the central control station for the main 13.8kV backbone switching nodes including the Power stations and the main PV plants with the following capabilities:

- Monitoring of the following:
    - Switch positions (status of breakers and isolators)
    - Basic power flow measurands (e.g. amps, MW, MVAR and voltages) at key network positions
    - Transformer tap positions
    - Alarm signals limited to common / grouped alarms
- Provide remote control capability of:
    - Open / close of switches (breakers and isolators)
    - Set generator setpoints and limits

    - Raise / lower transformer tap positions

- Visualise the status of the power network including topology processing to indicate the energized / de-energized / earthed parts of the network.
- Integrate with the existing SCADA and Generation Control system deployed at the Power station. Retain the existing frequency control mechanism.
- Record the load profile and generation data for future load forecasting.

The main dependencies during this stage are:

- Communication

  The operation of the SCADA system is dependent on reliable communication from each station to the central control station. International best practice recommends that Power Utilities establish their own communication network and not be dependent on public Telecommunication operators (A Telco's objective is different to earn revenue from selling bandwidth, whereas a Power Utility must ensure the reliability of the power network).

- Plant capabilities

  The implementation of SCADA is subject to the capability of the installed plant, especially to accept remote control signals. The plant information available to us at this stage is limited and this needs to be confirmed in the next project phase.

- Topology model

  The topology processing (to identify energized/de-energized state of the network) will require the connectivity of the plant to be modelled. This requires accurate network data to be available which is typically captured in a GIS based system or in network schematic diagrams. The availability of such data needs to be confirmed in the next project phase.

Stage 2: Extend SCADA and deploy level 1 DMS functions

During this stage we recommend the extension of the SCADA visibility to include all PV plants and deploy some DMS functions listed below:

- Include SCADA visibility of all PV plants.

- Load flow study module:
  This will enable load flow studies to be done via the SCADA system considering the actual network condition or simulated network conditions. Network overload and voltage violations can be studied for different operation conditions and by simulating different network topologies (e.g. tripping of generators / transformers with or without PV plant being available).

- Short circuit calculation
  This module is an extension of the load flow study module to determine the minimum and maximum fault levels at different network positions and operating conditions. This information is important to validate the ratings of equipment and for protection co-ordination studies.

- Distribution load forecasting
  With this module the historical load profile and generation output data is used in combining with the weather forecast for short term load forecasting. The forecast of the available renewable capacity is considered to improve the scheduling and most economic dispatch of generation.

- Emergency / block load shed application:
  In the situation where insufficient generation capacity is available to meet the demand, the emergency / block load shed application will provide the ability to block load shed on a rotational basis to avoid inadvertent tripping of generators on overload. This improves the network security.

The implementation of these DMS functions are dependent on the following:

- Network model

  The DMS functions requires an accurate network model to be available. This includes both the connectivity model (as required for the topology processing in stage 1) and the electrical parameters of the plant. This requires accurate network data to be available which is typically captured in a GIS based system. The availability of such data needs to be confirmed in the next project phase.

Future Stage: Deploy level 2 DMS functions supporting other technologies

In future, the following DMS modules can be considered as the grid evolves:

- Virtual power plants module

  A virtual power plant/pool (VPP) is a collection of power generation sources (e.g. rooftop solar, wind), energy storage devices and demand-response participants located in a distributed energy system. Incorporating these VPPs will become increasingly important in future for utilities and aggregation of these VPPs needs to be considered in the SCADA / DMS to balance generation with the demand. The grid code policy and infeed tariffs will have an impact on the penetration of VPPs.

- Microgrid Energy Storage module

  This network is essentially a microgrid. The introduction of energy storage capabilities will improve the control of the microgrid and the use of renewable technologies. Any meaningful energy storage capacity introduced in the grid must be considered in the optimal dispatch of generation. The implementation of this module will depend on future storage facilities added in the network.

- Volt/var optimization module

  At present we expect the equipment available to regulate voltage is limited to the generator var control setpoints and the transformer tap positions. The ability to reduce distribution system losses with volt/var optimisation through the network is thus limited. This optimization can be considered in future when additional var control mechanism becomes available in the network.

- Conservation voltage reduction

  Similar to the volt/var optimization, the ability to regulate the voltage at the customer to reduce demand and energy consumption (mainly by resistive loads) can be considered in future when additional var control mechanisms becomes available.

- LV visibility

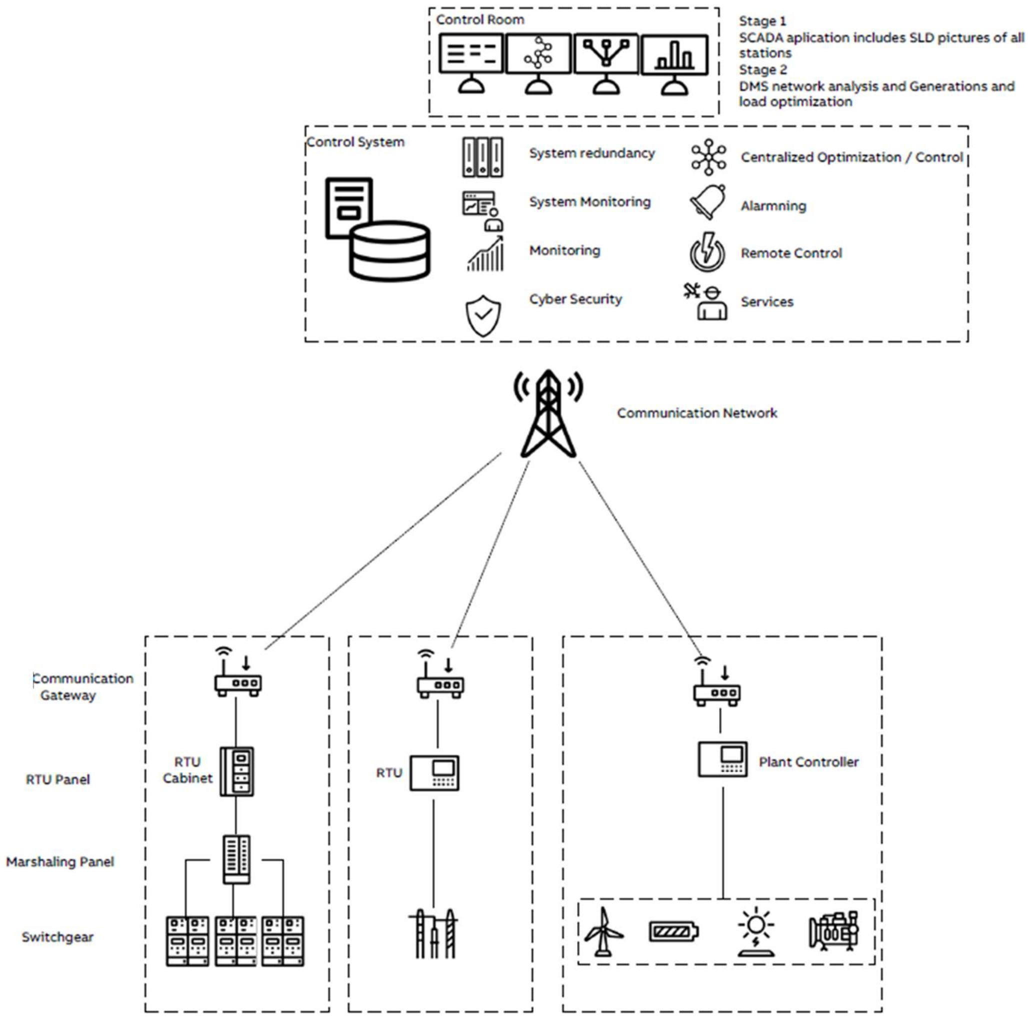
  Extending the LV visibility up to the customer can be achieved with the deployment of SMART meters with bi-directional communication. This can automate outage notification, identify voltage violations and support future volt/var optimization and conservation voltage reduction. This implementation will depend on MEC's SMART meter strategy, and integration with the SCADA central control should be considered in future when deployed.

- State Estimator

  The state estimator will be beneficial to provide estimated data for intermediate network points where analog measurements are not available. It may also be required if other optimization applications require a state estimator (which may be the case depending on the SCADA technology of the supplier). The State Estimator module is dependent on a network model like the Power Flow module.

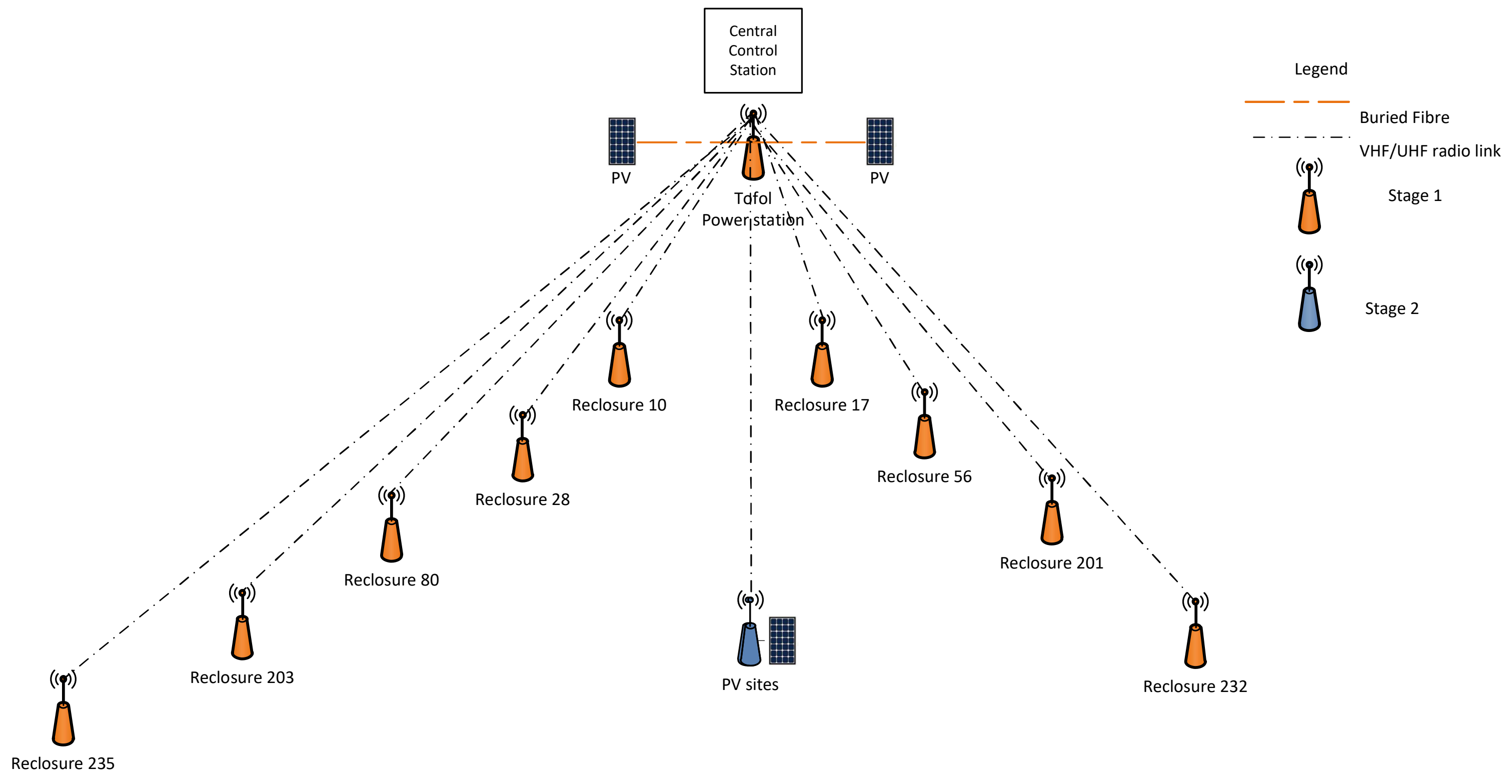
The conceptual design of the SCADA Control System is described in **Figure 5-1**.

Figure 5-1: Conceptual design of the SCADA Control System


Control Room
Stage 1
SCADA aplication includes SLD pictures of all stations
Stage 2
DMS network analysis and Generations and load optimization
Control System
System redundancy
System Monitoring
Monitoring
Cyber Security
Centralized Optimization / Control
Alarmning
Remote Control
Services
Communication Network
Communication Gateway
RTU Panel
Marshaling Panel
Switchgear
RTU Cabinet
RTU
Plant Controller

The conceptual design solution of the communication network is described in Figure 5-2.

Figure 5-2: Concept communication network diagram for Kosrae network



Notes:
1) It is assumed that limited Utility owned fibre optic cables exists, hence a radio based network is proposed for economic reasons and ease of deployment.
2) Due to short distance, each station links to the high-site near the power station. The position of the tower (less than 30m) needs to be co-ordinated with the airport.
3) Line-of-sight paths and signal propagation budget calculations need to be confirmed in the next project stage.
4) It is assumed the Central Control Station will be located at the power plant but can be located at any office in town with an additional communication link.

Figure 2: Concept communication network diagram for Kosrae network

5.11.2 Cost Estimate

The estimated cost to implement stage 1 and 2, based on the scope as described above and the conceptual design solution described in the appendix, is indicated in Table 5-1.

Table 5-1: Estimated cost for stage 1 and 2 for Kosrae

	Stage 1				Stage 2				
	Qty	Unit	Unit cost	Total cost	Qty	Unit	Unit cost	Total cost	Notes
Central Control Station									
Infrastructure works (building)									Excluded (scope unknown)
Hardware									
- Cabinet and network equipment	1	lot	$ 15,000	$ 15,000					
- Servers	2	each	$ 10,000	$ 20,000				$ -	
- Workstations	2	each	$ 3,500	$ 7,000				$ -	
- UPS	1	each	$ 5,000	$ 5,000				$ -	Limited capacity assuming standby generator
- Communication (link to Comms tower)	1	lot	$ 5,000	$ 5,000				$ -	Short buried fibre link
- Weather station	1	lot	$ 5,000	$ 5,000					To improve future load forecasting
Software licences	1	lot	$ 15,000	$ 15,000	1	lot	$ 30,000	$ 30,000	
Design and engineering	1	lot	$ 30,000	$ 30,000	1	lot	$ 40,000	$ 40,000	
Installation and commissioning	1	lot	$ 20,000	$ 20,000	1	lot	$ 30,000	$ 30,000	
				$ -				$ -	
Substations				$ -				$ -	
Hardware				$ -				$ -	
- RTUs: Main power plant	1	each	$ 30,000	$ 30,000					Provisional estimate subject to site audit
- RTUs (Reclosers)	9	each	$ 5,000	$ 45,000					Telemetry of switches on backbone 13.8kV
- RTUs (PV sites)	2	each	$ 5,000	$ 10,000	5	each	$ 5,000	$ 25,000	Telemetry of PV sites
- Transducers	9	each	$ 2,000	$ 18,000					Provisional estimate subject to site audit
- Communication equipment: Central Station	1	each	$ 20,000	$ 20,000				$ -	
- Communication equipment: Stations	9	each	$ 5,000	$ 45,000	5	each	$ 5,000	$ 25,000	
- Auxiliary DC system	9	each	$ 2,000	$ 18,000					Provisional estimate subject to site audit
Design and Engineering	1	lot	$ 20,000	$ 20,000	1	lot	$ 10,000	$ 10,000	
Installation, adaptation and commissioning	9	each	$ 10,000	$ 90,000	0	each	$ 5,000	$ -	Provisional estimate subject to site audit
				$ -				$ -	
Travel and accommodation	1	lot	5.0%	$ 20,900	1	lot	5.0%	$ 8,000	
Project overheads	1	lot	5.0%	$ 20,900	1	lot	5.0%	$ 8,000	
Contingency	1	lot	15.0%	$ 62,700	1	lot	15.0%	$ 24,000	
								$ -	
				$ 522,500				$ 200,000	

The cost for the future stage is subject to the scope of implementation of the additional DMS modules and implementation of other technologies (i.e. energy storage facilities, var control technologies, SMART meters etc.) and therefore cannot be estimated at this stage.

Appendices

Appendix 1: Grid Connection Code

Appendix 2: Description of GDAT model

Appendix 3: Description of SCADA and EMS

Ricardo
Energy & Environment

The Gemini Building
Fermi Avenue
Harwell
Didcot
Oxfordshire
OX11 0QR
United Kingdom

t: +44 (0)1235 753000
e: enquiry@ricardo.com

ee.ricardo.com