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Energy & Environment

## D4 – Draft Interim Report and Model for Pohnpei Utilities Corporation (Pohnpei)

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

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



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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 Countries" 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 Pohnpei 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	Fongafale (Funafuti atoll)

### 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 will be made:
  - Three phase fault levels;
  - Single phase to ground fault levels where vector group of transformers in the network is known and zero sequence current path of the network is properly represented in the model;
  - 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 will be 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 will form 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 will be increased in suitable increments (depending on the size of the network) and the following steps will be 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 5% ~ 10% higher than the existing maximum load demand level if the system has adequate network capacity.

- Renewable generation capacity (PV generation) considered to be at 10% to 40% of total installed generation capacity in the system. New renewable generation sites could be distributed across the system.
- Renewable generation will be fully dispatched in the considered operational scenarios. The conventional generators, however, will be 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 will then be performed:

- 6) Stability simulations to assess system frequency response for the two events:
  - o The sudden loss of the largest or the second largest generating unit on a system
  - o The drop and rise 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:
  - o 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.
  - o 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).

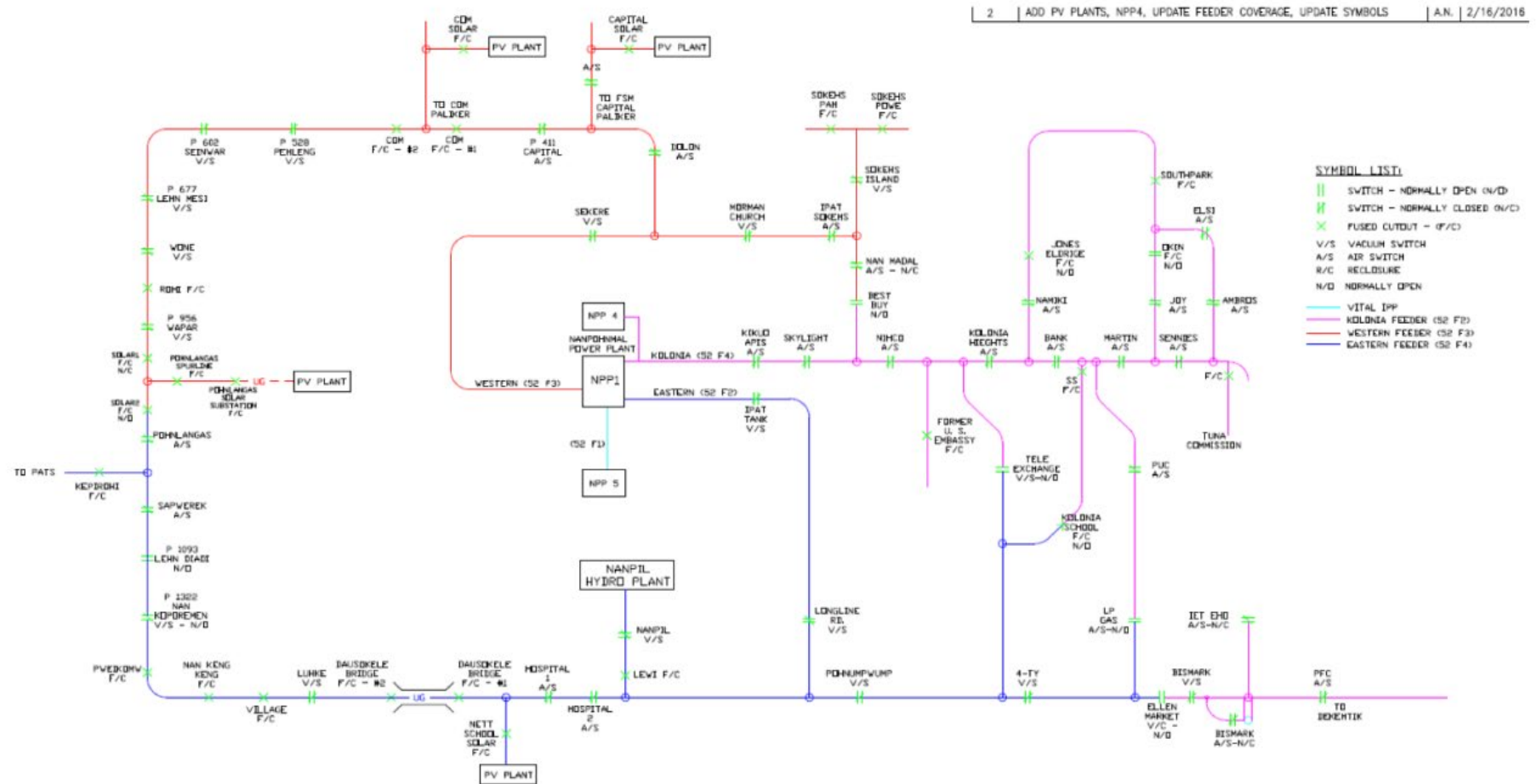
## 2.2 Pohnpei Network, Federated States of Micronesia

Pohnpei is one of the four states within the Federated States of Micronesia. The utility company in charge of operating and managing the power grid in Pohnpei is the Pohnpei Utility Corporation (PUC). The network under study for this project is the PUC power network on Pohnpei Island. The network is a 60 Hz system with a backbone network of 13.8 kV. There are three operational diesel power stations on the island, one of which has been decommissioned, a hydro power station and a solar PV plant. The power stations are interconnected and three separate 13.8 kV distribution circuit feeders carry power around the island.

The network SLD is provided in Figure 2-1 and shows the three feeders supplying the island.



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



A summary of the available generation capacity in Pohnpei is provided in Table 2-1.

**Table 2-1: Pohnpei installed generation capacity**

Name	Unit ID	Available Capacity (kW)	Type
Nanpohnmal (NPP1)	3516C_G1, 3516C_G2, 3516C_G4, 3516C_G5	4 x 1650kW	Diesel
Nanpohnmal (NPP4)	3512_G2	1 x 600 kW	Diesel
VITAL Power Station (NPP5)	VOLVO_G1, VOLVO_G2, VOLVO_G3, VOLVO_G4	4 x 350 kW	Diesel
Hydro Power Station	HPSG1	1 x 725 kW	Hydro
Pohnlangas PV	POHLOK	600 kW	Solar
President's Office	PALKIER (1)	20 kW	Solar
Elementary School	DAUSOKELE1	200 kW	Solar
COM-FSM	PALKIER (2)	160 kW	Solar

As can be seen from the table, the available generation capacity of the Pohnpei network in the system study is 10,305 kW, with 1,705 kW (about 16.5%) being renewable. The maximum demand of the network is around 5.1 MW, and the minimum demand is 3.7 MW. The maximum and minimum demands were measured in February 2018.

### 2.2.1 Power system data and assumptions

The data made available for the power system studies of the Pohnpei 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:

- Future generation plans – no future generation plans were provided for the island
- Switchgear fault ratings were not provided, only calculated fault levels at the 13.8 kV busbars
- Detailed power plant generation output was not provided – automatic voltage regulator (AVR) parameters are assumed.
- Grid code, local operational requirements – no grid code or local operational requirements provided. Primarily US industry standards are followed.

### 2.2.2 Summary of Power System Studies and Scenarios

The following table provides a summary of the power system studies performed on the Pohnpei 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, no PV	Loss of largest generator, loss of Western feeder, loss of Eastern feeder 3ph fault and feeder trip
Stability Study – Existing System, existing PV	Loss of largest generator, loss of Western feeder, loss of Eastern feeder 3ph fault and feeder trip Increase/decrease of PV generation
Stability Study – Existing System, existing PV, varied diesel generation dispatch	Loss of largest generator
Stability Study – 1200kW Renewable Generation Penetration	Loss of largest generator, loss of Western feeder, loss of Eastern feeder 3ph fault and feeder trip Increase/decrease of PV generation
Stability Study – 1200kW Renewable Generation Penetration, varied diesel generation dispatch	Loss of largest generator, 3ph fault and feeder trip Increase/decrease of PV generation
Stability Study – 2400kW Renewable Generation Penetration	Loss of largest generator, loss of Western feeder, loss of Eastern feeder 3ph fault and feeder trip Increase/decrease of PV generation
Stability Study – 2400kW Renewable Generation Penetration, varied diesel generation dispatch	Loss of largest generator, 3ph fault and feeder trip Increase/decrease of PV generation

### 2.2.3 Power system study results

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

### 2.2.3.1 Load flow studies

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

The scenarios can be summarised as follows:

#### *Maximum demand scenario*

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

**Table 2-2: Maximum demand scenario load flow results**

Demand Level	Maximum thermal loading (%)	Maximum Voltage (pu)	Minimum Voltage (pu)
Base Case	59.44	1.042	0.960
5% Load Scaling	62.79	1.043	0.957
10% Load Scaling	66.15	1.043	0.954

It can be seen from the results that there is adequate headroom for an increase in demand on the Pohnpei network when considering steady state operation, with a maximum circuit loading of 66% even with a 10% increase in demand across the island. The maximum and minimum voltages on the network range from around -4% to +4% of nominal, suggesting there are no issues but improvements in voltage profile would be beneficial and reduce losses. The voltage profile around the network 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: Minimum demand scenario load flow results**

Demand Level	Maximum thermal loading (%)	Maximum Voltage (pu)	Minimum Voltage (pu)
Base Case	32.09	1.029	0.984

The maximum loading on the network is recorded as 32% under minimum demand conditions. The maximum and minimum voltages on the network are both within standard operational limits for distribution networks.

### 2.2.3.2 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 and Table 2-34 shows the results of these.

**Table 2-4: Maximum fault level results for Pohnpei**

Fault Level	kA	Busbar	Voltage Level
Three Phase ip	9.648	NPP1BUS1	13.8
Three Phase Ib	2.508	NPP1BUS1	13.8
Single Phase ip	12.842	NPP1BUS1	13.8

Single Phase Ib	6.292	NPP3BUS1	13.8
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The fault level is highest at the power station busbars, which is to be expected. There were no switchgear or circuit breaker ratings provided for the 13.8 kV network and so a clear determination of the fault levels being within acceptable limits cannot be made at this stage. Based on standard switchgear ratings for these voltage levels, it is not expected that the system fault levels will be in excess of any rated equipment. However, it is recommended that the fault level results presented in the table above are compared against the switchgear and circuit breaker ratings to ensure if the network is operating within the safe limits of its protection system.

**Figure 2-2: 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

### 2.2.3.3 Stability studies

The voltage and frequency response of the system (maximum demand scenario) was assessed for a number of events including:

- 1) Loss of the largest generator on the system;
- 2) Loss of the Eastern Feeder;
- 3) Loss of the Western Feeder; and
- 4) 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:

- 5) A three-phase fault on the Western Feeder followed by the tripping of the conductor after 150 ms.

The parameters of the AVR's have been assumed for the conventional generators operating on the Pohnpei system, and in some cases the AVR's have been switched off (in Stability study 4) to minimise interference.

### **Existing generation with PV switched off**



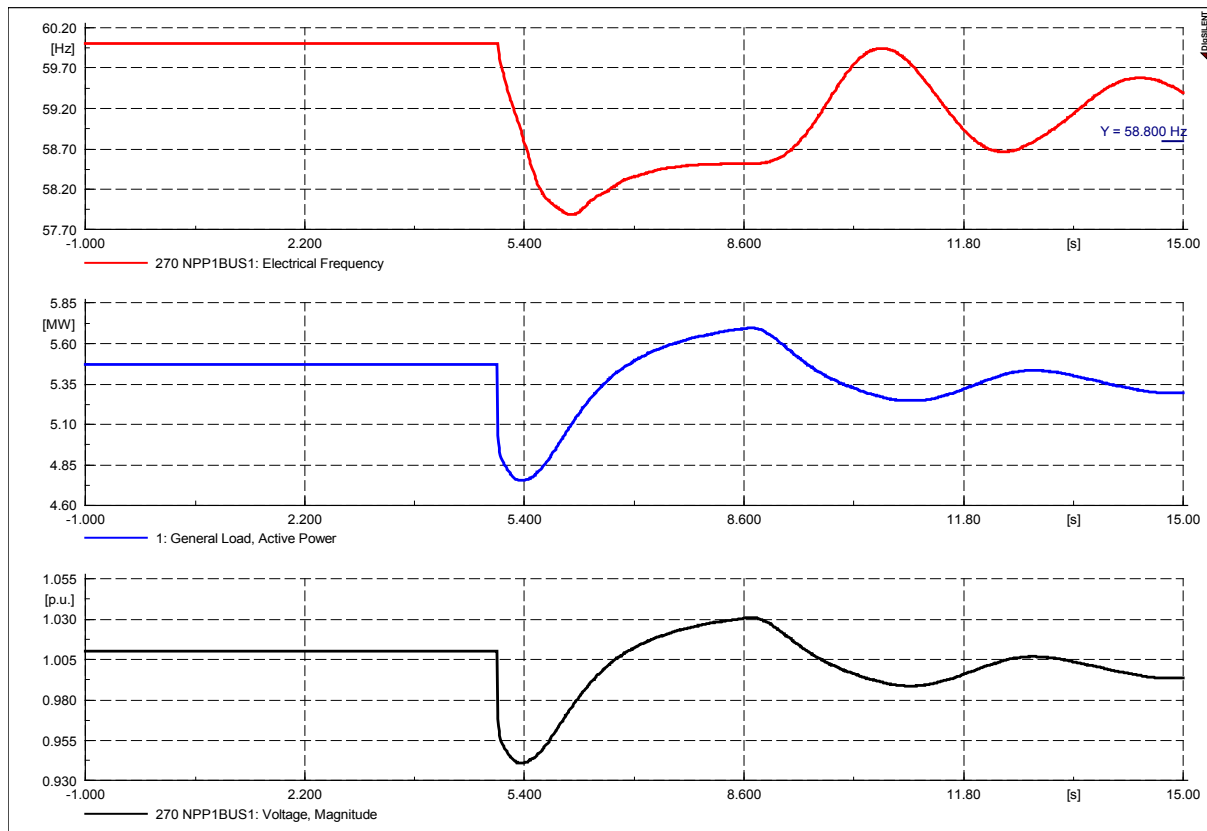
An initial set of studies was carried out on the Pohnpei network with no PV generation in operation, only conventional diesel generation and the hydro plant, to understand the behaviour of the system under these conditions. The generation mix for these studies is listed in Table 2-5 with approximately 1,667 kW of spinning reserve available in this scenario.

**Table 2-5: Generation mix on Pohnpei with no PV generation**

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel & Hydro	HPSG1	2	1	652.5	72.5	4.3%
	3516C_G1	3	1	1485	165	9.9%
	3516C_G2	3	1	1485	165	9.9%
	3516C_G4	3	1	1485	165	9.9%
	3516C_G5	3	1	550.5	1099.5	66.0%
	3512_G2	3	1	0	0	0.0%
	VOLVO_G1	3	1	0	0	0.0%
	VOLVO_G2	3	1	0	0	0.0%
	VOLVO_G3	3	1	0	0	0.0%
	VOLVO_G4	3	0	0	0	0.0%
	<b>Sub-total</b>			<b>5658</b>	<b>1667</b>	
Renewable	PALIKER (1)	1	1	0.0	0.0	0.0%
	PALIKER (2)	1	1	0.0	0.0	0.0%
	DAUSOKELE1	1	1	0.0	0.0	0.0%
	POHLOK	1	1	0.0	0.0	0.0%
	<b>Sub-total</b>			<b>0.0</b>	<b>0.0</b>	
				<b>5658</b>	<b>1667</b>	<b>29.5%</b>

### ***Loss of largest generator***

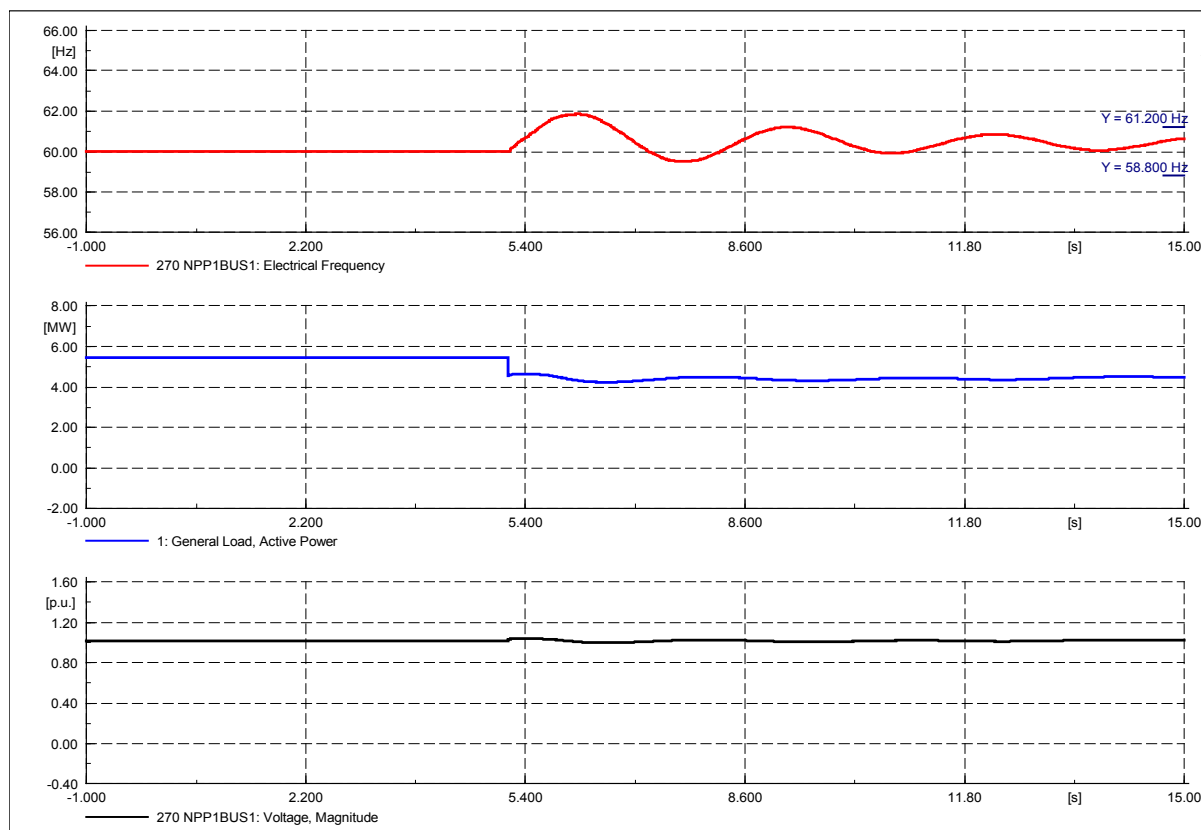
Diesel generator unit 3516C\_G4 is tripped in these studies as the largest generator on the system. The frequency and voltage response of the system are shown in Figure 2-62.

**Figure 2-3: Voltage & frequency response to loss of largest generator**

It can be seen from Figure 2-3 above that the system frequency exceeds the 2% allowable frequency deviation upon the loss of the largest generator (operated at 1,485 kW) on the system and reaches a minimum value of less than 58 Hz before slowly recovering. The voltage drops to around 0.94 pu. In order to prevent system frequency falling below 58 Hz subsequent to the loss of the largest generating unit, reducing its MW output level or increasing the number of generating units in operation may be necessary.

### **Western feeder trip**

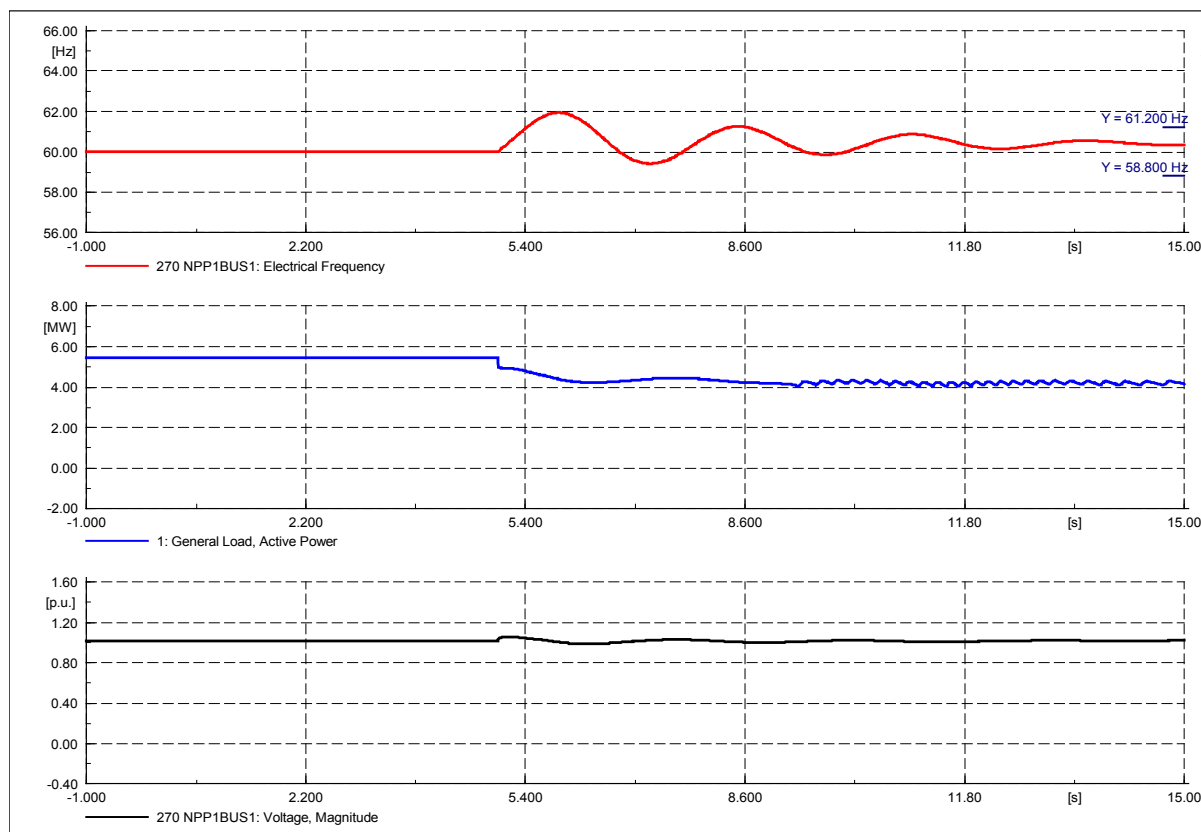
Tripping the Western feeder causes the frequency and voltage responses shown in Figure 2-4. The power transfer over the western feeder from Nanpohnmal power plant before the trip is around 1,095 kW, accounting for approximately 20% of the power supply from the power plant.

**Figure 2-4: Voltage & frequency response to loss of Western feeder**

The frequency increases slightly upon the loss of the Western feeder and it exceeds the 2% deviation limit for around 1 second before returning to within the acceptable bandwidth and settling. The voltage remains within limits for the duration of the study.

#### **Eastern feeder trip**

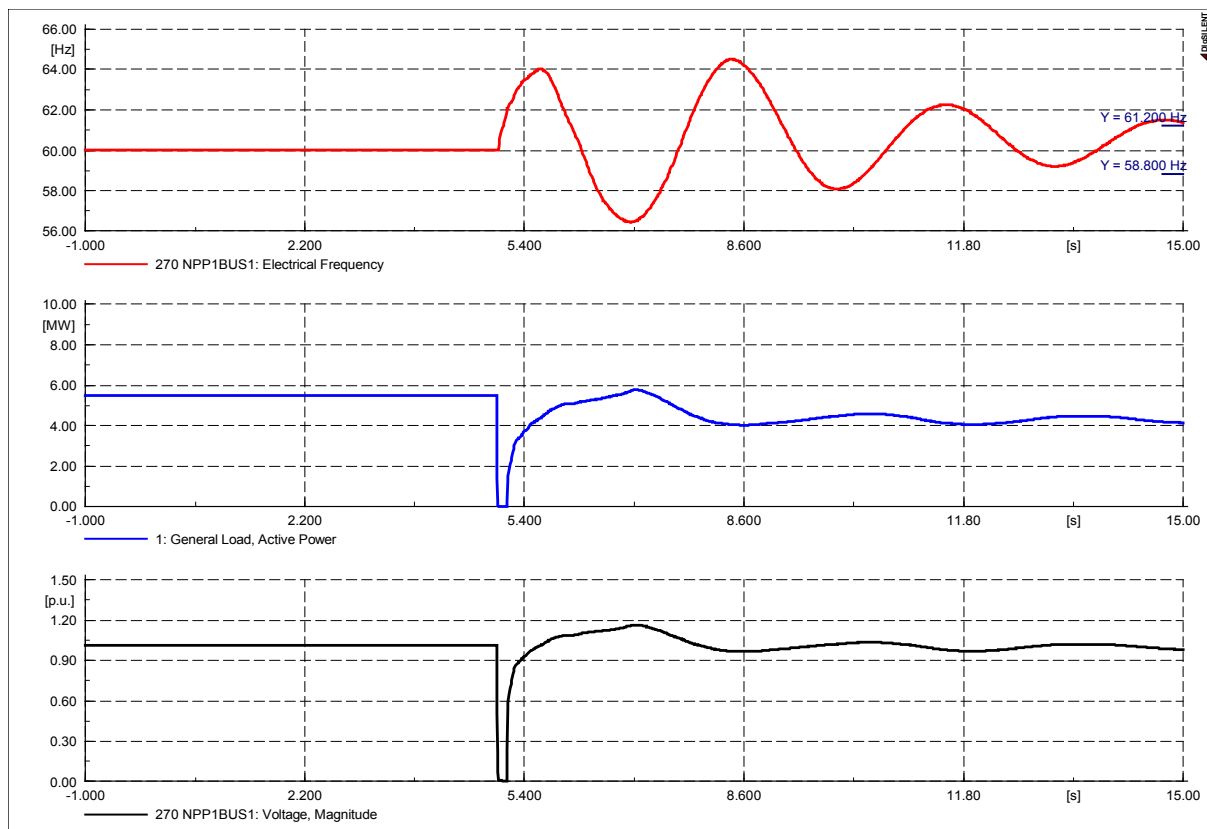
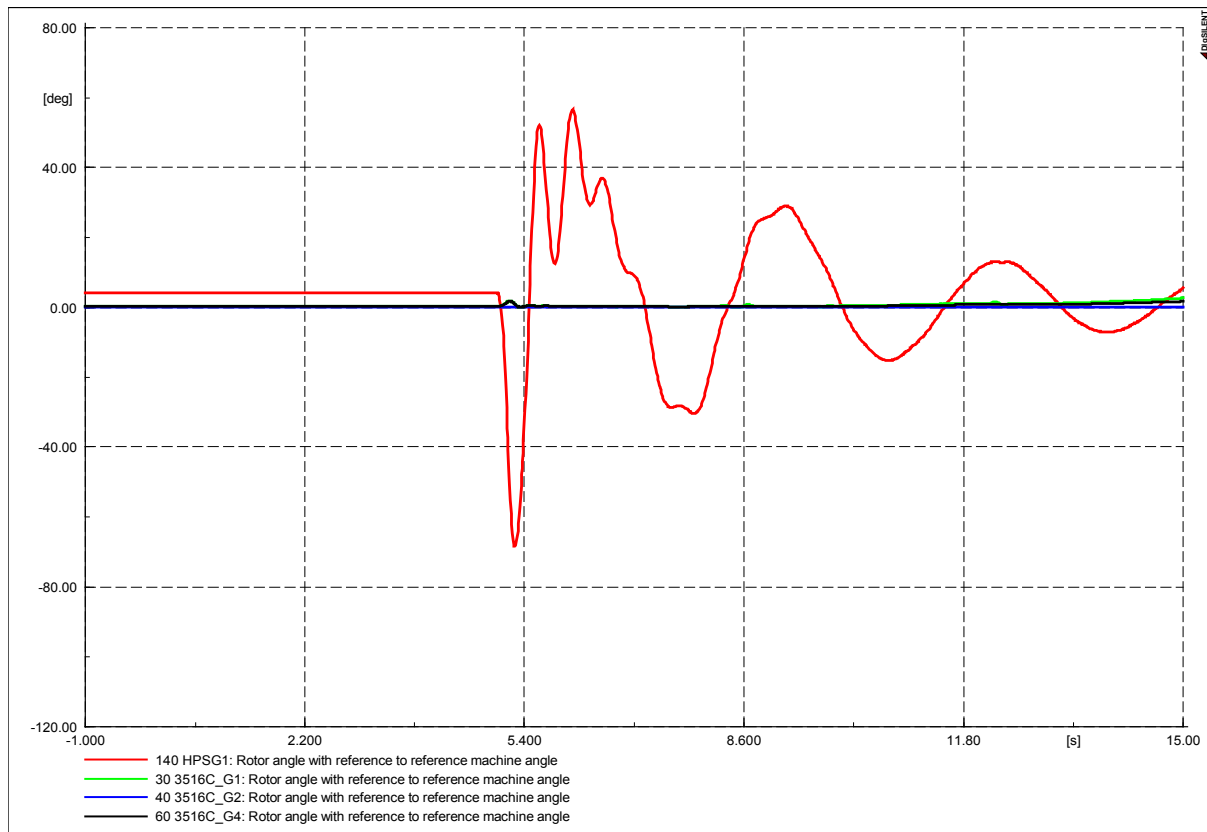
Tripping the Eastern feeder causes the frequency and voltage responses shown in Figure 2-5. The power transfer over the Eastern feeder from Nanpohnmal power plant before the trip is around 1,640 kW, accounting for approximately 30% of the power supply from the power plant.

**Figure 2-5: Voltage & frequency response to loss of Eastern feeder**

Similar to the Western feeder, the loss of the Eastern feeder causes the system frequency to exceed the 2% deviation momentarily before returning to within the allowable bandwidth and settling. The voltage remains within the limits for the duration of the study.

### ***Three phase fault (cleared after 150ms), trip Western feeder***

A three-phase fault was simulated at the power station busbar (NPP1BUS1). The fault was cleared within 150 ms at which point the Western feeder is tripped off. The voltage and rotor angle responses to these events are shown in Figure 2-6 and Figure 2-7 respectively.

**Figure 2-6: Voltage and frequency response to fault and subsequent feeder trip****Figure 2-7: 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 the Western feeder, the voltage recovers very quickly (within a few milliseconds), however it rises to almost 1.2 pu before returning to nominal value again. The operational generators in the system remain in synchronisation without pole-slip subsequent to the fault event however there is a significant rotor swing experienced at the hydro power station. System frequency oscillates outside the  $\pm 2\%$  bandwidth reaching 64 Hz and 56 Hz after fault inception and this does not settle to within the allowable limits within the study time period.

#### **Existing generation with PV switched on**

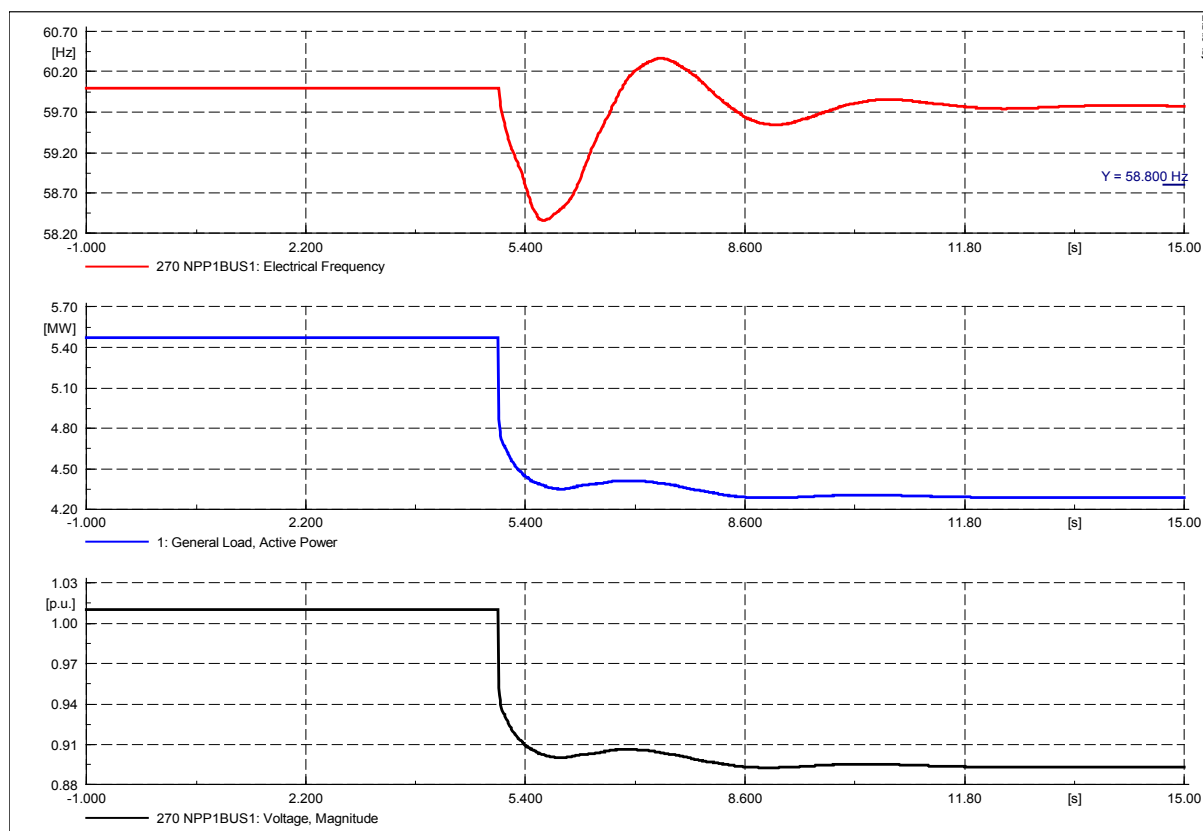
The studies above were repeated with the Pohnpei PV generation now connected to assess the impact of this generation on the stability of the system following a credible contingency. The generation mix for these studies is provided in Table 2-6. In this case, renewable generation output approximately accounts for 13.9% of total generation output and the available spinning reserve capacity is around 801 kW in the system.

**Table 2-6: Generation mix on Pohnpei with PV generation**

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel & Hydro	HPSG1	2	1	652.5	72.5	9.1%
	3516C_G1	3	1	1485	165	20.6%
	3516C_G2	3	1	1485	165	20.6%
	3516C_G4	3	1	1251.5	398.5	49.8%
	3516C_G5	3	1	0	0	0.0%
	3512_G2	3	1	0	0	0.0%
	VOLVO_G1	3	1	0	0	0.0%
	VOLVO_G2	3	1	0	0	0.0%
	VOLVO_G3	3	1	0	0	0.0%
	VOLVO_G4	3	0	0	0	0.0%
	<b>Sub-total</b>			<b>4874</b>	<b>801</b>	
Renewable	PALIKER (1)	1	1	16.0	0	0.0%
	PALIKER (2)	1	1	128.0	0	0.0%
	DAUSOKELE1	1	1	160.0	0	0.0%
	POHLOK	1	1	480.0	0	0.0%
	<b>Sub-total</b>			<b>784.0</b>	<b>0</b>	
				<b>5658</b>	<b>801</b>	<b>14.2%</b>

#### **Loss of largest generator**

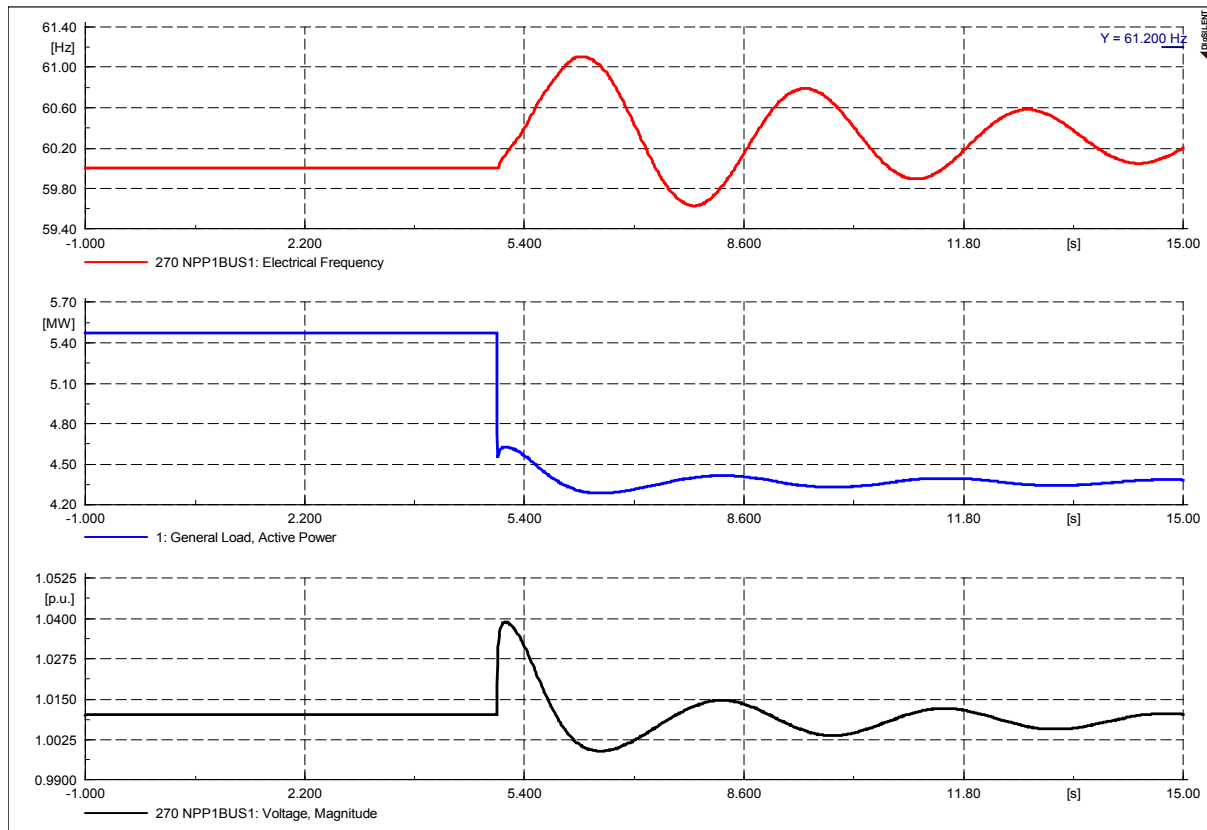
Diesel generator unit 3516C\_G1 is tripped in these studies as the largest generator on the system. The frequency and voltage response of the system are shown in Figure 2-8.

**Figure 2-8: Voltage & frequency response to loss of largest generator**

Upon the loss of the largest generator (operated at 1,485 kW), the system frequency drops to 58.3 Hz which is outside the 2% limit for frequency deviations, however this recovers quickly to around 59.75 Hz. The voltage drops to 0.89 pu and does not recover but remains steady at this value. This indicates that this generation dispatch scenario is unable to prevent system frequency and voltage drops outside their respective limits in the event where the largest generator is tripped. An additional diesel generator may need to be switched on to provide more spinning reserve and support system voltage recovery.

### **Western feeder trip**

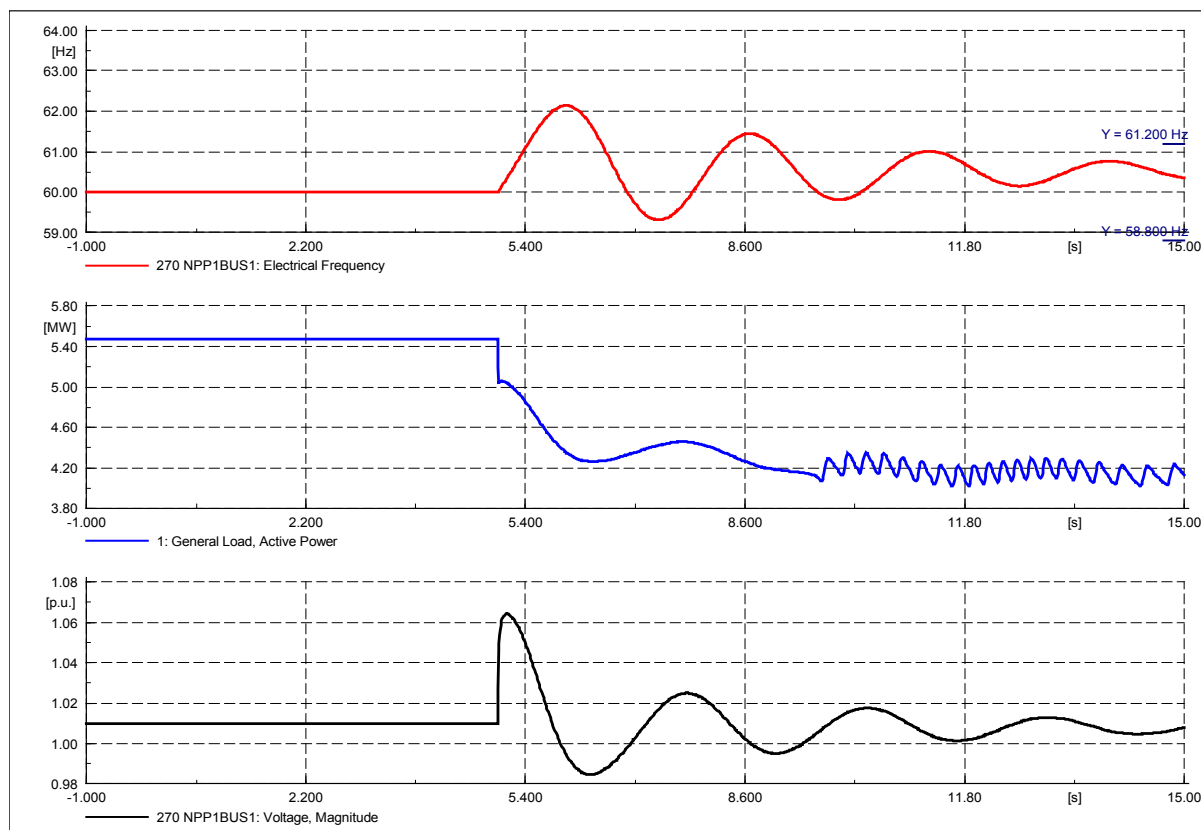
Tripping the Western feeder causes the frequency and voltage responses shown in Figure 2-9.

**Figure 2-9: Voltage & frequency response to loss of Western feeder**

The frequency increases slightly upon the loss of the Western feeder but it remains within the acceptable bandwidth for the duration of the study. The voltage peaks at 1.04 pu but also remains within limits for the duration of the study.

### ***Eastern feeder trip***

Tripping the Eastern feeder causes the frequency and voltage responses shown in Figure 2-10.

**Figure 2-10: Voltage & frequency response to loss of Eastern feeder**

The loss of the Eastern feeder causes the system frequency to exceed the 2% deviation momentarily before returning to within the allowable bandwidth and settling. The voltage peaks at 1.06 pu but also remains within limits for the duration of the study.

### ***Three phase fault (cleared after 150ms), trip Western feeder***

A three-phase fault was simulated at the power station busbar (NPP1BUS1). The fault was cleared within 150 ms at which point the Western feeder is tripped off. The voltage and rotor angle responses to these events are shown in Figure 2-11 and Figure 2-12 respectively.

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

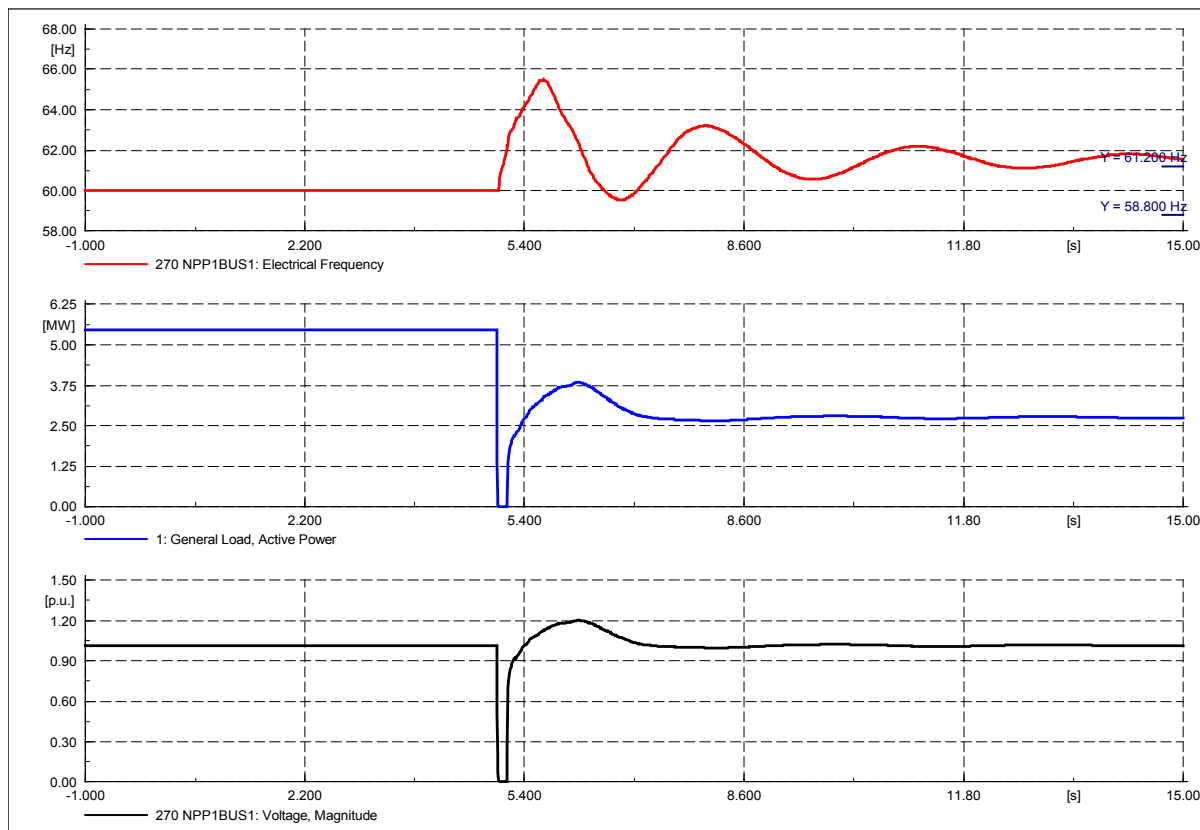
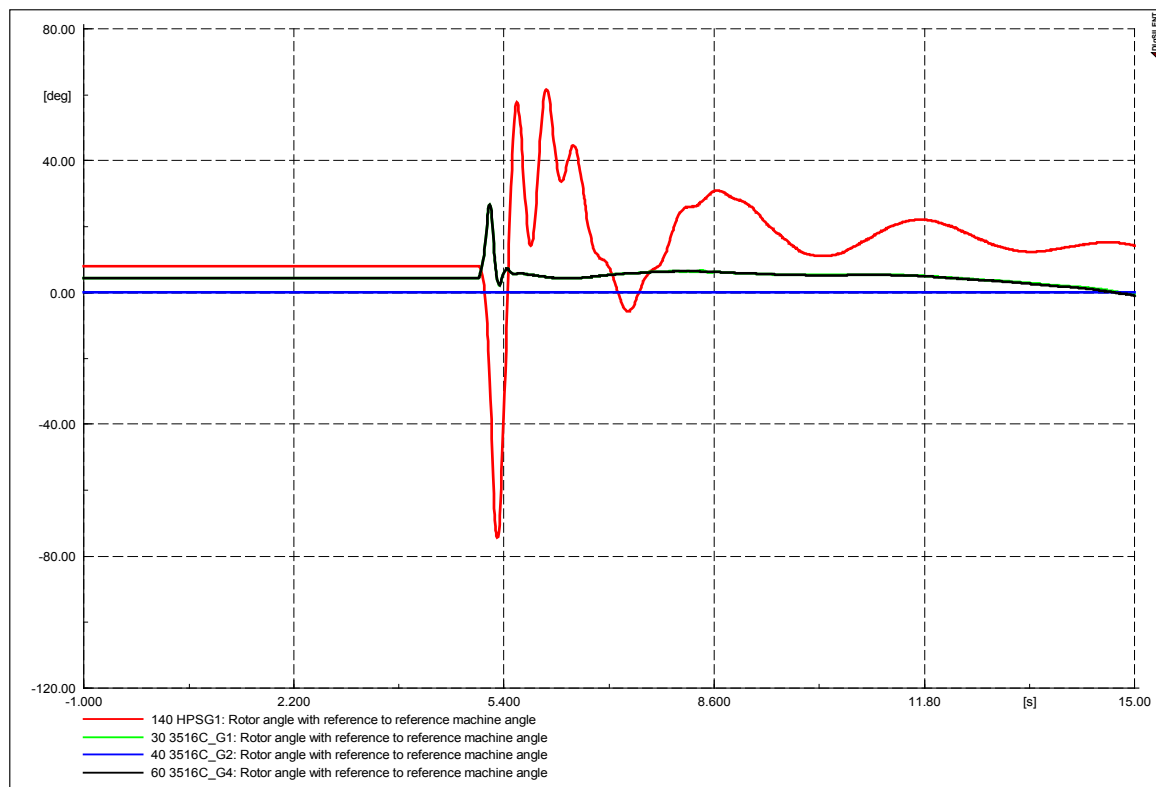


Figure 2-12: Rotor angle response to fault and subsequent feeder trip



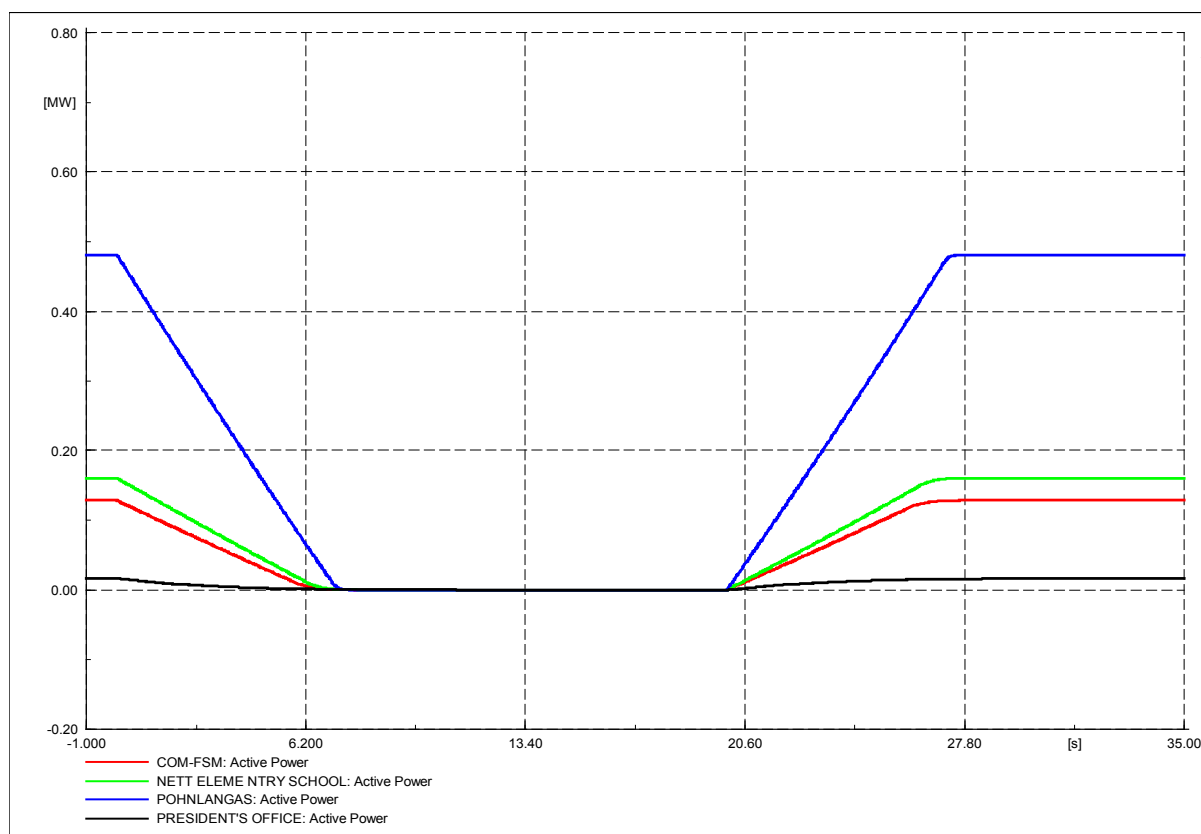


Immediately after the fault, the voltage at the monitored bus (substation busbar) drops to 0 pu. Upon the tripping of the Western feeder, the voltage recovers very quickly (within a few milliseconds), however it rises to almost 1.2 pu before returning to nominal value again. The operational generators in the system remain in synchronisation without pole-slip subsequent to the fault event however there is a significant rotor swing experienced at the hydro power station. System frequency oscillates outside the  $\pm 2\%$  bandwidth reaching a high of 65 Hz after fault inception and this does not settle to within the allowable limits within the study time period.

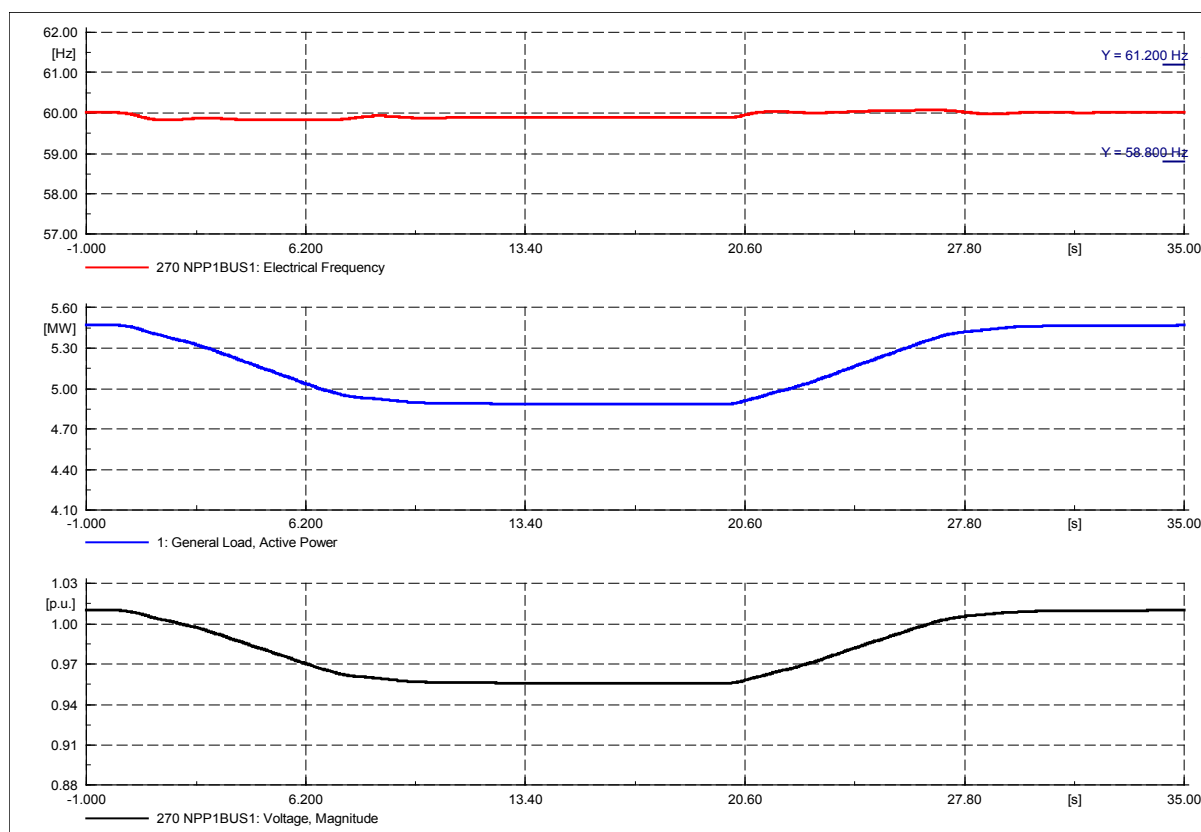
#### **Reduction/increase of PV output to/from maximum/0MW (AVR off)**

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 PV generation is not set to maximum output because maximum demand is so low and the diesel generation is operating at minimum output; the PV generation cannot exceed 80%. The generation mix assumed in this case is that presented in Table 2-6. The PV output is shown in Figure 2-13.

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



The voltage and frequency responses are shown in Figure 2-14.

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

As the MW output of the PV generators decreases, the frequency decreases minimally and stays around 60 Hz for the duration of the study. The voltage Reduces to 0.95 pu and ramps up again to 1.01 pu as the PV generation increases back to 80% output. The simulation results indicate that in this operational scenario, the system is capable of withstanding the drop and rise of PV generation within the given kW capacity and kW output level.

### ***Existing generation (varied dispatch) with PV generation***

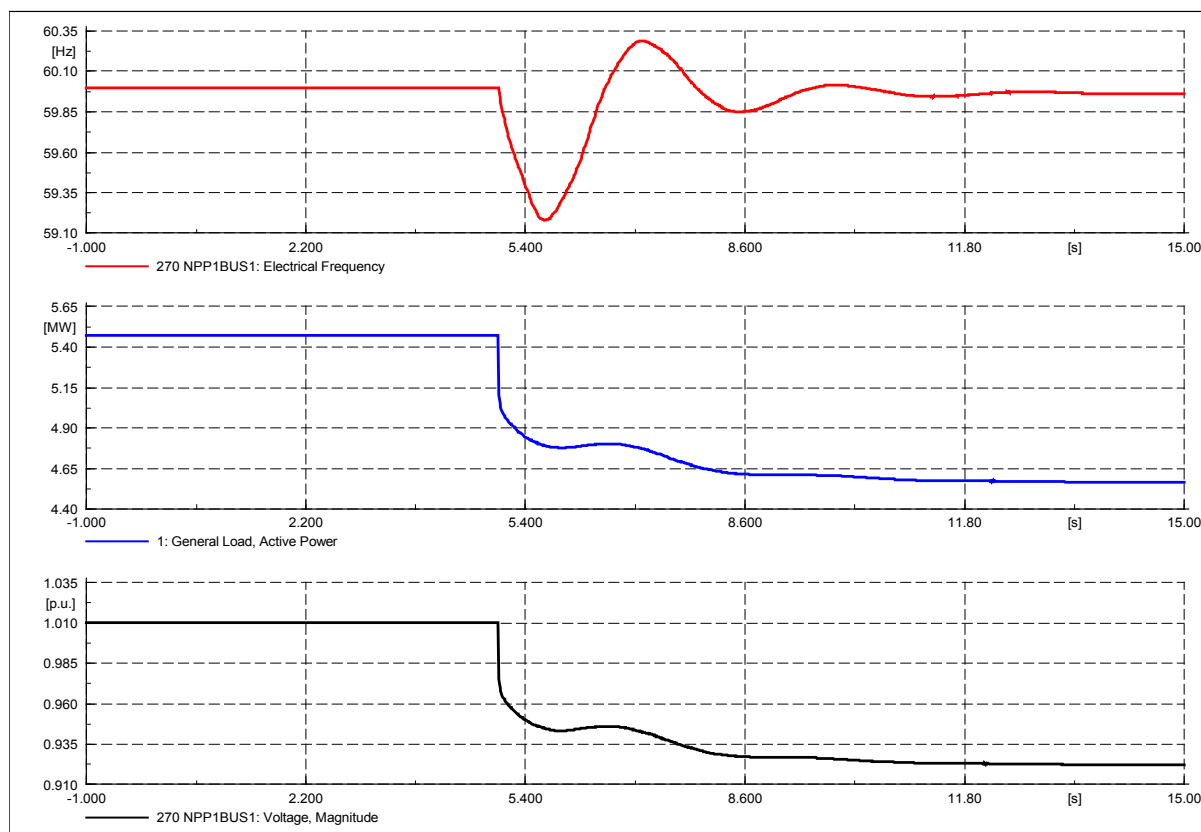
From the studies above with the conventional generation dispatch as described, the stability of the Pohnpei system is not guaranteed with the frequency deviating to outside the 2% limit in many cases after credible contingency events. As such, the generation dispatch has been varied to that shown in Table 2-7. This dispatch has PV generation operating at 80% and also has more diesel generation operating online at lower outputs which provides more spinning reserve. The stability studies were repeated with the updated generation dispatch to assess the impact on stability on those cases where there were issues of instability. In this case, the available spinning reserve capacity is around 3,122.5 kW in the system.

**Table 2-7: Updated generation mix on Pohnpei with PV generation**

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel & Hydro	HPSG1	2	1	540	185	5.9%
	3516C_G1	3	1	1000	650	20.8%
	3516C_G2	3	1	907.5	742.5	23.8%
	3516C_G4	3	1	907.5	742.5	23.8%
	3516C_G5	3	1	907.5	742.5	23.8%
	3512_G2	3	1	540	60	1.9%
	VOLVO_G1	3	1	0	0	0.0%
	VOLVO_G2	3	1	0	0	0.0%
	VOLVO_G3	3	1	0	0	0.0%
	VOLVO_G4	3	0	0	0	0.0%
	<b>Sub-total</b>			4802.5	3122.5	
Renewable	PALIKER (1)	1	1	16.0	0.0	0.0%
	PALIKER (2)	1	1	128.0	0.0	0.0%
	DAUSOKELE1	1	1	160.0	0.0	0.0%
	POHLOK	1	1	480.0	0.0	0.0%
	<b>Sub-total</b>			784.0	0.0	
				5586.5	3122.5	55.2%

**Loss of largest generator**

Diesel generator unit 3516C\_G1 (operated at 1,000 kW) is tripped in these studies as the largest generator on the system. The frequency and voltage response of the system are shown in Figure 2-15.

**Figure 2-15: Voltage & frequency response to loss of largest generator**

The frequency response of the system with this generation dispatch portfolio is improved and the frequency remains within the limits for the duration of the study. The voltage reduces to 0.92 pu following the event and stabilises there. This response is improved from the previous generation dispatch in Table 2-6 and no limits are exceeded.

## 2.2.4 Increasing penetration of VRE

There are plans to increase the penetration of VRE on the Pohnpei network, primarily from solar PV however, detailed generation expansion planning information was not available. As such, the Pohnpei system has been tested with different levels of additional PV penetrations and a number of studies have been performed to assess the capability of the network to accommodate this higher level of renewable generation e.g. 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.

### 2.2.4.1 Additional 1200 kW of solar PV generation

The following sections present the results which highlight the ability of the Pohnpei network to accommodate 1,200 kW of additional PV generation. The generation mix assumed for these studies is listed in Table 2-8 where the typical conventional generation dispatch is assumed and the existing PV generation on the system operating at 80%. In this case, the load demand of the system is assumed to be 6,018 kW, 10% above the existing maximum load demand level, and renewable generation output accounts for 32% of total generation output with available spinning reserve of 1,436 kW in the system.

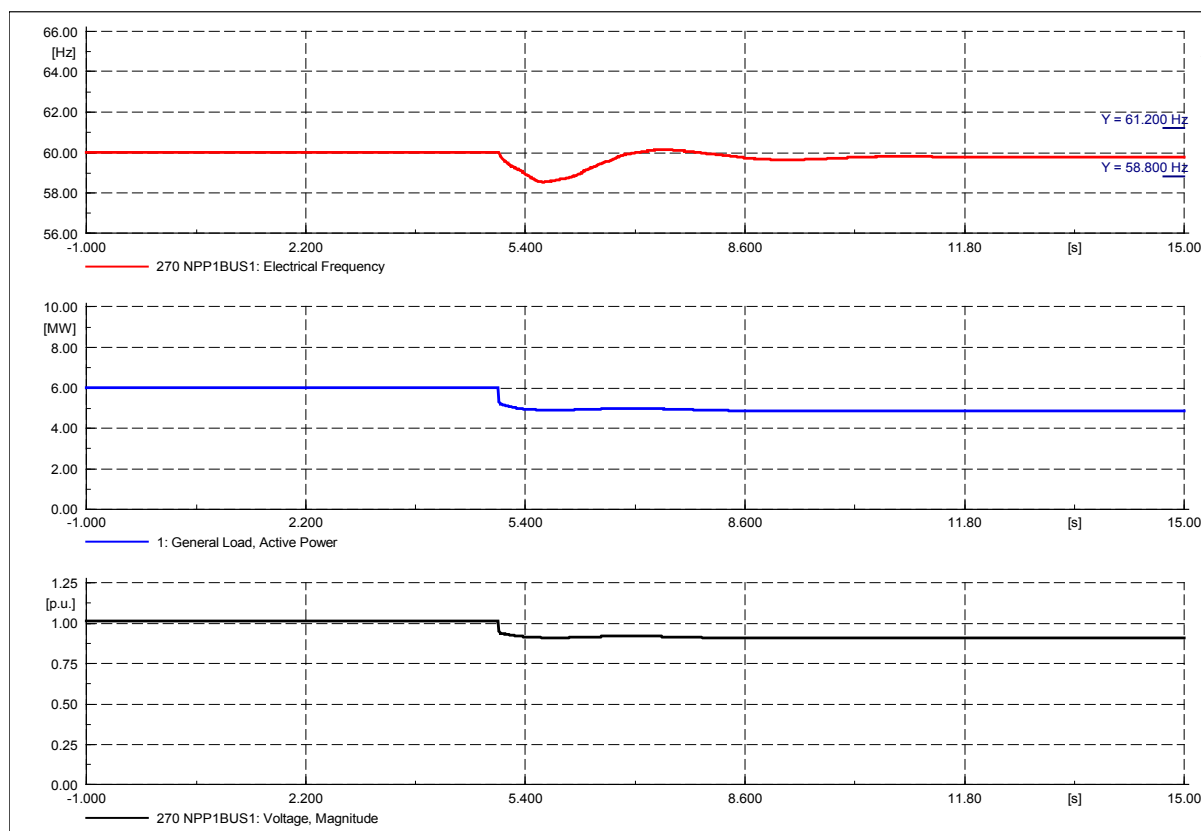
**Table 2-8: Generation mix on Pohnpei with additional 1200kW PV generation**

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel & Hydro	HPSG1	2	1	652.5	72.5	5.0%
	3516C_G1	3	1	1485	165	11.5%
	3516C_G2	3	1	1485	165	11.5%
	3516C_G4	3	1	616.5	1033.5	72.0%
	3516C_G5	3	1	0	0	0.0%
	3512_G2	3	1	0	0	0.0%
	Peaker_G1	3	1	0	0	0.0%
	Peaker_G2	3	1	0	0	0.0%
	VOLVO_G1	3	1	0	0	0.0%
	VOLVO_G2	3	1	0	0	0.0%
	VOLVO_G3	3	1	0	0	0.0%
	VOLVO_G4	3	0	0	0	0.0%
	<b>Sub-total</b>			<b>4239.0</b>	<b>1436.0</b>	
Renewable	PALIKER (1)	1	1	16.0	0.0	0.0%
	PALIKER (2)	1	1	128.0	0.0	0.0%
	DAUSOKELE1	1	1	160.0	0.0	0.0%
	POHLOK	1	1	480.0	0.0	0.0%
	Future	1	1	1200.0	0.0	0.0%
	<b>Sub-total</b>			<b>1984.0</b>	<b>0.0</b>	
				<b>6223</b>	<b>1436</b>	<b>23.1%</b>

**Loss of largest generator**

Diesel generator unit 3516C\_G1 (operated at 1,485 kW) is tripped in these studies as the largest generator on the system. The frequency and voltage response of the system are shown in Figure 2-15.

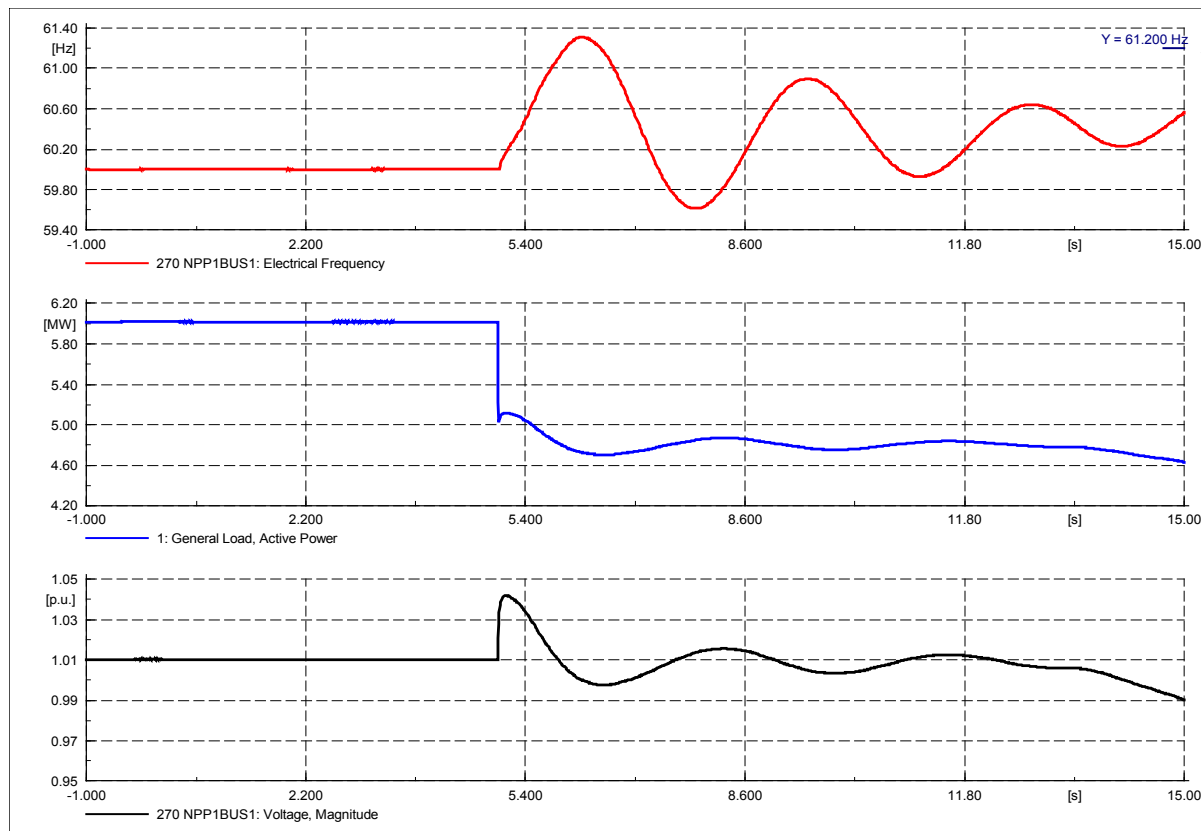


**Figure 2-16: Voltage & frequency response to loss of largest generator**

Upon the loss of the largest generator, the system frequency drops to 58.7 Hz which is marginally outside the 2% limit for frequency deviations, however this recovers quickly and there are no oscillations in the response. The voltage drops to 0.92 pu and remains steady at this value.

### ***Western feeder trip***

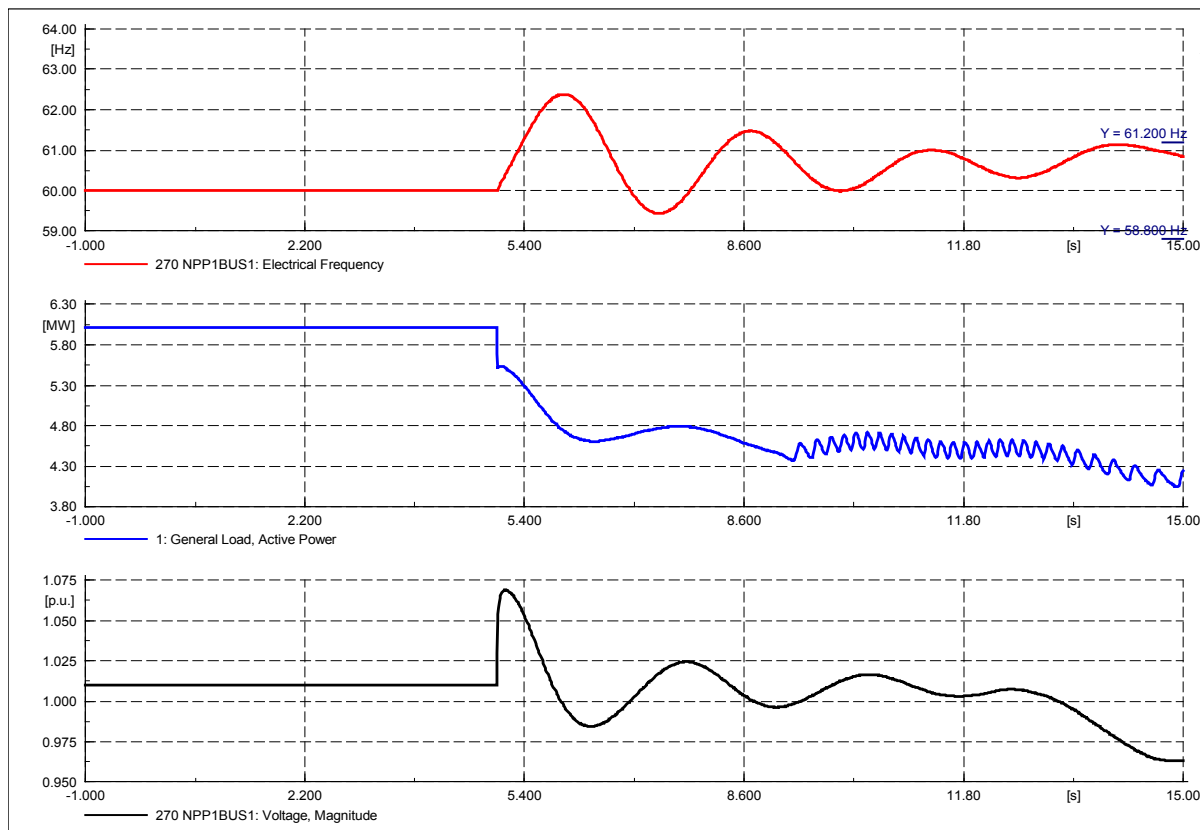
Tripping the Western feeder causes the frequency and voltage responses shown in Figure 2-17.

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

The frequency increases upon the loss of the Western feeder and marginally exceeds the limit of 61.2 Hz but it reduces quickly and remains within the acceptable bandwidth for the duration of the study. The voltage peaks at 1.04 pu but also remains within limits for the duration of the study.

#### **Eastern feeder trip**

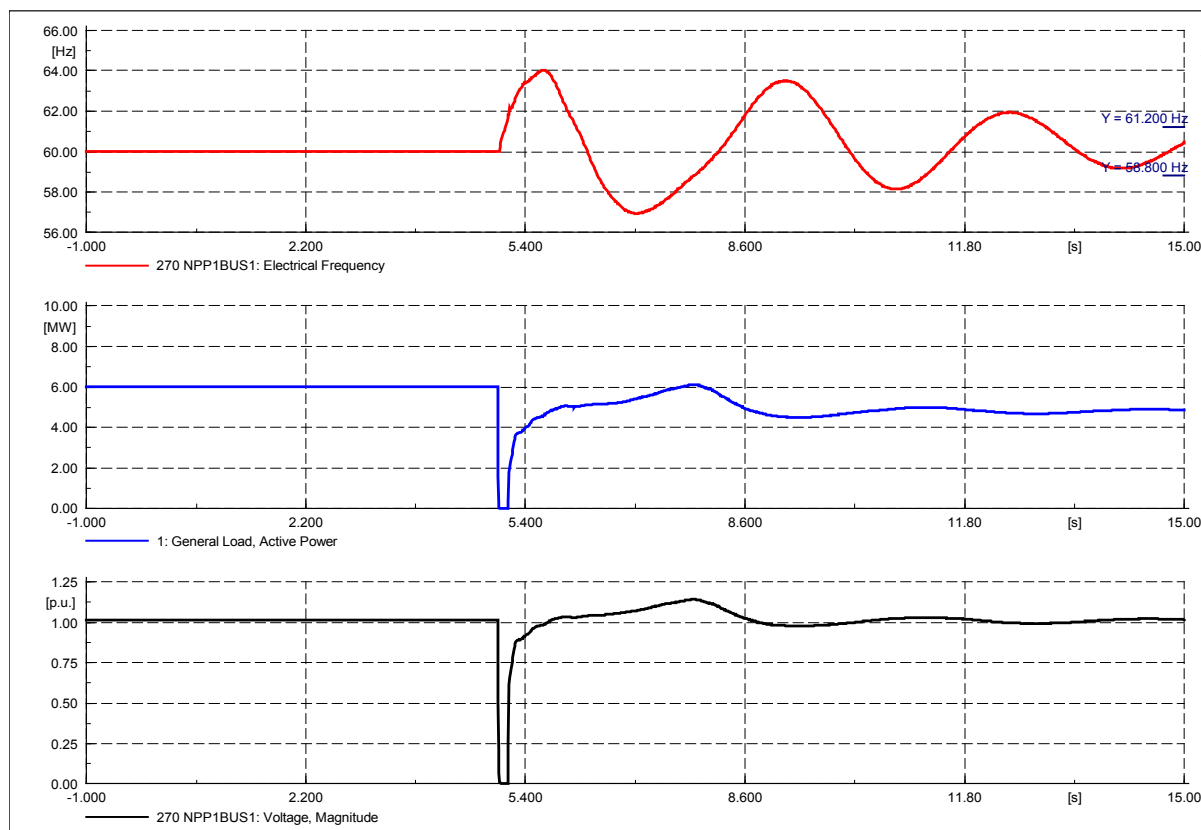
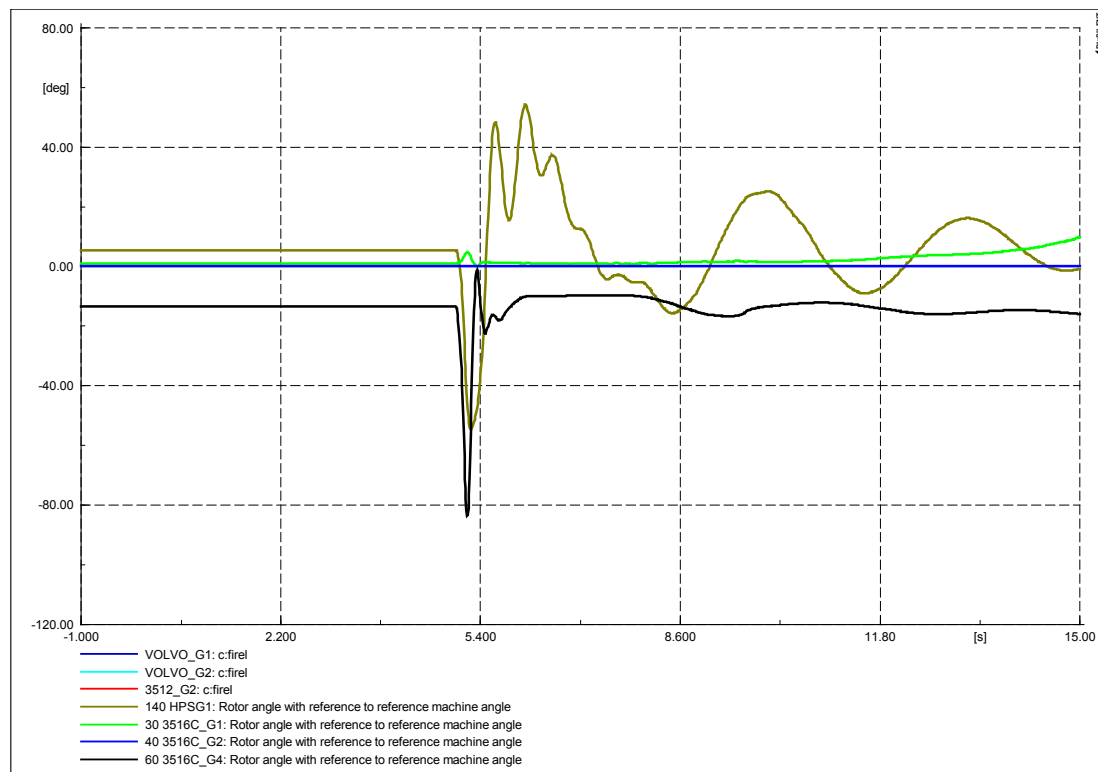
Tripping the Eastern feeder causes the frequency and voltage responses shown in Figure 2-18.

**Figure 2-18: Voltage & frequency response to loss of Eastern feeder**

The loss of the Eastern feeder causes the system frequency to exceed the 2% deviation limit before returning to within the allowable bandwidth and settling. The voltage peaks at 1.07 pu but also remains within limits for the duration of the study.

### ***Three phase fault (cleared after 150ms), trip Western feeder***

A three-phase fault was simulated at the power station busbar (NPP1BUS1). The fault was cleared within 150 ms at which point the Western feeder is tripped off. The voltage and rotor angle responses to these events are shown in Figure 2-19 and Figure 2-20 respectively.

**Figure 2-19: Voltage and frequency response to fault and subsequent feeder trip****Figure 2-20: Rotor angle response to fault and subsequent feeder trip**

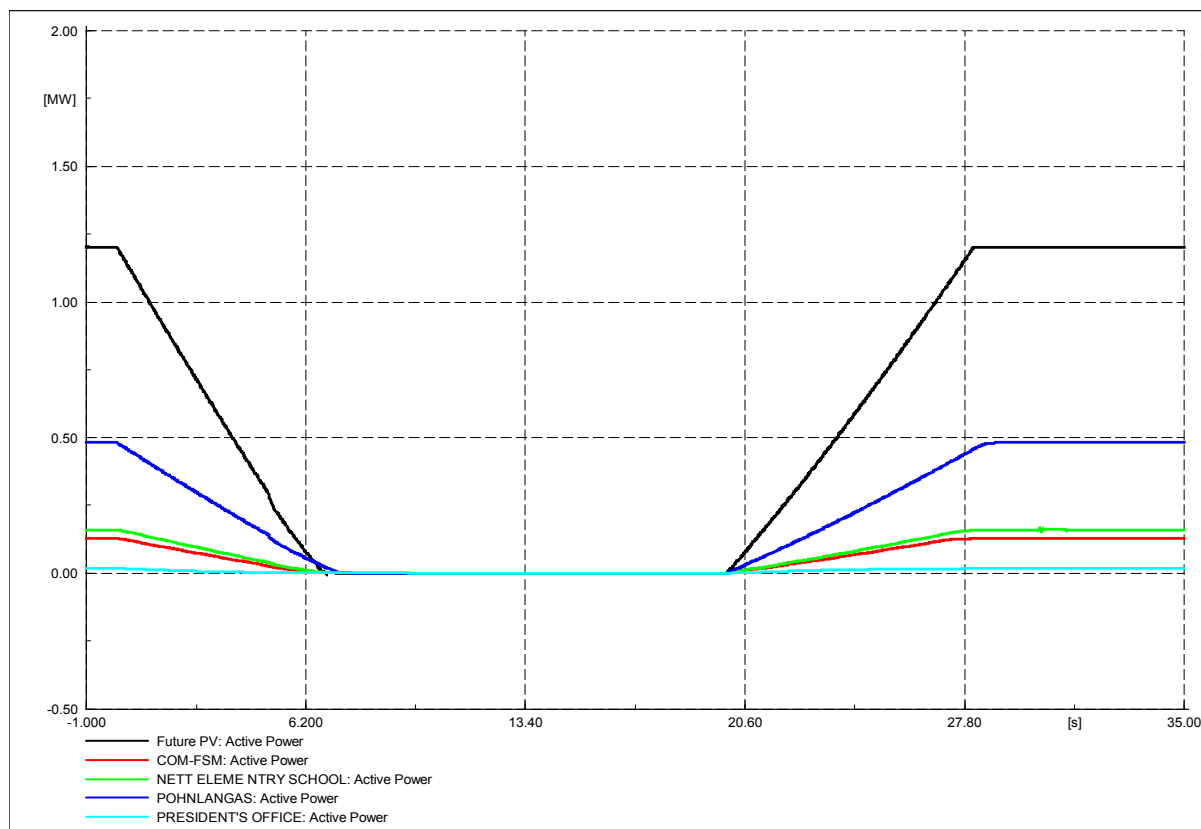
Immediately after the fault, the voltage at the monitored bus (substation busbar) drops to 0 pu. Upon the tripping of the Western feeder, the voltage recovers very quickly (within a few milliseconds) and rises to around 1.1 pu before returning to nominal value again. The operational generators in the system

remain in synchronisation without pole-slip subsequent to the fault event however there is a significant rotor swing experienced at the hydro power station and at G4. System frequency oscillates quite significantly outside the  $\pm 2\%$  bandwidth reaching a high of 64 Hz and a low of 57 Hz after fault inception.

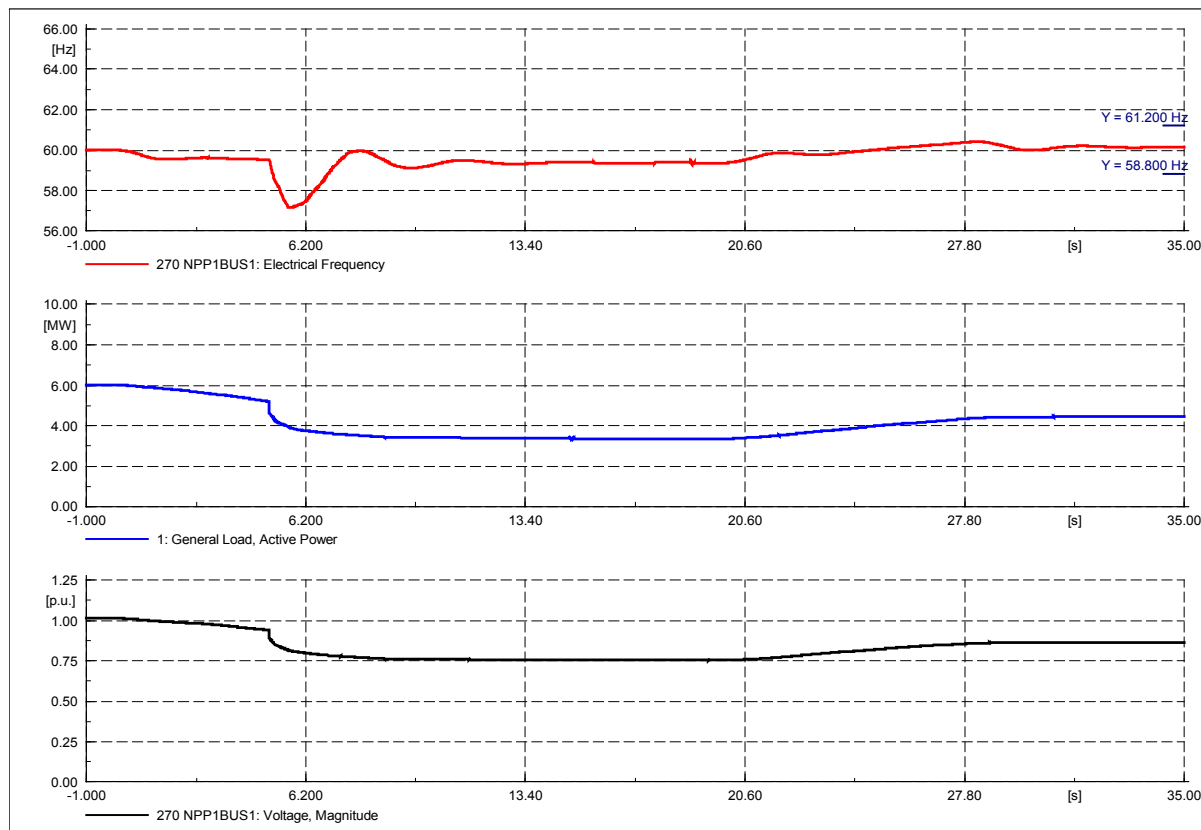
#### **Reduction/increase of PV output to/from maximum/0MW (AVR off)**

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 new PV generation is set to maximum output of 1,200 kW. The PV output is shown in Figure 2-21.

**Figure 2-21: PV MW output of all sites on Pohnpei**



The voltage and frequency responses are shown in Figure 2-22.

**Figure 2-22: Voltage and frequency response to changing PV MW output**

As the MW output of the PV generators decreases, the frequency decreases sharply to approximately 57 Hz, recovers then stays around 60 Hz for the duration of the study. The voltage reduces to 0.75 pu and voltage collapse in the system could potentially be the case when the PV generators ramp down. The simulation results indicate that in this operational scenario, the system is incapable of withstanding the drop and rise of PV generation within the given kW capacity and kW output level.

#### 2.2.4.2 Additional 1200 kW of solar PV generation – Updated generation dispatch

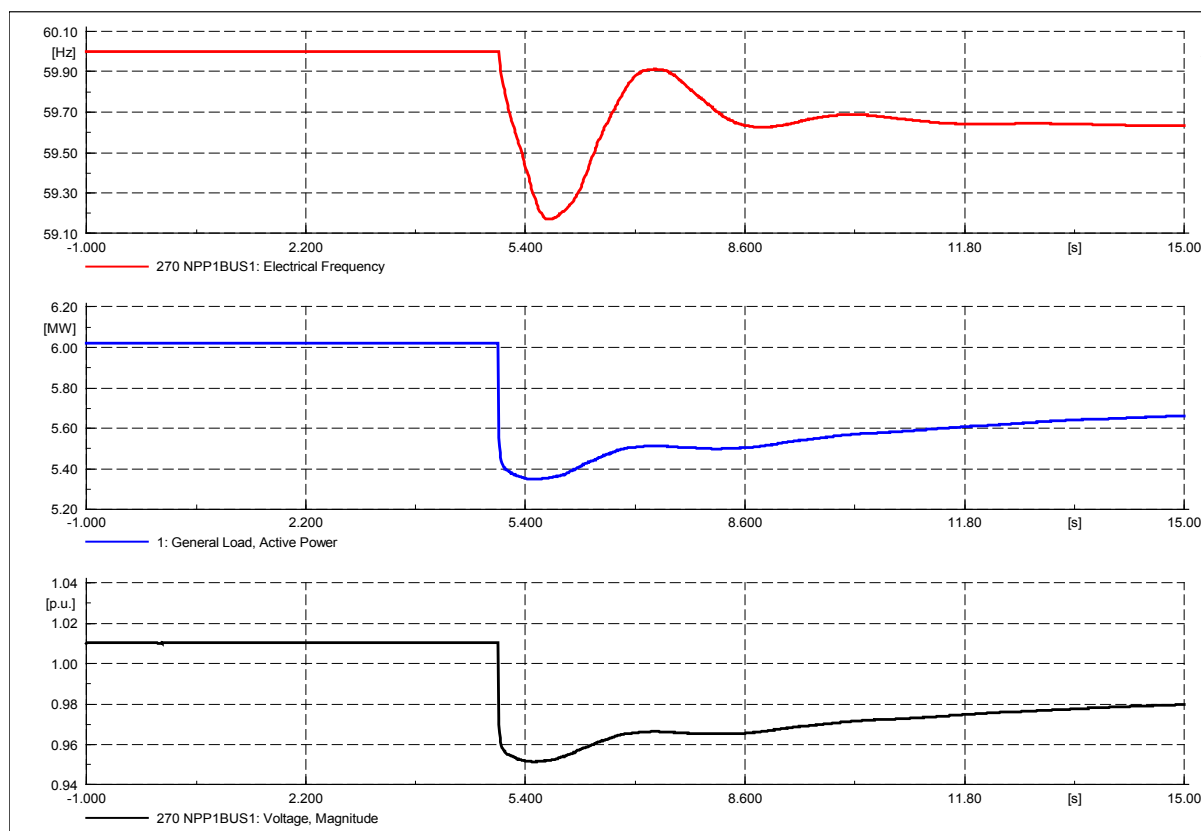
Similar to the response of the system with the existing generation portfolio, there are large frequency deviations, and in some cases, the potential for voltage collapse when only three diesel generators and the hydro generator are online. As such, the following sections present the results of studies with 1,200kW of additional PV generation with an updated conventional generation dispatch to provide more spinning reserve and system inertia. The generation mix assumed for these studies is listed in Table 2-9.

**Table 2-9: Updated generation mix on Pohnpei with additional 1200kW PV generation**

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel & Hydro	HPSG1	2	1	540	185	5.0%
	3516C_G1	3	1	1000	650	17.6%
	3516C_G2	3	1	825	825	22.4%
	3516C_G4	3	1	825	825	22.4%
	3516C_G5	3	1	825	825	22.4%
	3512_G2	3	1	224	376	10.2%
	Peaker_G1	3	1	0	0	0.0%
	Peaker_G2	3	1	0	0	0.0%
	VOLVO_G1	3	1	0	0	0.0%
	VOLVO_G2	3	1	0	0	0.0%
	VOLVO_G3	3	1	0	0	0.0%
	VOLVO_G4	3	0	0	0	0.0%
	<b>Sub-total</b>			<b>4239.0</b>	<b>3686.0</b>	
Renewable	PALIKER (1)	1	1	16.0	0.0	0.0%
	PALIKER (2)	1	1	128.0	0.0	0.0%
	DAUSOKELE1	1	1	160.0	0.0	0.0%
	POHLOK	1	1	480.0	0.0	0.0%
	Future	1	1	1200.0	0.0	0.0%
	<b>Sub-total</b>			<b>1984.0</b>	<b>0.0</b>	
				<b>6223</b>	<b>3686</b>	59.2%

**Loss of largest generator**

Diesel generator unit 3516C\_G1 (operated at 1,000 kW) is tripped in these studies as the largest generator on the system. The frequency and voltage response of the system are shown in Figure 2-23.

**Figure 2-23: Voltage & frequency response to loss of largest generator**

Upon the loss of the largest generator, the system frequency drops to 59.2 Hz which is within the operational limits. The voltage drops to 0.95 pu and increases steadily up to 0.98 pu.

### ***Three phase fault (cleared after 150ms), trip Western feeder***

A three-phase fault was simulated at the power station busbar (NPP1BUS1). The fault was cleared within 150 ms at which point the Western feeder is tripped off. The voltage and rotor angle responses to these events are shown in Figure 2-24 and Figure 2-25 respectively.



Figure 2-24: Voltage and frequency response to fault and subsequent feeder trip

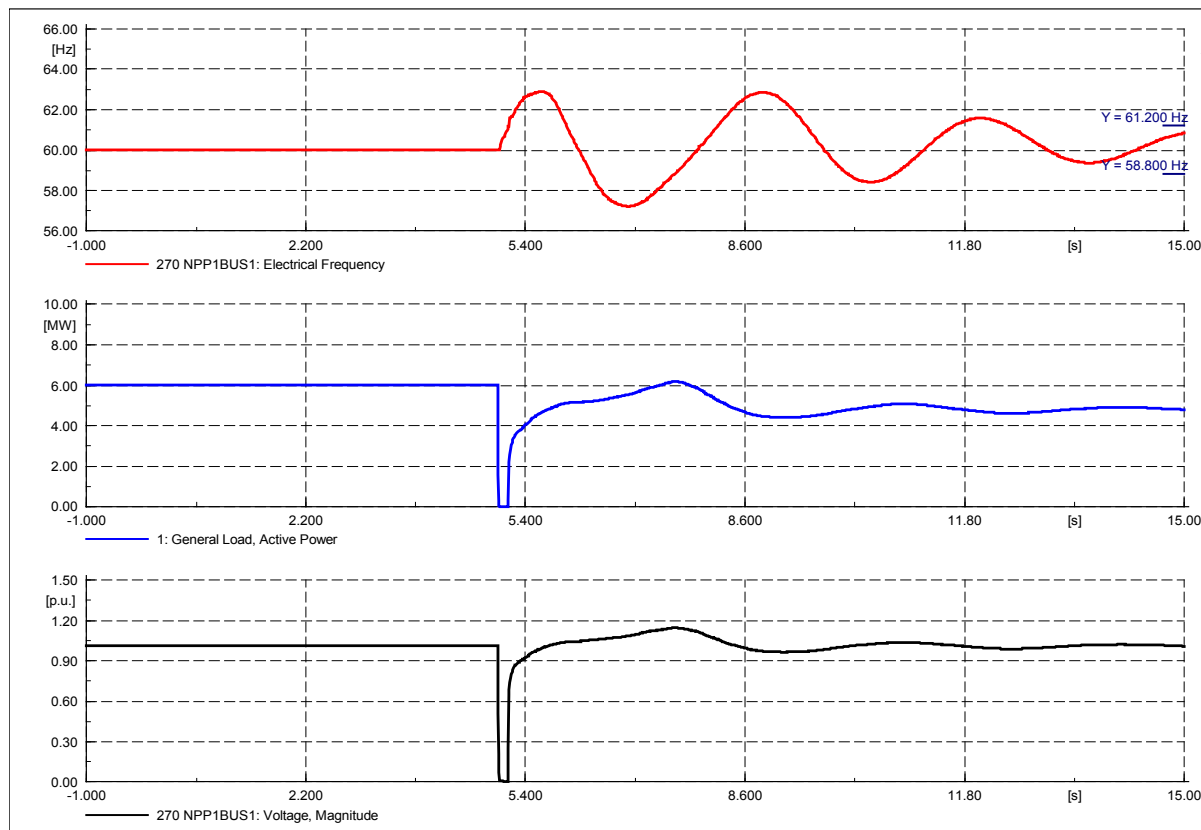
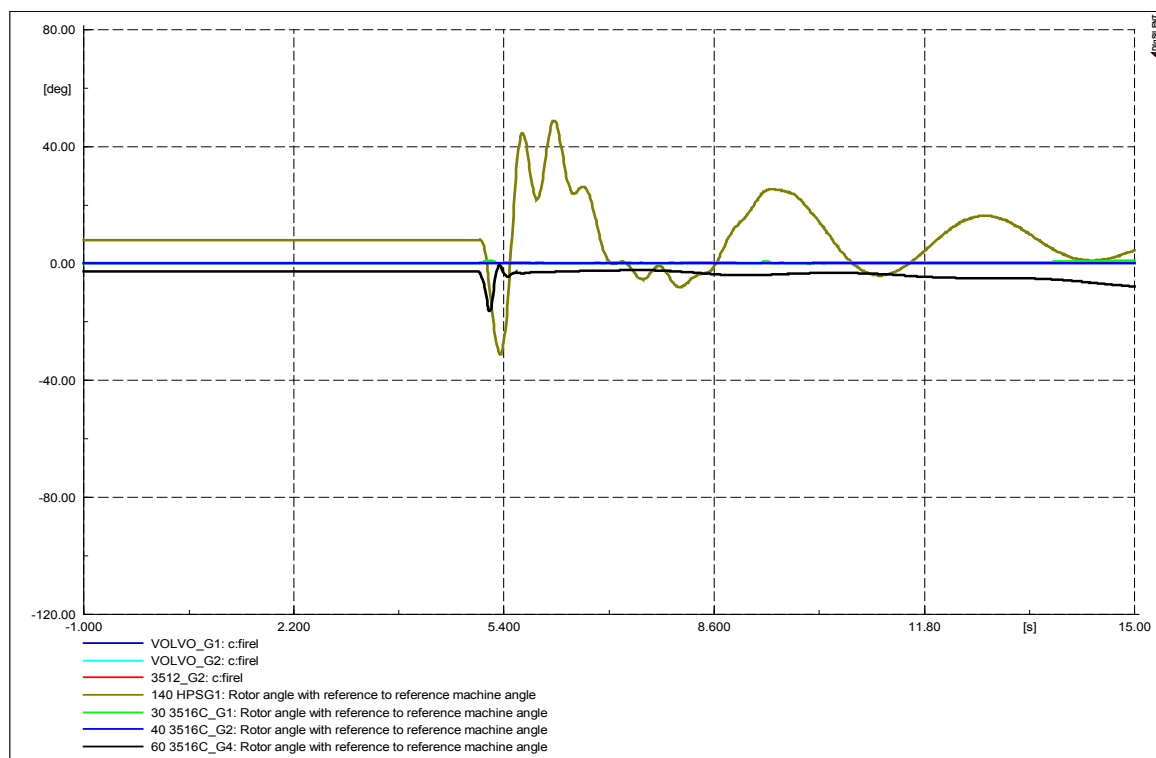


Figure 2-25: Rotor angle response to fault and subsequent feeder trip

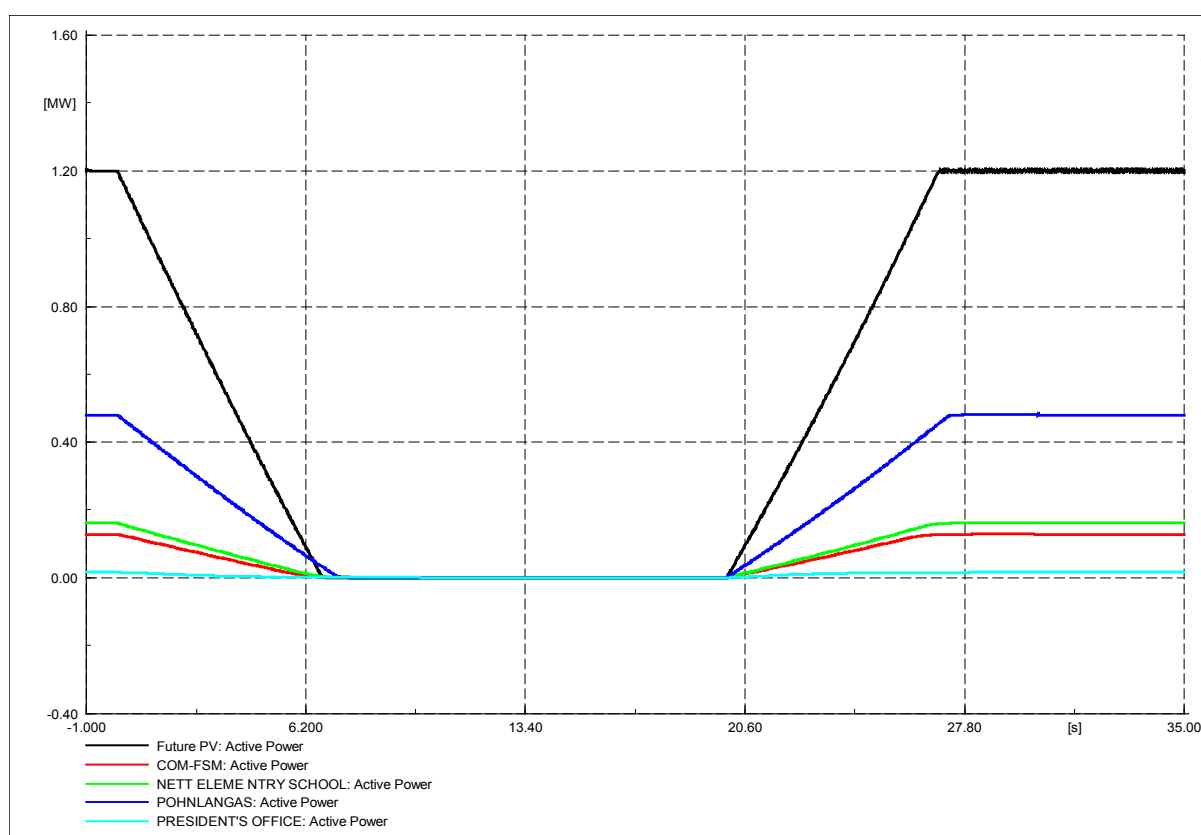


Immediately after the fault, the voltage at the monitored bus (substation busbar) drops to 0 pu. Upon the tripping of the Western feeder, the voltage recovers very quickly (within a few milliseconds) and rises to around 1.1 pu before returning to nominal value again. The operational generators in the system remain in synchronisation without pole-slip subsequent to the fault event however there is some rotor swing experienced at the hydro power station. System frequency oscillates quite significantly outside the  $\pm 2\%$  bandwidth reaching a high of 63 Hz and a low of 57 Hz after fault inception.

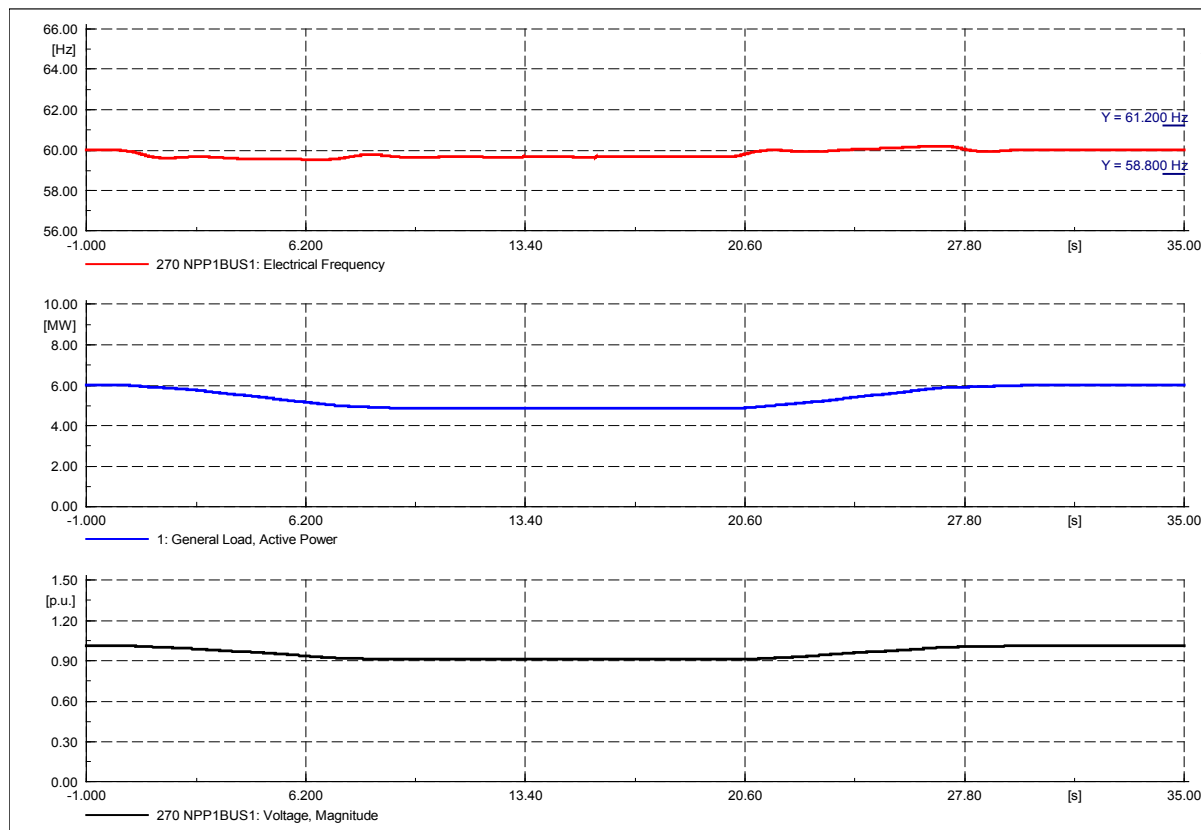
#### **Reduction/increase of PV output to/from maximum/0MW (AVR off)**

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 new PV generation is set to maximum output of 1,200 kW. The PV output is shown in Figure 2-26.

**Figure 2-26: PV MW output of all sites on Pohnpei**



The voltage and frequency responses are shown in Figure 2-27.

**Figure 2-27: Voltage and frequency response to changing PV MW output**

As the MW output of the PV generators decreases, the frequency decreases marginally and then fluctuates slightly around 60 Hz for the duration of the study. The voltage reduces to 0.9 pu when the PV generators ramp down which is just within the  $\pm 10\%$  limit for voltage. The simulation results indicate that with more conventional generators on line, the system is basically capable of withstanding the drop and rise of PV generation within the given kW capacity and kW output level.

#### 2.2.4.3 Additional 2400 kW of solar PV generation

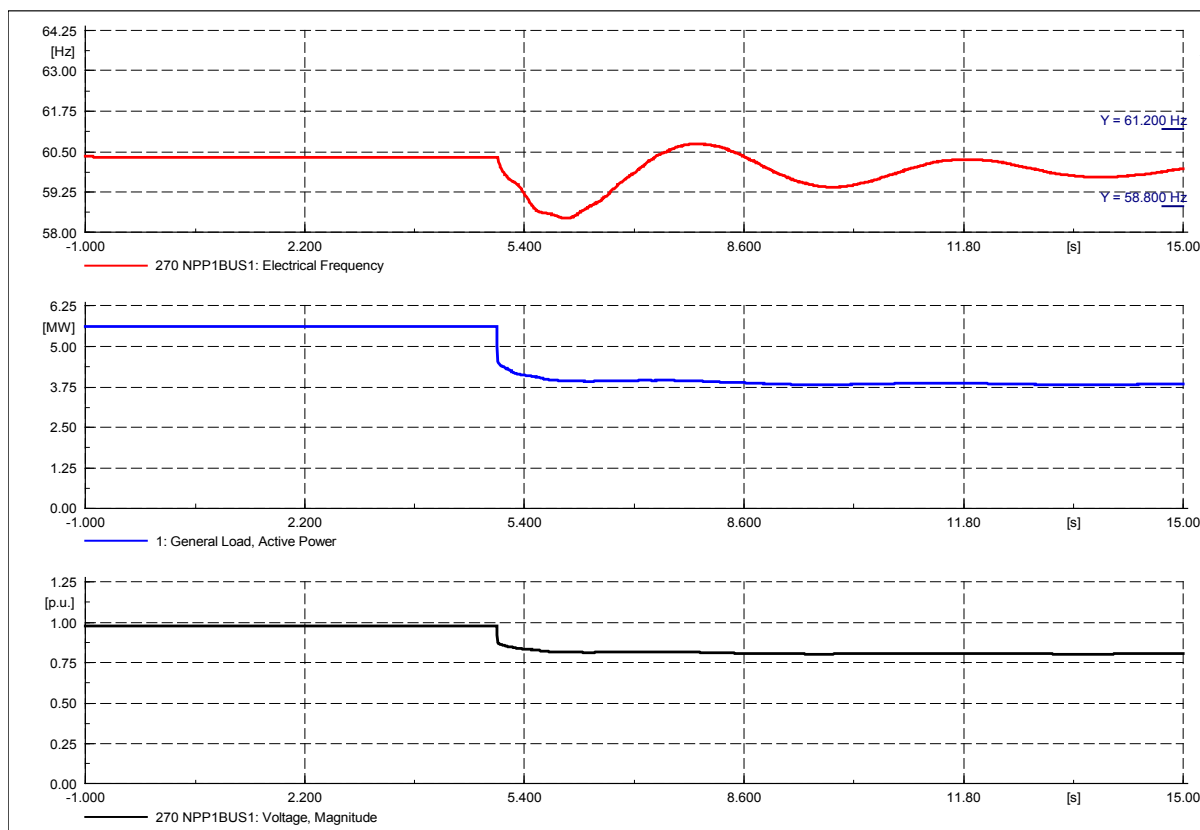
The following sections present the results which highlight the ability of the Pohnpei network to accommodate 2,400 kW of additional PV generation. The generation mix assumed for these studies is listed in Table 2-10 where the typical conventional generation dispatch is assumed and the existing PV generation on the system operating at 80%. In this case, renewable generation output accounts for 51% of total generation output with available spinning reserve of 986 kW in the system.

**Table 2-10: Generation mix on Pohnpei with additional 2400kW PV generation**

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel & Hydro	HPSG1	2	1	652.5	72.5	7.4%
	3516C_G1	3	1	1485	165	16.7%
	3516C_G2	3	1	901.5	748.5	75.9%
	3516C_G4	3	1	0	0	0.0%
	3516C_G5	3	1	0	0	0.0%
	3512_G2	3	1	0	0	0.0%
	Peaker_G1	3	1	0	0	0.0%
	Peaker_G2	3	1	0	0	0.0%
	VOLVO_G1	3	1	0	0	0.0%
	VOLVO_G2	3	1	0	0	0.0%
	VOLVO_G3	3	1	0	0	0.0%
	VOLVO_G4	3	1	0	0	0.0%
	<b>Sub-total</b>			<b>3039.0</b>	<b>986.0</b>	
Renewable	PALIKER (1)	1	1	16.0	0.0	0.0%
	PALIKER (2)	1	1	128.0	0.0	0.0%
	DAUSOKELE1	1	1	160.0	0.0	0.0%
	POHLOK	1	1	480.0	0.0	0.0%
	Future	1	1	2400.0	0.0	0.0%
	<b>Sub-total</b>			<b>3184.0</b>	<b>0.0</b>	
				<b>6223</b>	<b>986</b>	15.8%

**Loss of largest generator**

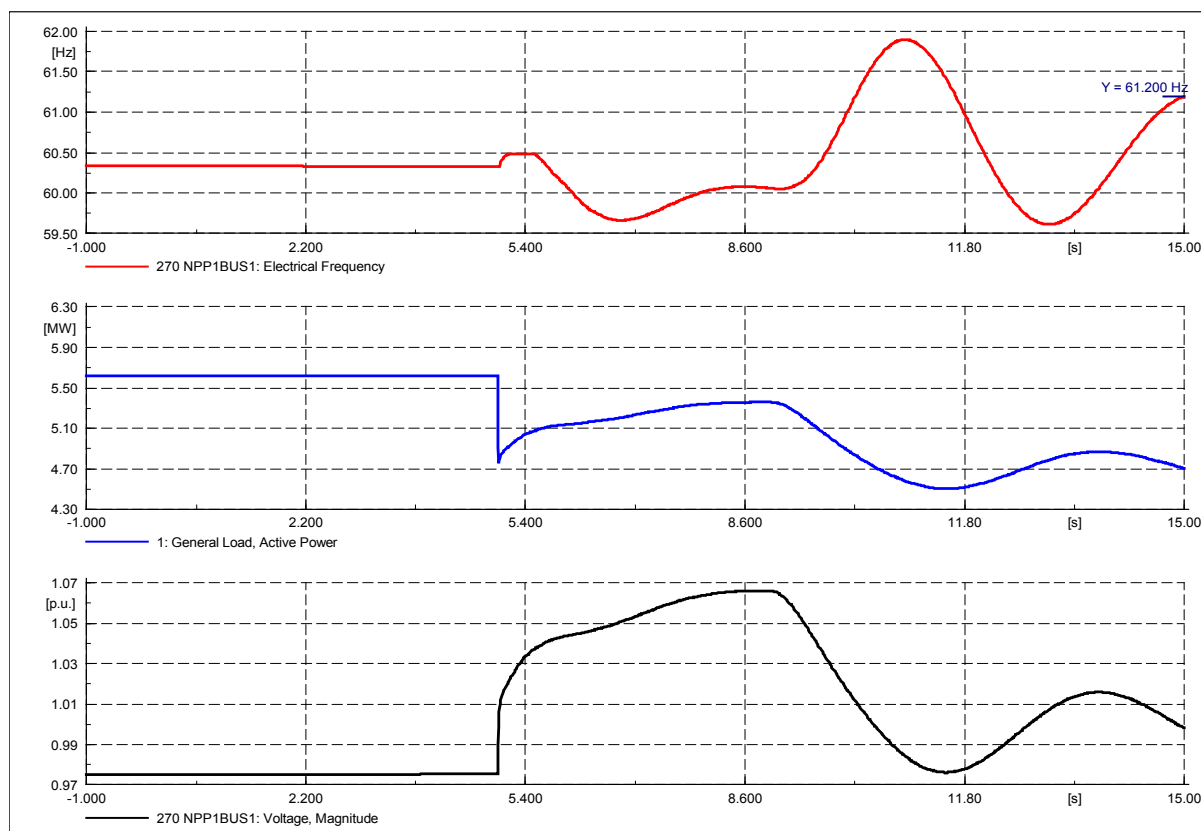
Diesel generator unit 3516C\_G1 (operated at 1,485 kW) is tripped in these studies as the largest generator on the system. The frequency and voltage response of the system are shown in Figure 2-28.

**Figure 2-28: Voltage & frequency response to loss of largest generator**

Upon the loss of the largest generator, the system frequency initially drops to 58.1 Hz which is outside the operational limits. The voltage drops to 0.8 pu which is in excess of the  $\pm 10\%$  limit for voltage. Voltage instability could thus be expected following the loss of the largest generator.

### **Western feeder trip**

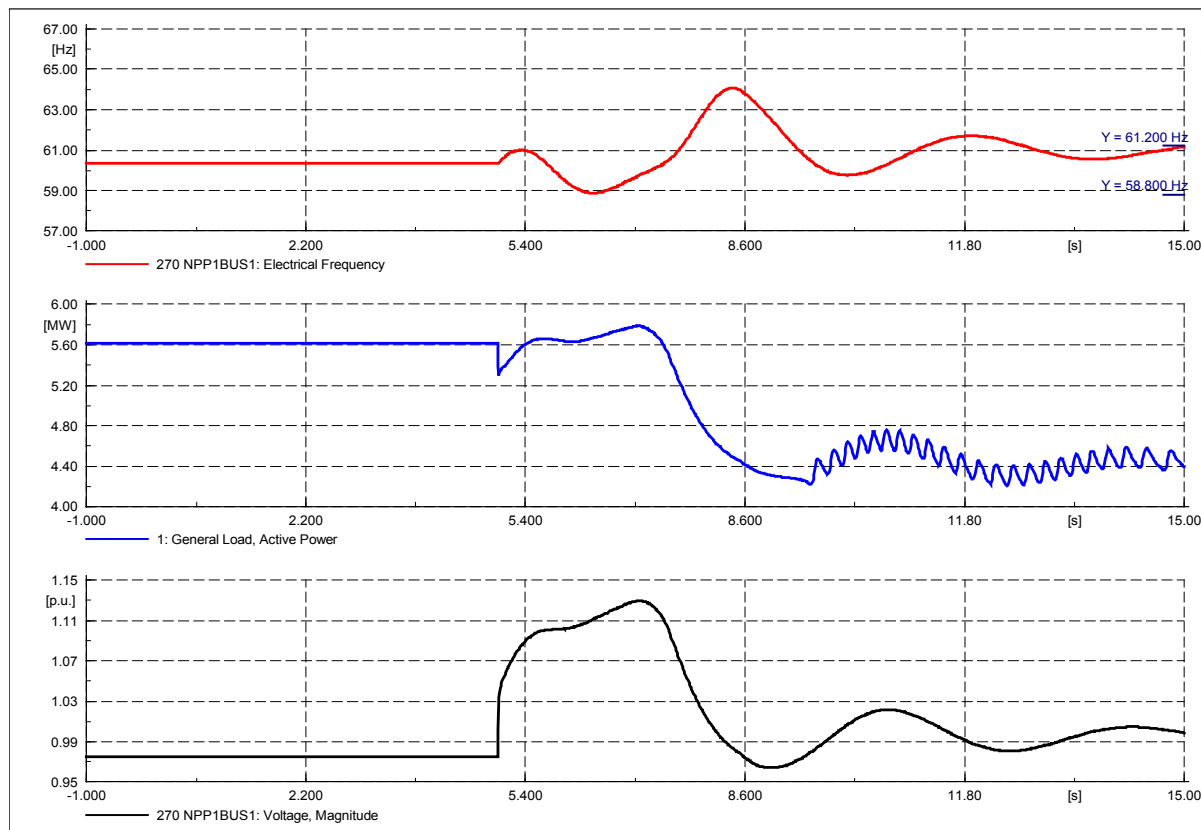
Tripping the Western feeder causes the frequency and voltage responses shown in Figure 2-29.

**Figure 2-29: Voltage & frequency response to loss of Western feeder**

Upon the loss of the Western feeder the frequency swings upwards to almost 62 Hz and continues to oscillate for the duration of the study. The voltage peaks at 1.07 pu and has oscillations which mirror the frequency ones, however the voltage remains within limits for the duration of the study.

### ***Eastern feeder trip***

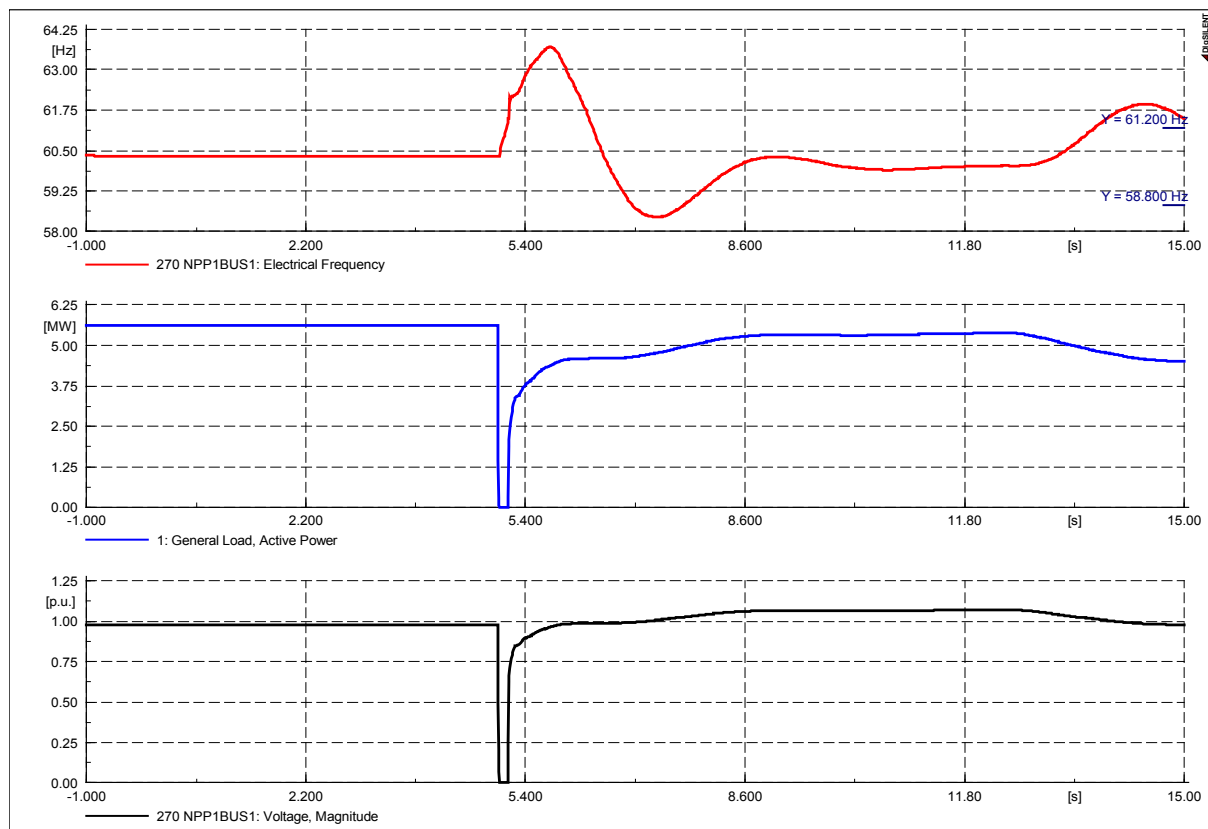
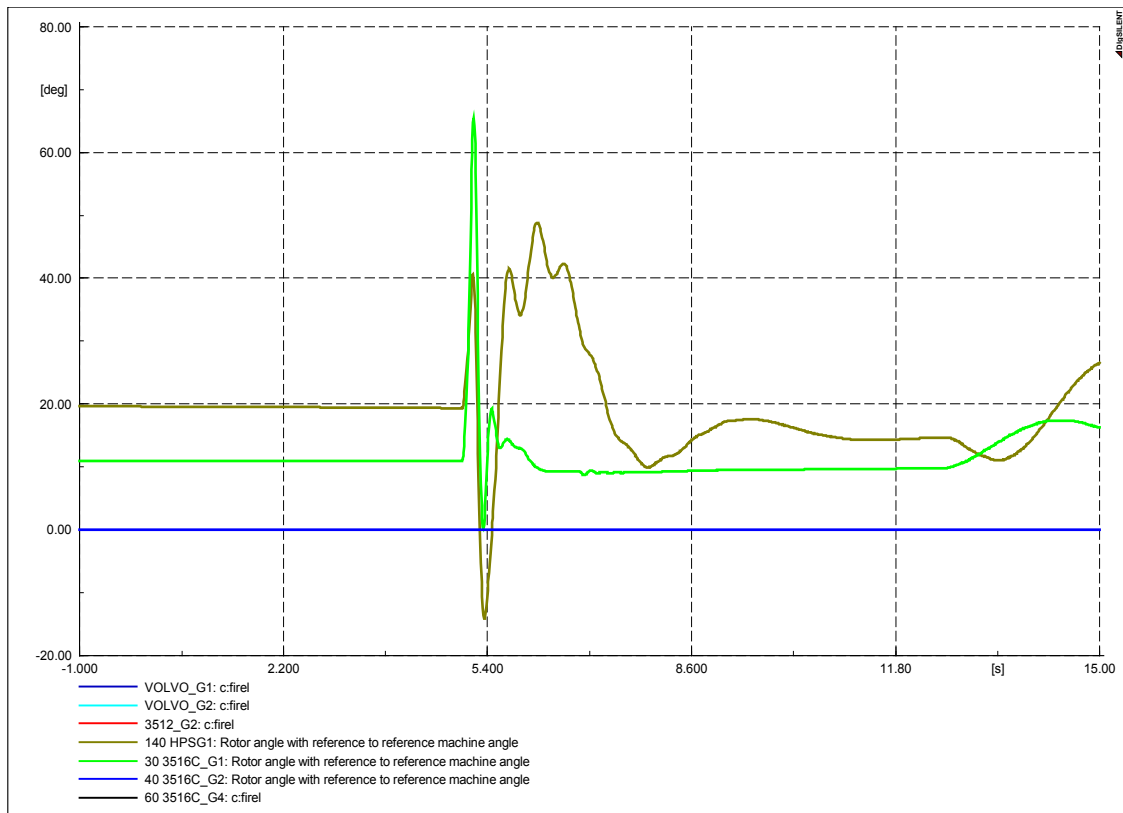
Tripping the Eastern feeder causes the frequency and voltage responses shown in Figure 2-30.

**Figure 2-30: Voltage & frequency response to loss of Eastern feeder**

The loss of the Eastern feeder causes the system frequency to exceed the 2% deviation limit before returning to within the allowable bandwidth and settling. The voltage peaks at 1.13 pu and then reduces to within limits for the duration of the study.

### ***Three phase fault (cleared after 150ms), trip Western feeder***

A three-phase fault was simulated at the power station busbar (NPP1BUS1). The fault was cleared within 150 ms at which point the Western feeder is tripped off. The voltage and rotor angle responses to these events are shown in Figure 2-31 and Figure 2-32 respectively.

**Figure 2-31: Voltage and frequency response to fault and subsequent feeder trip****Figure 2-32: Rotor angle response to fault and subsequent feeder trip**

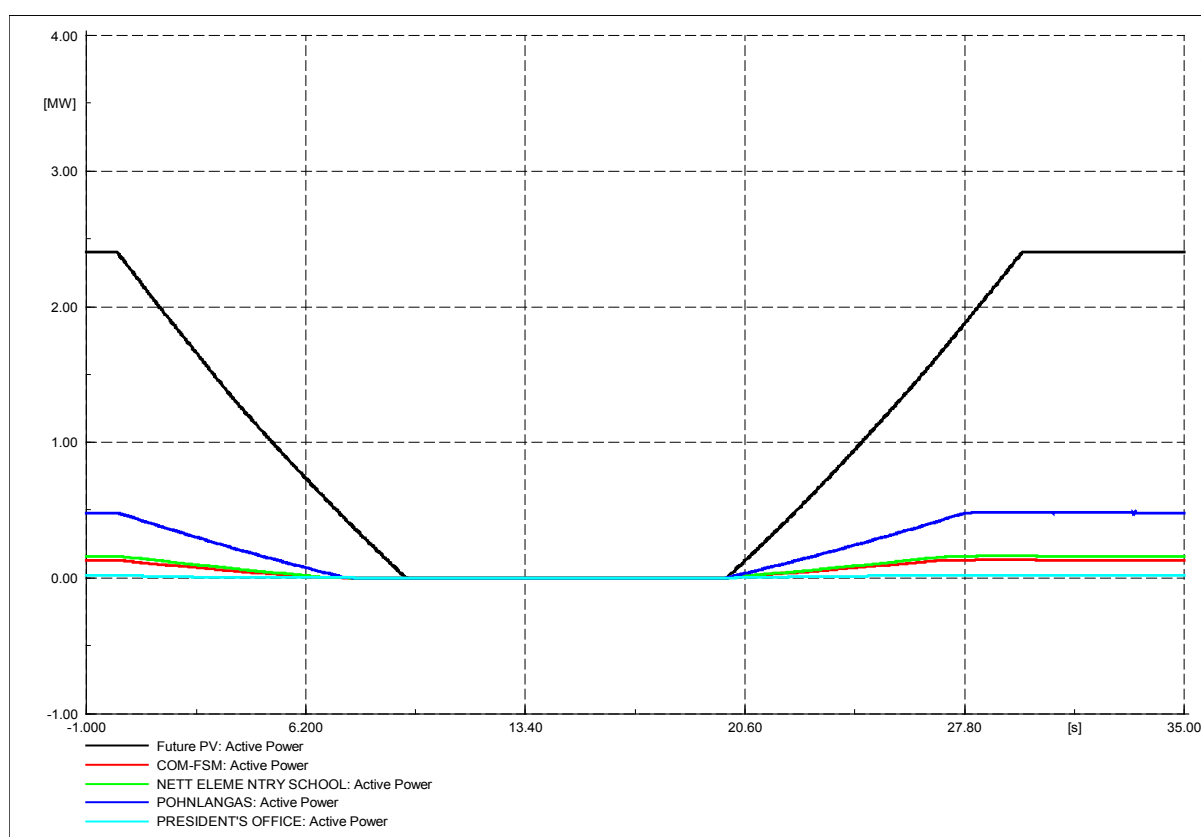


Immediately after the fault, the voltage at the monitored bus (substation busbar) drops to 0 pu. Upon the tripping of the Western feeder, the voltage recovers very quickly (within a few milliseconds) and rises to around 1.05 pu before returning to nominal value again. The operational generators in the system remain in synchronisation without pole-slip subsequent to the fault event however there is a significant rotor swing experienced at the hydro power station and at G1. System frequency oscillates quite significantly outside the  $\pm 2\%$  bandwidth reaching a high of 64 Hz after fault inception.

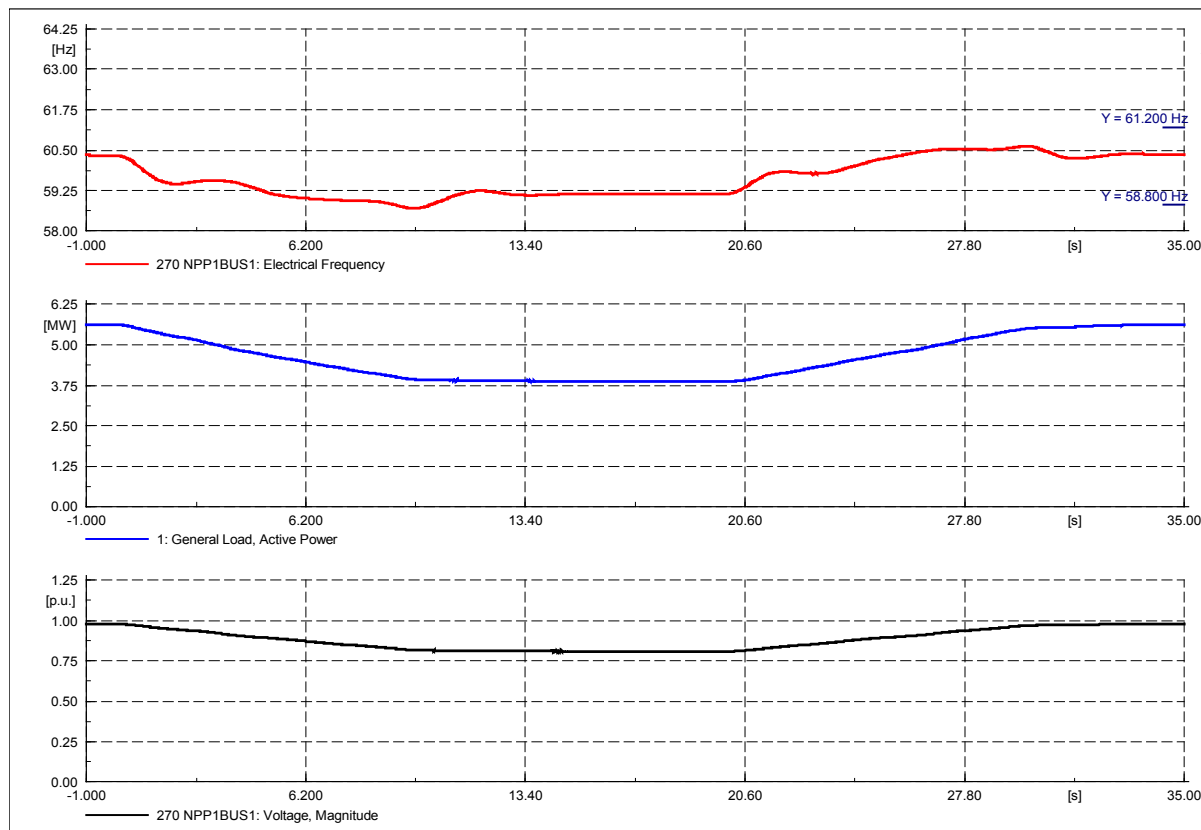
#### **Reduction/increase of PV output to/from maximum/0MW (AVR off)**

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 new PV generation is set to maximum output of 2,400 kW. The PV output is shown in Figure 2-33.

**Figure 2-33: PV MW output of all sites on Pohnpei**



The voltage and frequency responses are shown in Figure 2-34.

**Figure 2-34: Voltage and frequency response to changing PV MW output**

As the MW output of the PV generators decreases, the frequency decreases accordingly to slightly below 58.8 Hz and then steadily returns to nominal. The voltage reduces to 0.8 pu and the system may potentially experience voltage collapse when the PV generators ramp down. The simulation results indicate that in this operational scenario the system is incapable of withstanding the drop and rise of PV generation within the given kW capacity and kW output level.

#### 2.2.4.4 Additional 2400 kW of solar PV generation – Updated generation dispatch

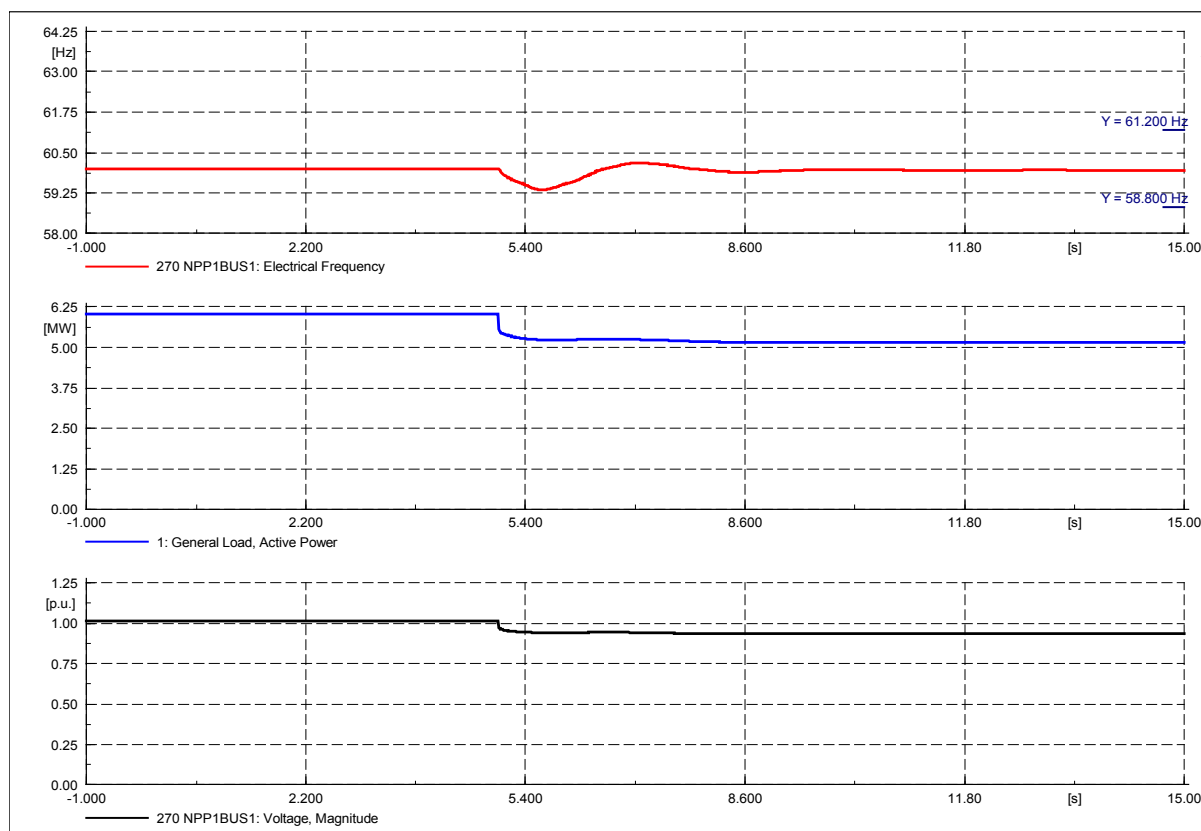
Similar to the response of the system with the existing generation portfolio and with the addition of 1,200kW new PV, there is instability when only two diesels generators and the hydro generator are online and there is a contingency situation. As such, the following sections present the results of studies with 2,400kW of additional PV generation with an updated conventional generation dispatch to provide more spinning reserve. The generation mix assumed for these studies is listed in Table 2-11.

**Table 2-11: Updated generation mix on Pohnpei with additional 2400kW PV generation**

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel & Hydro	HPSG1	2	1	540	185	4.3%
	3516C_G1	3	1	1000	650	15.2%
	3516C_G2	3	1	500	1150	26.8%
	3516C_G4	3	1	500	1150	26.8%
	3516C_G5	3	1	500	1150	26.8%
	3512_G2	3	1	0	0	0.0%
	Peaker_G1	3	1	0	0	0.0%
	Peaker_G2	3	1	0	0	0.0%
	VOLVO_G1	3	1	0	0	0.0%
	VOLVO_G2	3	1	0	0	0.0%
	VOLVO_G3	3	1	0	0	0.0%
	VOLVO_G4	3	1	0	0	0.0%
	<b>Sub-total</b>			<b>3040.0</b>	<b>4285.0</b>	
Renewable	PALIKER (1)	1	1	16.0	0.0	0.0%
	PALIKER (2)	1	1	128.0	0.0	0.0%
	DAUSOKELE1	1	1	160.0	0.0	0.0%
	POHLOK	1	1	480.0	0.0	0.0%
	Future	1	1	2400.0	0.0	0.0%
	<b>Sub-total</b>			<b>3184.0</b>	<b>0.0</b>	
				<b>6224</b>	<b>4285</b>	<b>68.9%</b>

**Loss of largest generator**

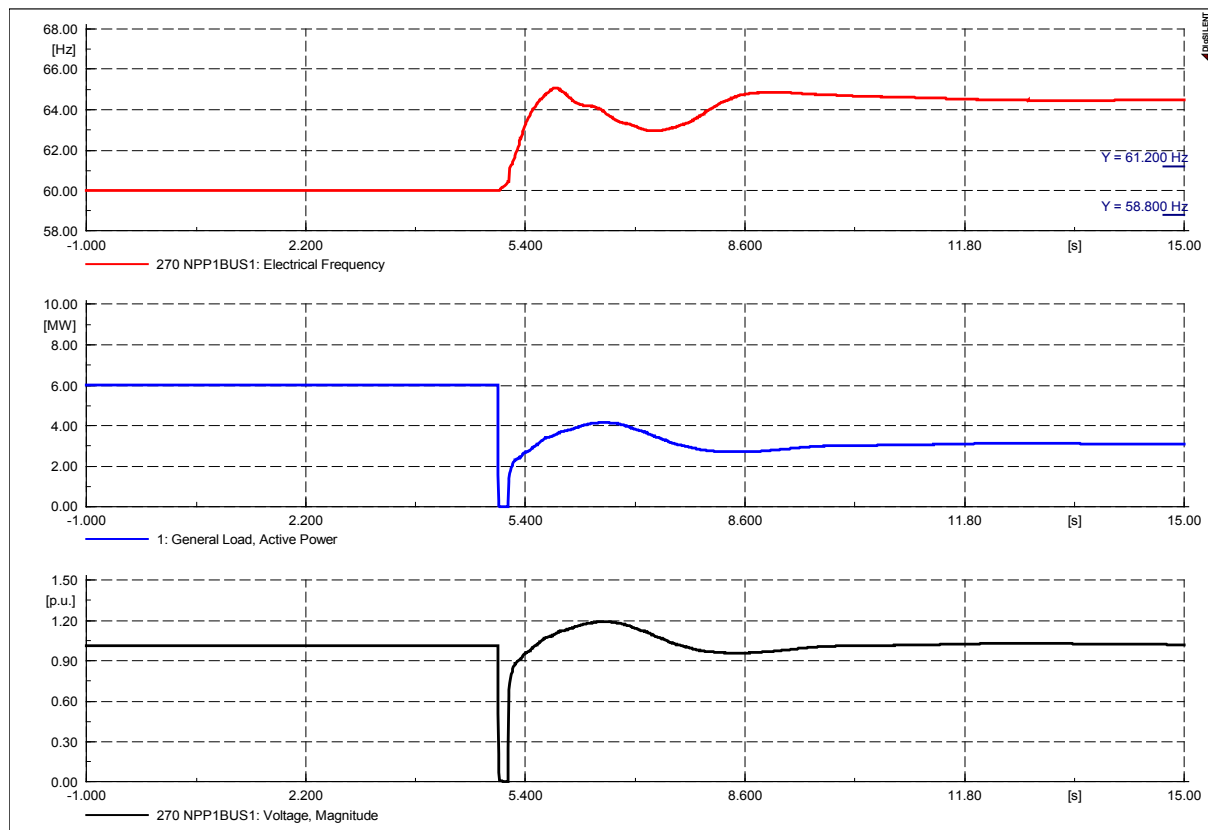
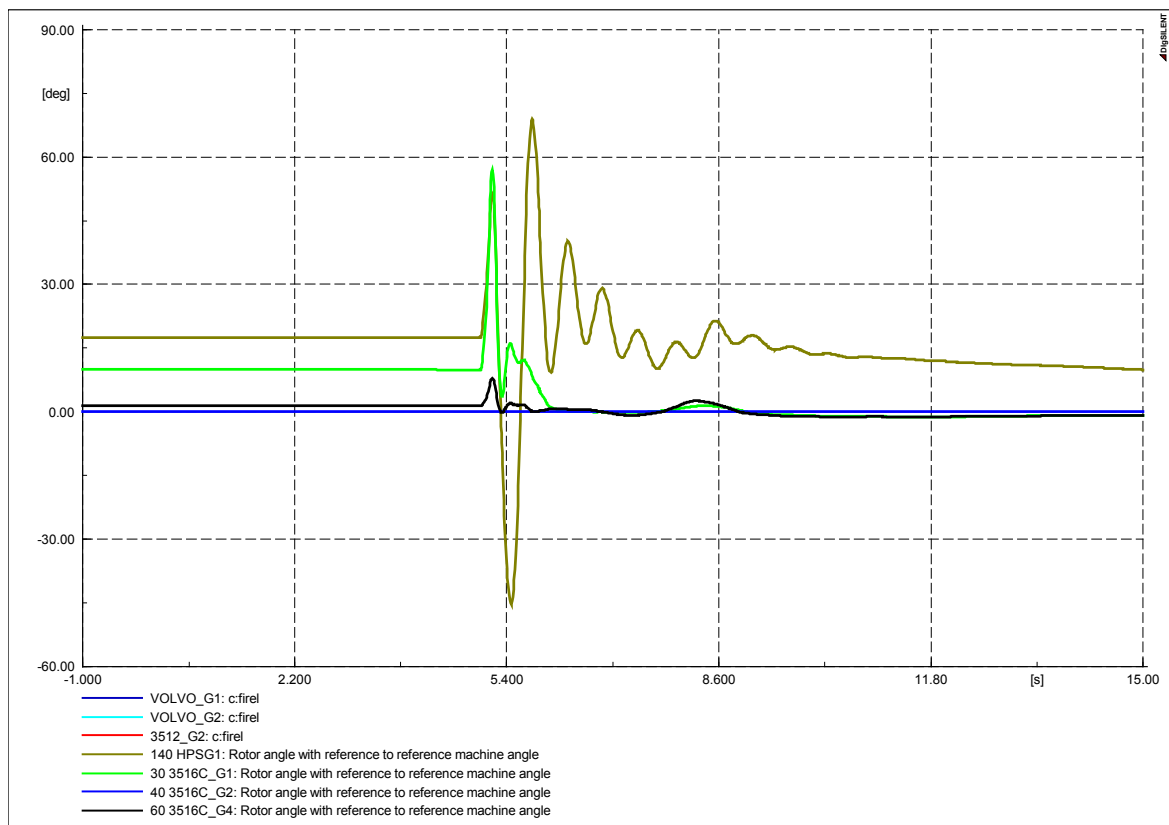
Diesel generator unit 3516C\_G1 (operated at 1,000 kW) is tripped in these studies as the largest generator on the system. The frequency and voltage response of the system are shown in Figure 2-34.

**Figure 2-35: Voltage & frequency response to loss of largest generator**

Upon the loss of the largest generator, the system frequency dips slightly but remains within limits and recovers quickly to nominal. The voltage drops to around 0.95 pu which is well within the  $\pm 10\%$  limit for voltage.

### ***Three phase fault (cleared after 150ms), trip Western feeder***

A three-phase fault was simulated at the power station busbar (NPP1BUS1). The fault was cleared within 150 ms at which point the Western feeder is tripped off. The voltage and rotor angle responses to these events are shown in Figure 2-36 and Figure 2-37 respectively.

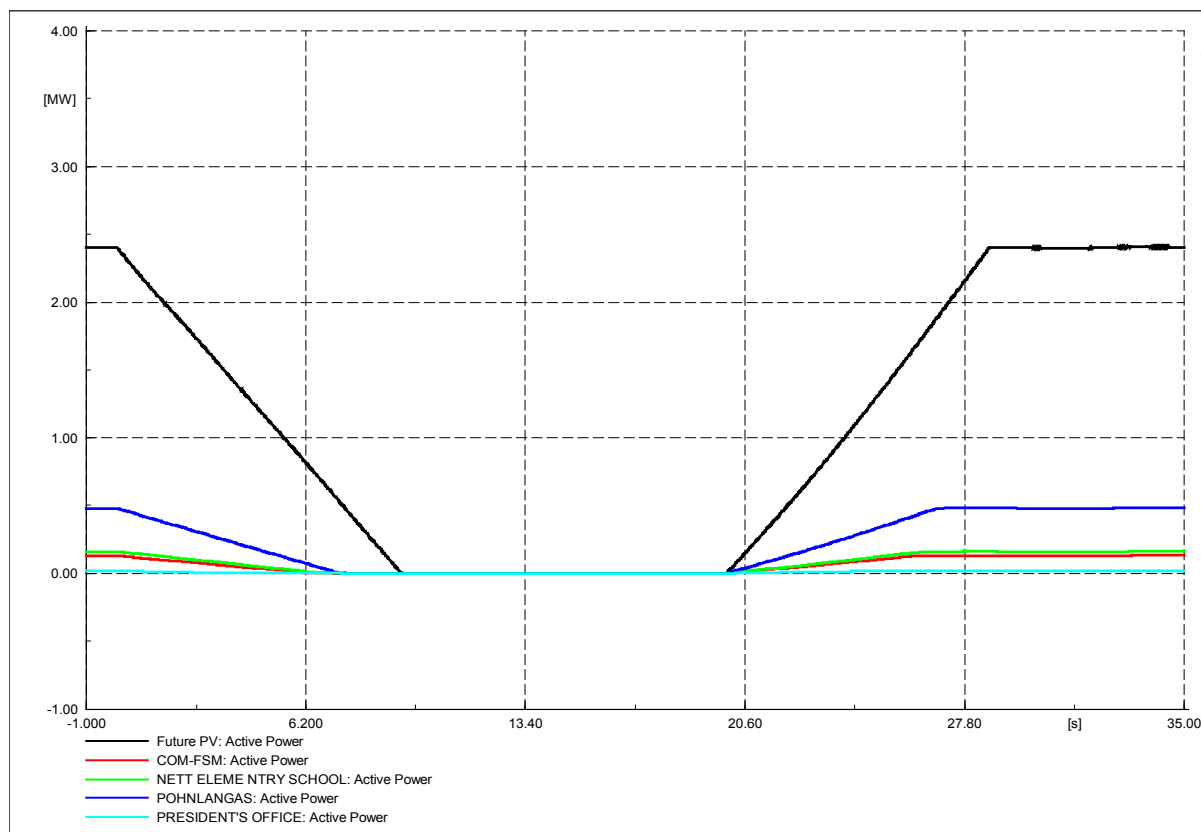
**Figure 2-36: Voltage and frequency response to fault and subsequent feeder trip****Figure 2-37: Rotor angle response to fault and subsequent feeder trip**

Immediately after the fault, the voltage at the monitored bus (substation busbar) drops to 0 pu. Upon the tripping of the Western feeder, the voltage recovers very quickly (within a few milliseconds) and rises to around 1.2 pu before returning to nominal value again. The operational generators in the system remain in synchronisation without pole-slip subsequent to the fault event however there is a significant rotor swing experienced at the hydro power station and at G1. System frequency rises quite significantly outside the  $\pm 2\%$  bandwidth reaching a high of 65 Hz after fault inception and remaining at this high level for the duration of the study.

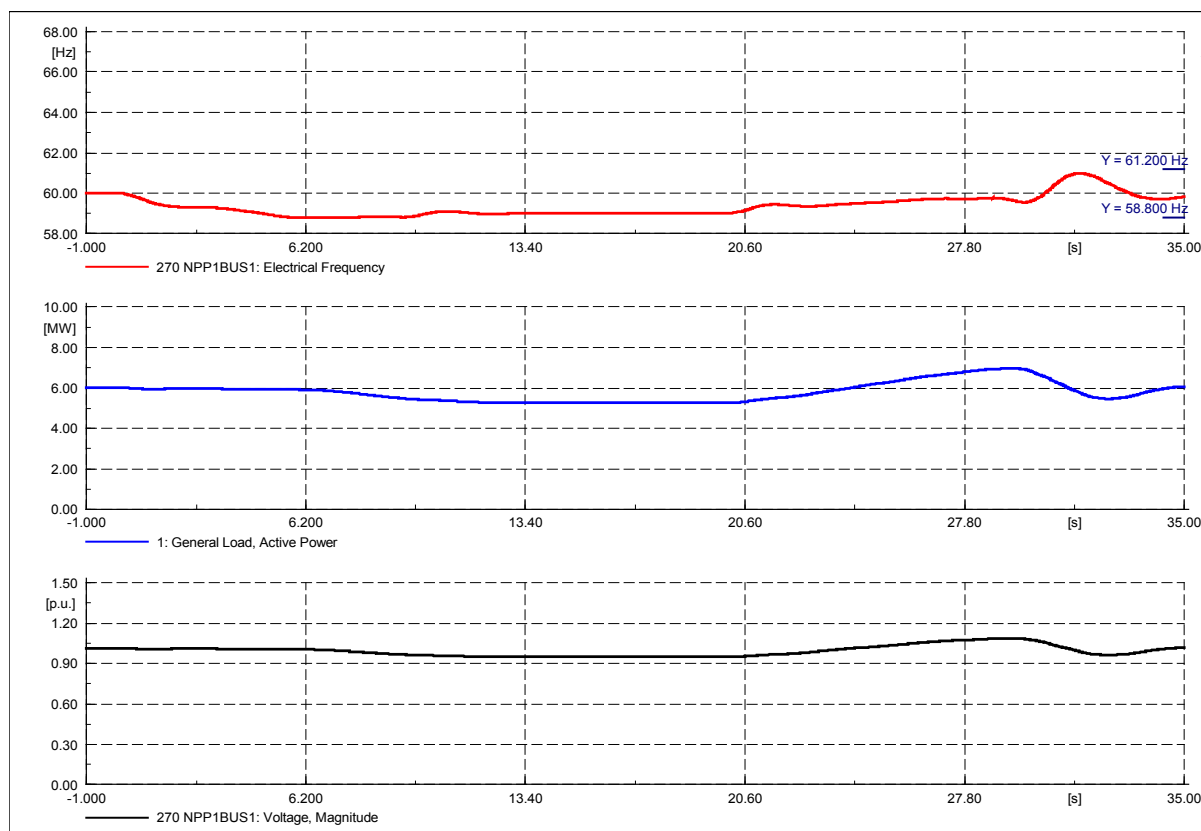
#### **Reduction/increase of PV output to/from maximum/0MW (AVR off)**

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 new PV generation is set to maximum output of 2,400 kW. The PV output is shown in Figure 2-38.

**Figure 2-38: PV MW output of all sites on Pohnpei**



The voltage and frequency responses are shown in Figure 2-39.

**Figure 2-39: Voltage and frequency response to changing PV MW output**

As the MW output of the PV generators decreases, the frequency decreases accordingly to sit on the limit of 58.8 Hz for the duration that the PV output is reduced to 0 kW. The voltage reduces to around 0.94 pu when the PV generators ramp down and rises to 1.1 pu when they ramp up again before reducing back down to around nominal. The simulation results indicate that in this operational scenario the system is capable of withstanding the drop and rise of PV generation within the given kW capacity and kW output level.

### 2.2.5 Summary of power system study results

The results presented in the previous sections show that under normal steady state 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. The system was assessed with and without the existing penetration of PV generation to understand if this impacts system stability. From the simulation results it is evident there is insignificant impact with PV generation added however there are still various instances where the system performance exceeds the allowable limits of frequency and voltage. Changes to the generation dispatch were also assessed to see the benefit of having more conventional generation online, and the provision of spinning reserve. The changes to the generation dispatch profile of the conventional generators improved the response of the system however, there do remain some issues. These are summarised in Table 2-12. The addition of 1,200kW and 2,400kW of PV generation to the system were also studied with different conventional generation dispatch profiles.

**Table 2-12: Summary of Stability Studies with increasing penetrations of VRE**

Study	Loss of largest generator	Loss of Western feeder	Loss of Eastern feeder	Fault at power station then trip of Western feeder	Increase/decrease of PV
Existing system, no PV	Low frequency	High frequency (marginal)	High frequency (marginal) & small oscillations in P	Large frequency oscillations (high & low), high voltage (1.2pu), large rotor angle swings (70deg)	-
Existing system, with PV	Low frequency, low retained voltage	OK	High frequency (marginal) & small oscillations in P	Large frequency oscillations (high & low), high voltage (1.2pu), large rotor angle swings (75 deg)	OK
Existing system, with PV, varied dispatch	Frequency OK, 0.92pu retained voltage	-	-	-	-
1200kW additional PV	Frequency OK, 0.92pu retained voltage	Marginal deviation in frequency	High frequency & small oscillations in P	Large frequency oscillations (high & low), high voltage (1.1pu), large rotor angle swings (80 deg)	Low frequency, low retained voltage (0.75pu) (potential voltage collapse)
1200kW additional PV, varied dispatch	OK	-	-	Frequency out of limits (high & low)	Low retained voltage (0.9pu)
2400kW additional PV	Low frequency (marginal), 0.8pu retained voltage	High frequency	High frequency, high voltage 1.13pu	Frequency out of limits (high & low), large rotor angle swings (60 deg)	Marginal deviation in frequency, low retained voltage (0.8pu) (potential voltage collapse)
2400kW additional PV, varied dispatch	OK	-	-	High frequency, high voltage (1.2pu), large rotor angle swings (70 deg)	Marginal deviation in frequency



There are a variety of issues that need to be addressed to ensure the Pohnpei system can maintain stability in the event of a credible outage. The variation of the generation dispatch definitely improves the response of the system by providing more spinning reserve and fall back generation however more steps should be taken.

### 2.2.6 Recommendations for the present and future scenarios

The Pohnpei network has a reasonable penetration of renewable generation, 1,705 kW, currently connected to the system (about 16.5% of the available generation capacity). There are plans to connect more solar PV to the network in the coming years however it is not known exactly where and how much this will be.

The results of the stability studies indicate there must be improvements made to the network to ensure it is more robust. The voltage in many cases reaches  $\pm 20\%$  of nominal and so increased voltage support is recommended to prevent such large fluctuations. The frequency response exceeds the 2% acceptable limit in many cases, however, in many other cases the violation is marginal and so the introduction of battery storage to the island could help to improve the frequency response and keep it within the limits.

Support at the hydro power station to maintain stability is recommended as it is particularly affected by large rotor angle swings upon the loss of the feeders since it is connected to the Eastern feeder and so is particularly impacted by this change in power system configuration.

## 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.

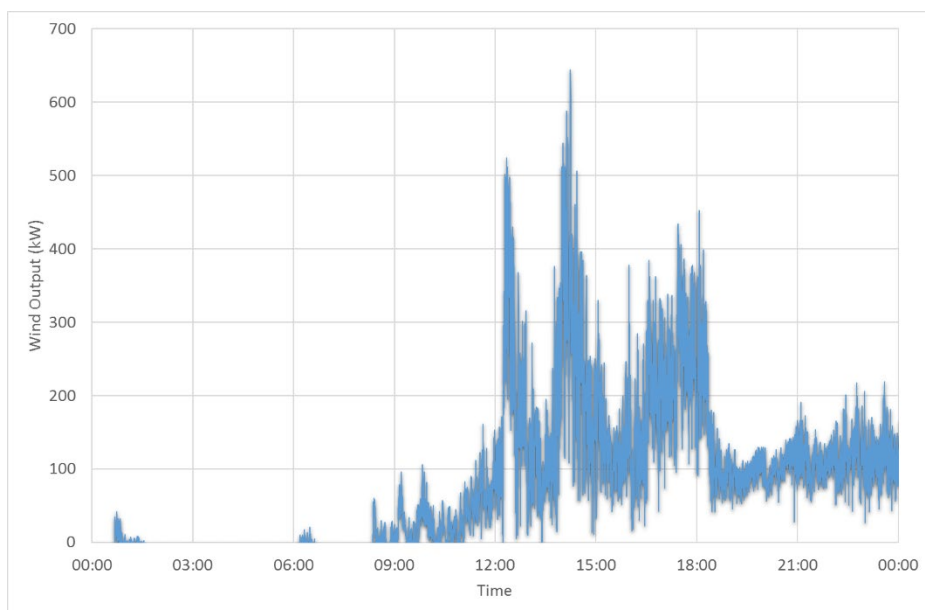
The balancing of supply and demand has become one of the critical limiting factors in the increase of wind and solar generators for grids. Dynamic stability aspects of the network, such as voltage and frequency control, require fast response from generators, storage facilities and/or demand-response 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 Pohnpei and the technical limit with the economic impact for increasing solar power.

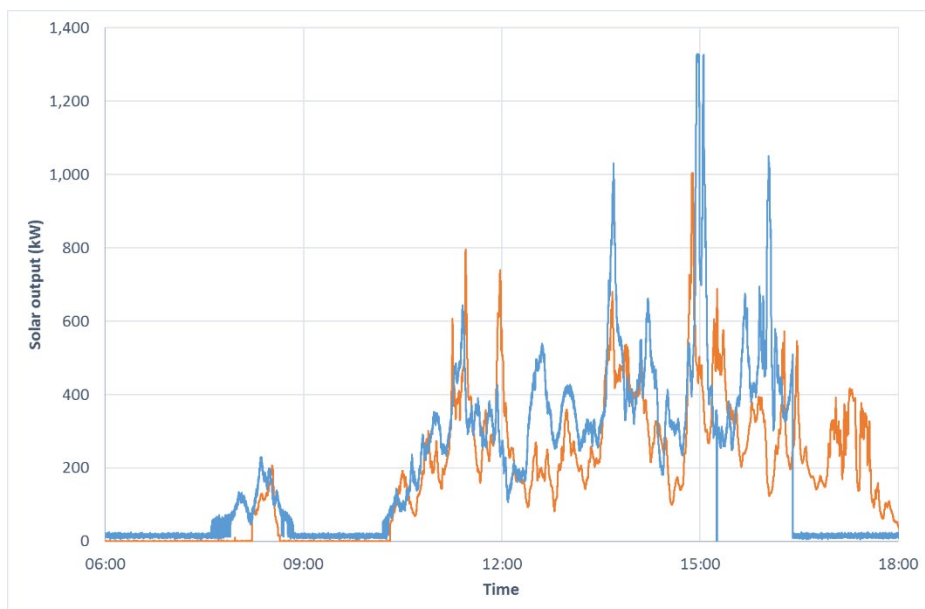
#### 3.1.1 Wind and Solar intermittency

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 which, has been used as an example.

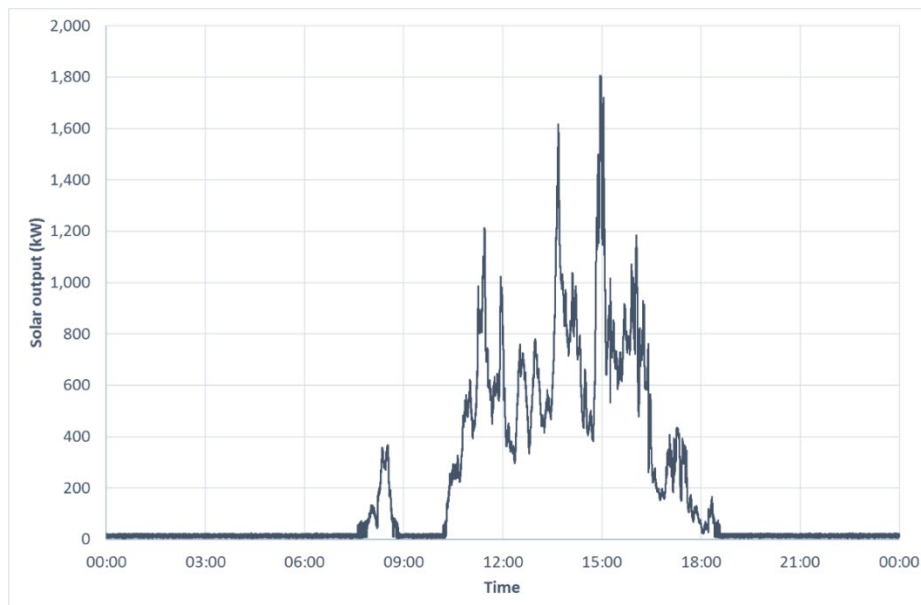
**Figure 3-1. Wind power for recorded on 10 December 2016 at Aleipata**

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 grid 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.

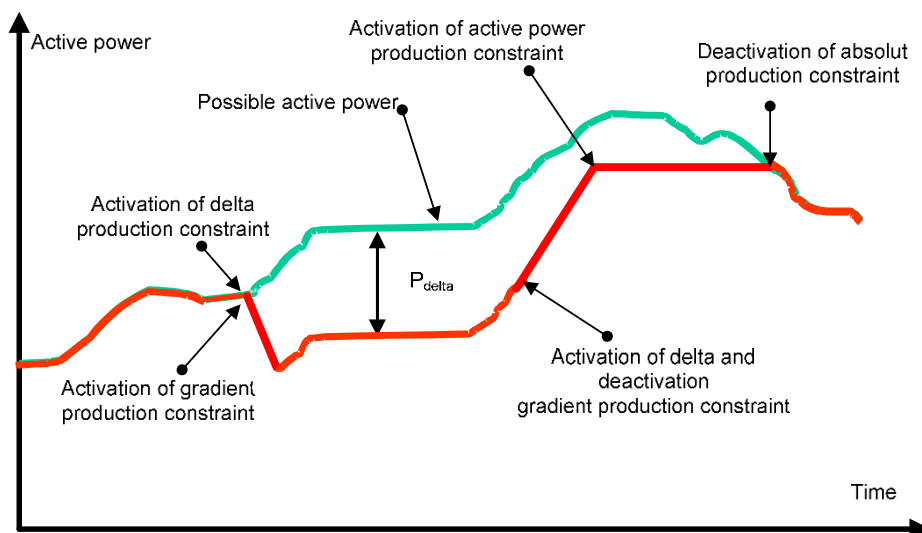
### 3.1.2 VRE enhanced frequency control provision and calculation of costs

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

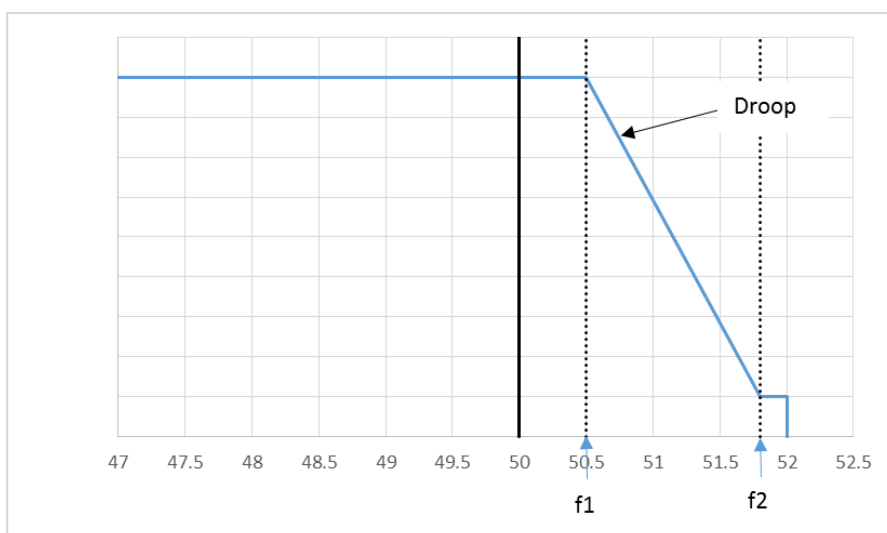
curtailed but there is no reduction in capital cost. Thus, if before implementing the scheme, the plant was generating at an average cost of \$0.10 / kWh, after introduction of the scheme, the plant's average cost will be increased to \$0.11 / kWh as the scheme reduces the generator output by 10%.

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



**Option 2: VRE provides high-frequency response only** – 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.

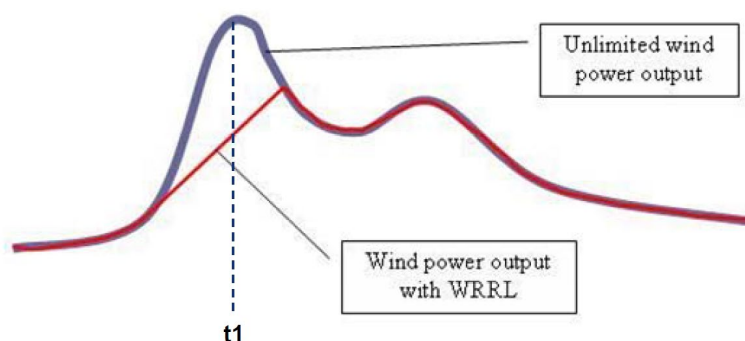
**Figure 3-5 Typical VRE high frequency response only**



**Option 3: VRE ramp rate is limited** – 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)<sup>1</sup>**



### 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<sup>2</sup>. 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<sup>3</sup>.

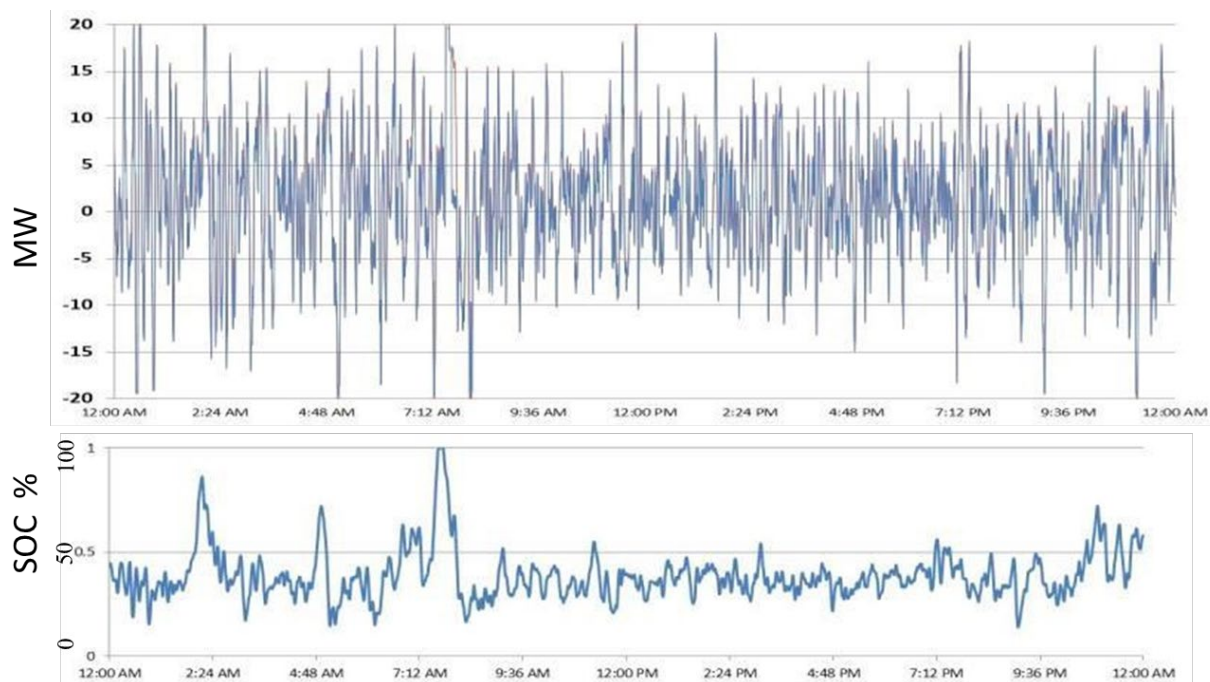
<sup>1</sup> AESO System Impact Studies, Phase 2 Assessing the impacts of increased wind power on AIES operations and mitigating measures, July 2006

<sup>2</sup>

[http://www.sandia.gov/ess/docs/pr\\_conferences/2014/Thursday/Session7/02\\_Areseneaux\\_Jim\\_20MW\\_Flywheel\\_Energy\\_Storage\\_Plant\\_140918.pdf](http://www.sandia.gov/ess/docs/pr_conferences/2014/Thursday/Session7/02_Areseneaux_Jim_20MW_Flywheel_Energy_Storage_Plant_140918.pdf)

<sup>3</sup> 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<sup>4</sup>. 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
- 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.

<sup>4</sup> 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

### 3.1.5 Batteries and calculation of costs

The most feasible current battery technologies are Sodium Sulphur (NaS) and Lithium-ion (Li-ion)<sup>5</sup>. 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<sup>6</sup> and for NaS US\$2,200 / kWh<sup>7</sup>. The cost of inverter is estimated to be US\$1,000 / kW<sup>8</sup>.

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

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 cost break down is \$375 /kWh for batteries and US\$ 500 / kW for inverters.

The estimated capital cost for batteries for Pohnpei of 2 MW with 2 MWh is \$ 1.0 m for inverters and \$0.75 m for batteries a total of \$1,750,000. 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<sup>11</sup>, the annualised cost is \$209,821 as shown by annuity calculator below:

#### Annuity Payout Calculator

Installed Capacity	2000	kW
	2	MW
Capital Expenditure	\$ 1,750,000	USD
	1.75	m USD
Fixed Opex	\$ 15,000	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	\$ 194,821	USD
Fixed Opex	\$ 15,000	USD
Variable Opex	\$ -	USD
Total	\$ 209,821	USD

Inputs in yellow

<sup>5</sup> 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

<sup>6</sup> Energy Master Plans for the Federated States of Micronesia, Castalia, 2018

<sup>7</sup> 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

<sup>8</sup> Energy Master Plans for the Federated States of Micronesia, Castalia, 2018

<sup>9</sup> <https://www.bloomberg.com/news/articles/2018-03-08/the-battery-will-kill-fossil-fuels-it-s-only-a-matter-of-time>

<sup>10</sup> US TRADE AND DEVELOPMENT AGENCY, South Africa Energy Storage, Technology and Market Assessment, March 2017

<sup>11</sup> US TRADE AND DEVELOPMENT AGENCY, South Africa Energy Storage, Technology and Market Assessment, March 2017



## 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®.

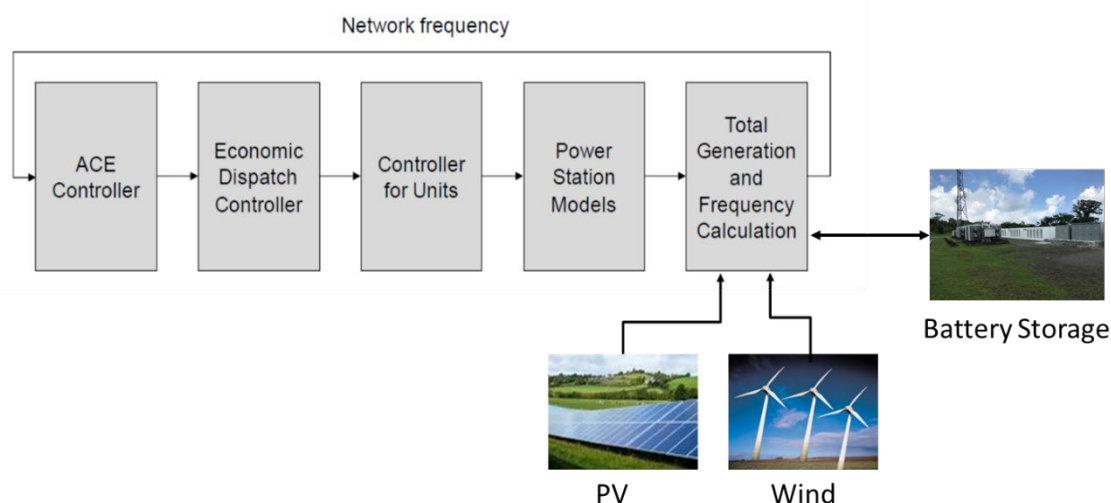
The Generation Dispatch Analysis Tool is used for four main purposes

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 Pohnpei 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 undertaken 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 Pohnpei, 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.

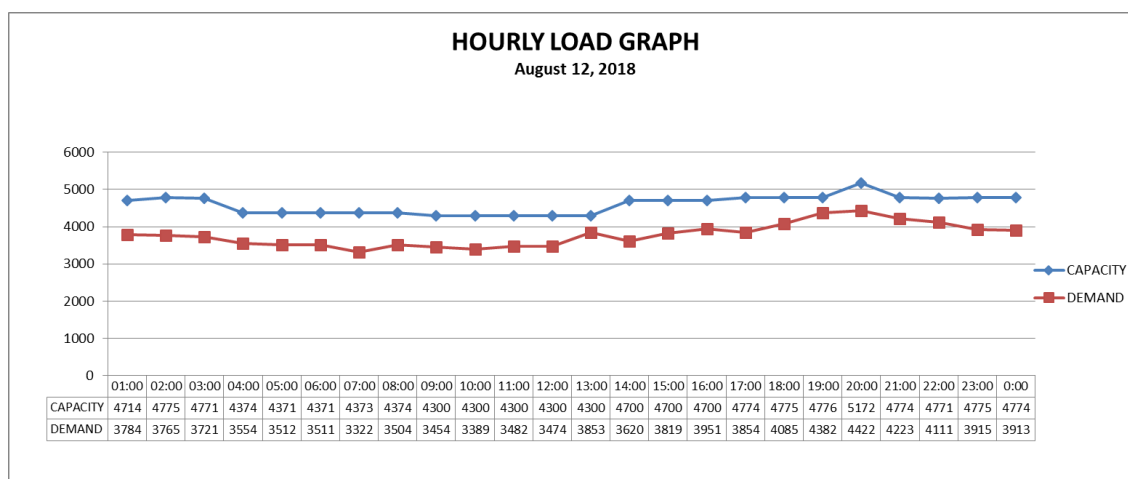
### 3.2.2 Input data to GDAT for Pohnpei studies

The models developed for Pohnpei are based on hourly data records received for the week of 06 August 2018. The real time PV data was obtained from recorded 2 second data from the reservoir at Majuro where we have records for the 0.6 MW PV plant. This is the same plant size as for Pohnlangas PV plant. For the Solar PV that is installed in town we have taken the PV records from Majuro reservoir for another 'similar' day and scaled this to 0.4 MW to account for school PV and other sites.

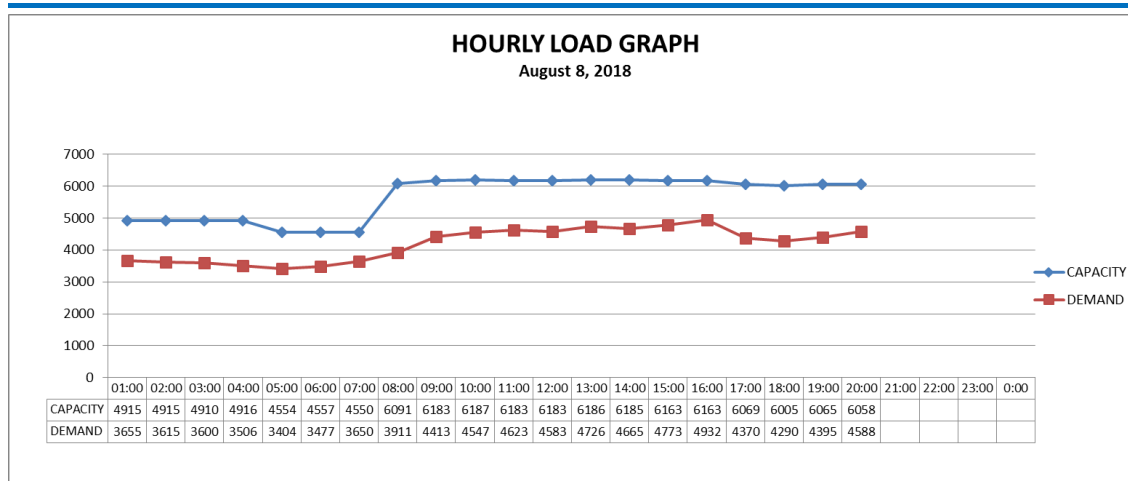
The weekend demand profile is taken from data provided by Pohnpei as recorded on Sunday the 12 August 2018, shown in Figure 3-9.

The weekday demand profile is taken from data provided by Pohnpei as recorded on Wednesday 08 August 2018, as shown in Figure 3-10.

**Figure 3-9 Pohnpei demand profile for weekend recorded on 12 August 2018**



**Figure 3-10 Pohnpei demand profile for weekday recorded on 08 August 2018**



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
NPP1 U2	1650	Cat Diesel	D1
NPP1 U3	1650	Cat Diesel	D2
NPP1 U4	1650	Cat Diesel	D3
NPP4 U1	400	Cat Diesel	D4
NPP4 U 2	400	Cat Diesel	D5
NPP 5 U1	350	Volvo	D6
NPP 5 U2	350	Volvo	D7
NPP 5 U3	350	Volvo	D8
NPP 5 U4	350	Volvo	D9
Nanpil Hydro	500	Hydro	H1
School and COM-FSM	400	PV	PV1
Pohnlangas	600	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 and PV power plants are shown in Table 3-2 and Table 3-3.

. Table 3-2: Pohnpei diesel generation parameters

Power Generation Dispatch - C:\PPA\saexample\Projects\Pohnpei\Pohnpei_12MWPV_8MW_8MWh_Batt_AGC.mat										
File View Simulation										
Data Station										
Diesel	PV	Wind	Batt	Hydro						
	D1	D2	D3	D4	D5	D6	D7	D8	D9	
MCR	1.6500	1.6500	1.6500	0.4000	0.4000	0.3500	0.3500	0.3500	0.3500	
Unit Inertia	0.4500	0.4500	0.4500	0.4500	0.4500	0.4500	0.4500	0.4500	0.4500	
Ramp Rate	1.6500	1.6500	1.6500	0.4000	0.4000	0.3500	0.3500	0.3500	0.3500	
Maximum Generation	1.6500	1.6500	1.6500	0.4000	0.4000	0.3500	0.3500	0.3500	0.3500	
Minimum Generation	0.1650	0.1650	0.1650	0.0800	0.0800	0.0700	0.0700	0.0700	0.0700	
Spinning Capability	1.6500	1.6500	1.6500	1.6500	0.6000	0.3500	0.3500	0.3500	0.3500	
Nonspinning Capability	1.6500	1.6500	1.6500	1.6500	0.6000	0.3500	0.3500	0.3500	0.3500	
AGC On	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
Model Name	DEGOV1	DEGOV1	DEGOV1	DEGOV1	DEGOV1	DEGOV1	DEGOV1	DEGOV1	DEGOV1	
Frequency Deadband	1.0000e-03	1.0000e-03	1.0000e-03	1.0000e-03	1.0000e-03	1.0000e-03	1.0000e-03	1.0000e-03	1.0000e-03	
Lower Frequency Limit	-1	-1	-1	-1	-1	-1	-1	-1	-1	
Upper Frequency Limit	1	1	1	1	1	1	1	1	1	
Droop	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800	
	D1	D2	D3	D4	D5	D6	D7	D8	D9	
Droop Control	0	0	0	0	0	0	0	0	0	
T1	15	15	15	15	15	15	15	15	15	
T2	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000	
T3	5	5	5	5	5	5	5	5	5	
T4	5	5	5	5	5	5	5	5	5	
T5	5	5	5	5	5	5	5	5	5	
T6	0.2500	0.2500	0.2500	0.2500	0.2500	0.2500	0.2500	0.2500	0.2500	
	D1	D2	D3	D4	D5	D6	D7	D8	D9	
Megawatts	[0 0.456 0.91 ...]	[0 0.456 0.91 ...]	[0 0.456 0.91 ...]	[0 0.1 0.2 0.3 ...]	[0 0.1 0.2 0.3 ...]	[0 0.09 0.18 0 ...]	[0 0.09 0.18 0 ...]	[0 0.09 0.18 0 ...]	[0 0.09 0.18 0 ...]	
Cost	[456 258 235 ...]	[456 258 235 ...]	[456 258 235 ...]	[456 258 235 ...]	[456 258 235 ...]	[415 240 200 ...]	[415 240 200 ...]	[415 240 200 ...]	[415 240 200 ...]	

Table 3-3: Pohnpei PV parameters

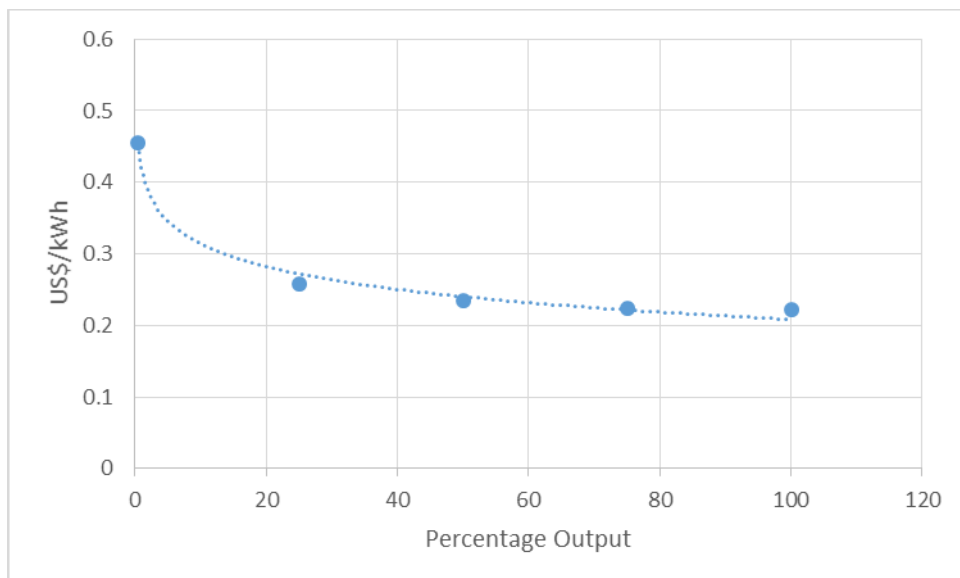
Power Generation Dispatch - C:\PPA\saexample\Projects\Pohnpei\Pohnpei\_base\_4.mat

File View Simulation

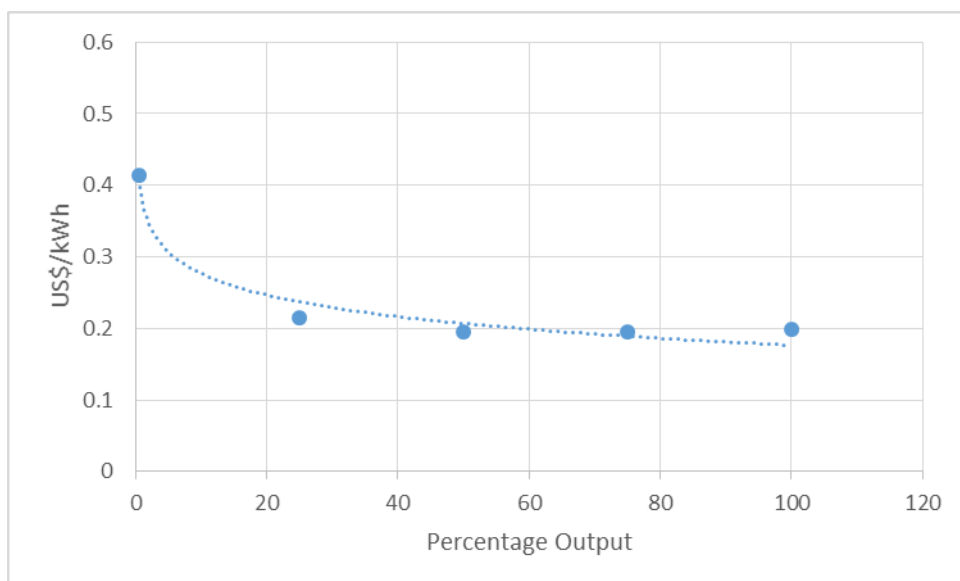
Diesel	PV	Wind	Batt	Hydro
		</		

The fuel cost curve that plots power against US\$/kWh for CAT units, as shown in Figure 3-11 below, is based on CAT manufacturers diesel generator's performance<sup>12</sup>. The cost curve was drawn for a fuel cost of US\$ 0.829 per litre<sup>13</sup>. The minimum generation is set to be at 20% of the rated capacity as a typical minimum value. Similar calculations were performed for Volvo units<sup>14</sup>, as shown in Figure 3-12.

**Figure 3-11 CAT diesel units cost curve**



**Figure 3-12 Volvo diesel units cost curve**



The key parameters for the AGC controller are shown in Figure 3-13 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 Pohnpei the simulation is run every second for a day.

<sup>12</sup> Caterpillar manual CAT XQ2000

<sup>13</sup> Email correspondence with Pohnpei, August 2018

<sup>14</sup> 3.1.1 GESAN DVS630 datasheet.pdf

**Figure 3-13 GDAT controller parameters**

Power Generation Dispatch - C:\PPA\saexample\Projects\Pohnpei\Pohnpei\_12MWPV\_8MW\_8MWh\_Batt\_AGC.mat

File View Simulation

**Data** Station

**System**

Simulation Start Date: 2018-08-08      Simulation End Date: 2018-08-09

Simulation Start Time: 00:00:00      Simulation End Time: 00:00:00

**System**

System frequency (Hz): 60      Frequency data file name: Projects\Pohnpei\Data\treq\_MW.csv

Peak demand (MW): 6      Demand data file name: Projects\Pohnpei\Data\demand.csv

Data file date format: yyyy-MM-dd HH:mm:ss

**Constraint**

Spinning Reserve (MW): 0.6

Nonspinning Reserve (MW): 0

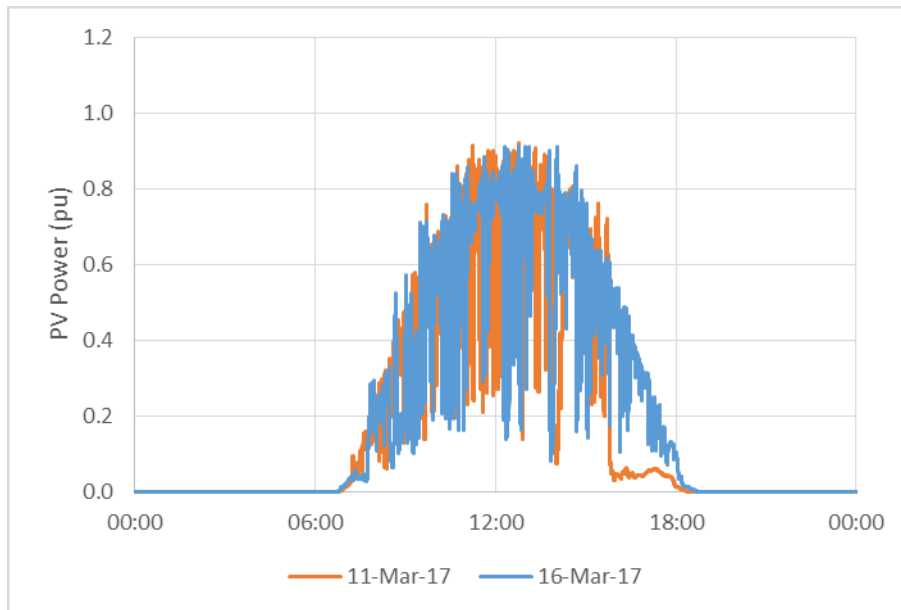
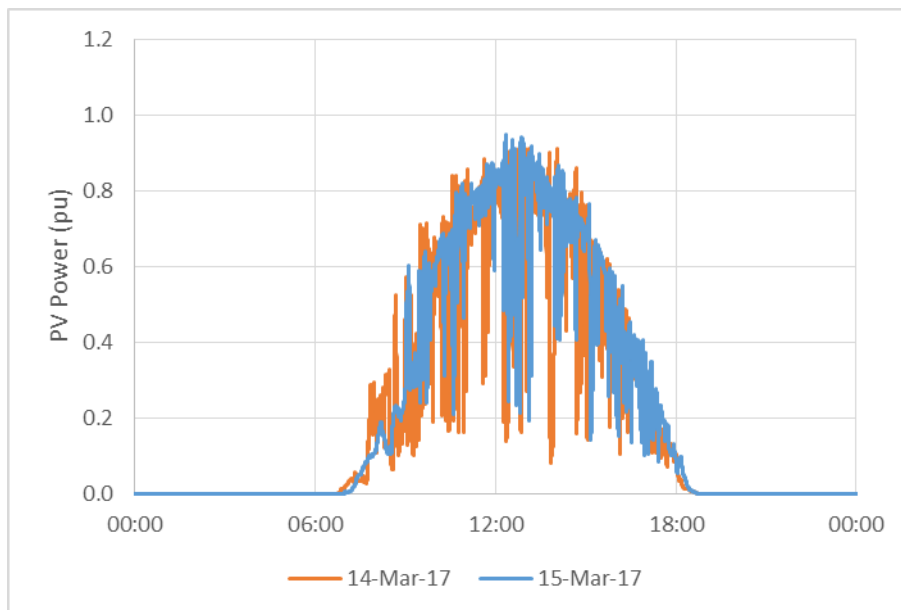
**Controller**

Sample Time: 1      Controller proportional gain: 0.05

Controller deadband: 0.01      Controller integral gain: 0

AGC controller type: 1      Controller derivative gain: 0

The solar PV power output dates chosen were the week of 11 March as provided by MEC which recorded the 1 second output at the reservoir PV plant. Base case 1 and base case 3 PV1 data is from 11 March 2017 and PV2 data from 16 March 2017 as shown in Figure 3-14 which was a typical partially cloudy days in the pacific islands with constant drops in PV power. Base 2 and 4 is PV data from 14 and 15 March 2017, as shown in Figure 3-15, which was a relatively sunny days with significant periods of low PV output followed full output from the PV plants

**Figure 3-14 Recorded 'normalised' one second PV output Base Case 1 and 3****Figure 3-15 Recorded 'normalised' one second PV output Base case 2 and 4**

### 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 3-4.

**Table 3-4 Simulations performed**

Case Number	Simulation date	VRE Installed (MW)	% peak	PV data date	Controller status	
					Solar PV	Battery
<b>Base 1</b>	12 Aug 2018	1	20%	11&16/03/17	AGC	off
<b>1</b>	12 Aug 2018	3	60%	11&16/03/17	AGC	off
<b>2</b>	12 Aug 2018	3	60%	11&16/03/17	AGC	1 MW / 1 MWh on Gov
<b>3</b>	12 Aug 2018	6	120%	11&16/03/17	AGC	2 MW / 2 MWh on Gov
<b>4</b>	12 Aug 2018	9	180%	11&16/03/17	AGC	4 MW / 4 MWh on Gov & AGC
<b>5</b>	12 Aug 2018	12	240%	11&16/03/17	AGC	8 MW / 8 MWh on Gov & AGC
<b>6</b>	12 Aug 2018	12	240%	11&16/03/17	AGC	8 MW / 8 MWh on Gov & AGC – diesel off
<b>Base 2</b>	12 Aug 2018	1	20%	14&15/03/17	AGC	off
<b>7</b>	12 Aug 2018	3	60%	14&15/03/17	AGC	off
<b>8</b>	12 Aug 2018	3	60%	14&15/03/17	AGC	1 MW / 1 MWh on Gov
<b>9</b>	12 Aug 2018	6	120%	14&15/03/17	AGC	2 MW / 2 MWh on Gov
<b>10</b>	12 Aug 2018	9	180%	14&15/03/17	AGC	4 MW / 4 MWh on Gov & AGC
<b>11</b>	12 Aug 2018	12	240%	14&15/03/17	AGC	8 MW / 8 MWh on Gov & AGC
<b>12</b>	12 Aug 2018	12	240%	14&15/03/17	AGC	8 MW / 8 MWh on Gov & AGC – diesel off
<b>Base 3</b>	8 Aug 2018	1	20%	11&16/03/17	AGC	off
<b>13</b>	8 Aug 2018	3	60%	11&16/03/17	AGC	off
<b>14</b>	8 Aug 2018	3	60%	11&16/03/17	AGC	1 MW / 1 MWh on Gov
<b>15</b>	8 Aug 2018	6	120%	11&16/03/17	AGC	2 MW / 2 MWh on Gov
<b>16</b>	8 Aug 2018	9	180%	11&16/03/17	AGC	4 MW / 4 MWh on Gov & AGC
<b>17</b>	8 Aug 2018	12	240%	11&16/03/17	AGC	8 MW / 8 MWh on Gov & AGC
<b>18</b>	8 Aug 2018	12	240%	11&16/03/17	AGC	8 MW / 8 MWh on Gov & AGC – diesel off
<b>Base 4</b>	8 Aug 2018	1	20%	14&15/03/17	AGC	off
<b>19</b>	8 Aug 2018	3	60%	14&15/03/17	AGC	off
<b>20</b>	8 Aug 2018	3	60%	14&15/03/17	AGC	1 MW / 1 MWh on Gov
<b>21</b>	8 Aug 2018	6	120%	14&15/03/17	AGC	2 MW / 2 MWh on Gov
<b>22</b>	8 Aug 2018	9	180%	14&15/03/17	AGC	4 MW / 4 MWh on Gov & AGC
<b>23</b>	8 Aug 2018	12	240%	14&15/03/17	AGC	8 MW / 8 MWh on Gov & AGC



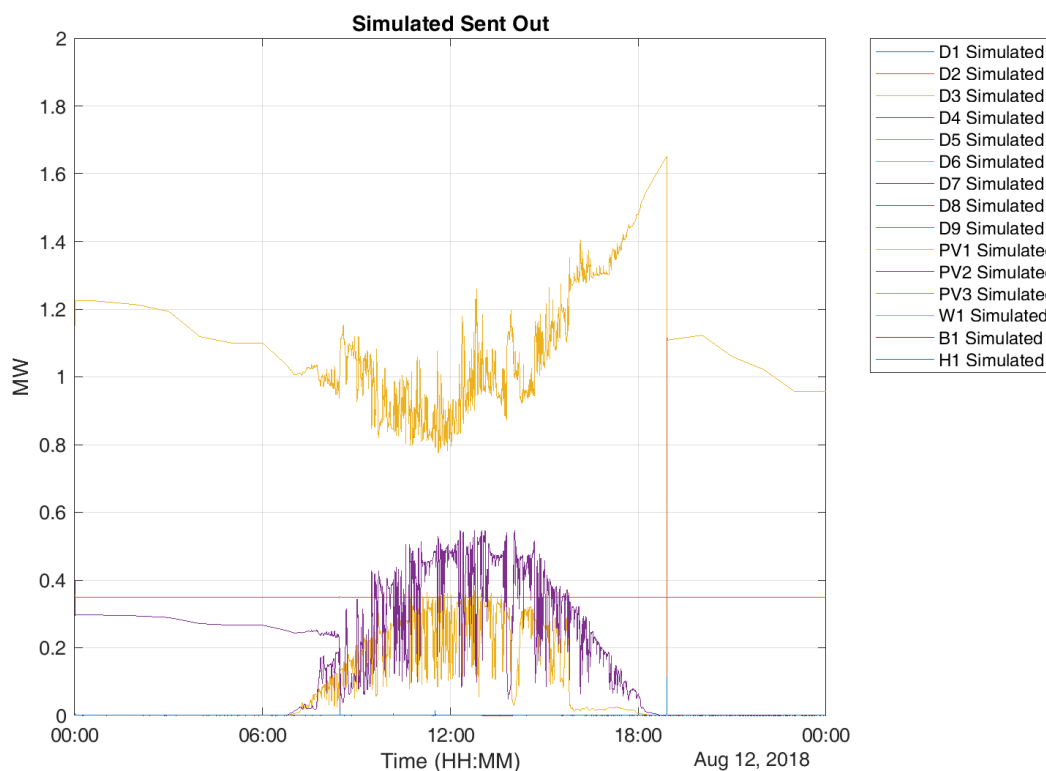
24	8 Aug 2018	12	240%	14&15/03/17	AGC	8 MW / 8 MWh on Gov & AGC – diesel off
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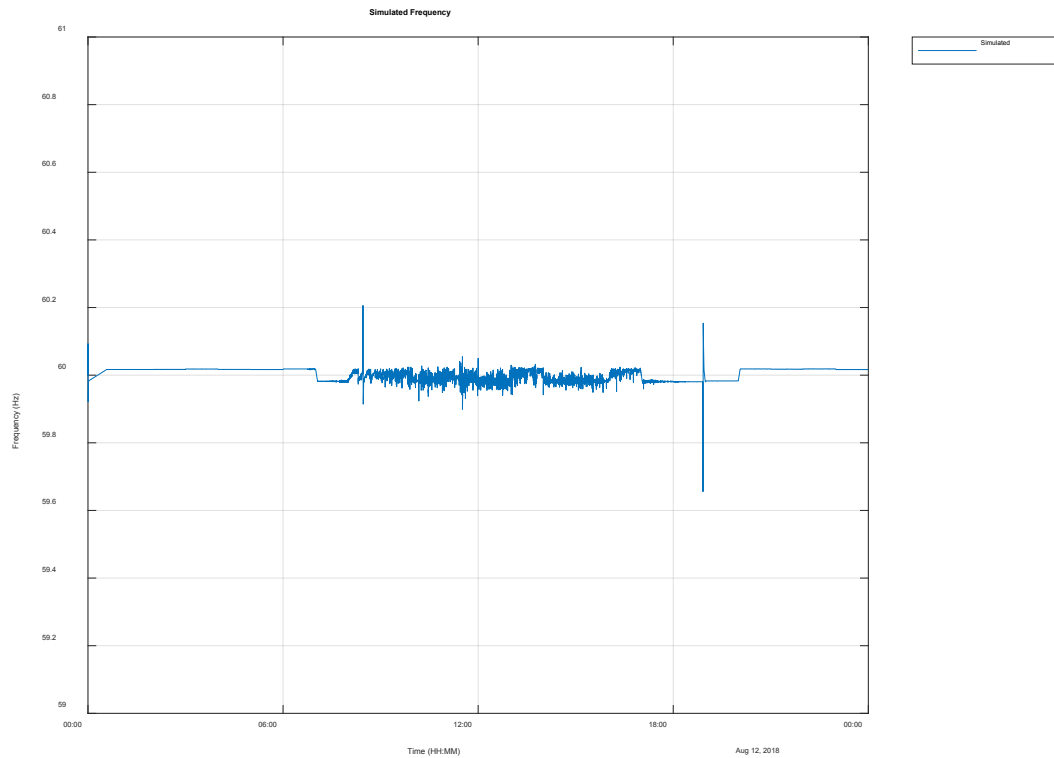
### 3.3.1 Base Case 1 & Simulation cases 1 – 6 Weekend (12 August 2018) with PV1 from 11 Mar 2017 & PV 2 from 16 Mar 2017

Base Case 1: Weekend (11 March 2017) - Simulation of original PV with PV1 from 11 Mar 2017 & PV 2 from 16 Mar 2017.

The original case is simulated to see if the GDAT model is a reasonably representative of the actual day. Figure 3-16 shows the simulation of generation unit outputs for Saturday 12 August 2018, with PV1 set at 0.4 MW & PV 2 set at 0.6 MW. Only the CAT units are on AGC to represent the current situation. 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 3-17, shows the expected frequency variations without the general noise from a varying demand. The improvement is which is due to fact that the simulation has the diesel units on AGC whilst in reality the diesel power station is controlling the frequency manually.

**Figure 3-16 Simulated generation on 12 August 2018 with current installed PV**



**Figure 3-17 Simulated frequency on weekend with current installed PV****Case 1: Weekend (12 August 2018) - 3 MW of PV**

For Case 1 the PV power plants are set to 1.5 MW each giving a total PV of 3 MW, CAT diesel units perform the frequency control, as shown in Figure 3-18. The frequency is acceptable but there are frequency excursions where the CAT Diesel Power plant is starting to struggle to control the frequency with high PV penetration and variation, as shown in Figure 3-19. When diesel unit is at minimum generation the PV is backed off to control frequency which does not happen in this case.

Figure 3-18 Simulated generation on weekend with 3 MW PV

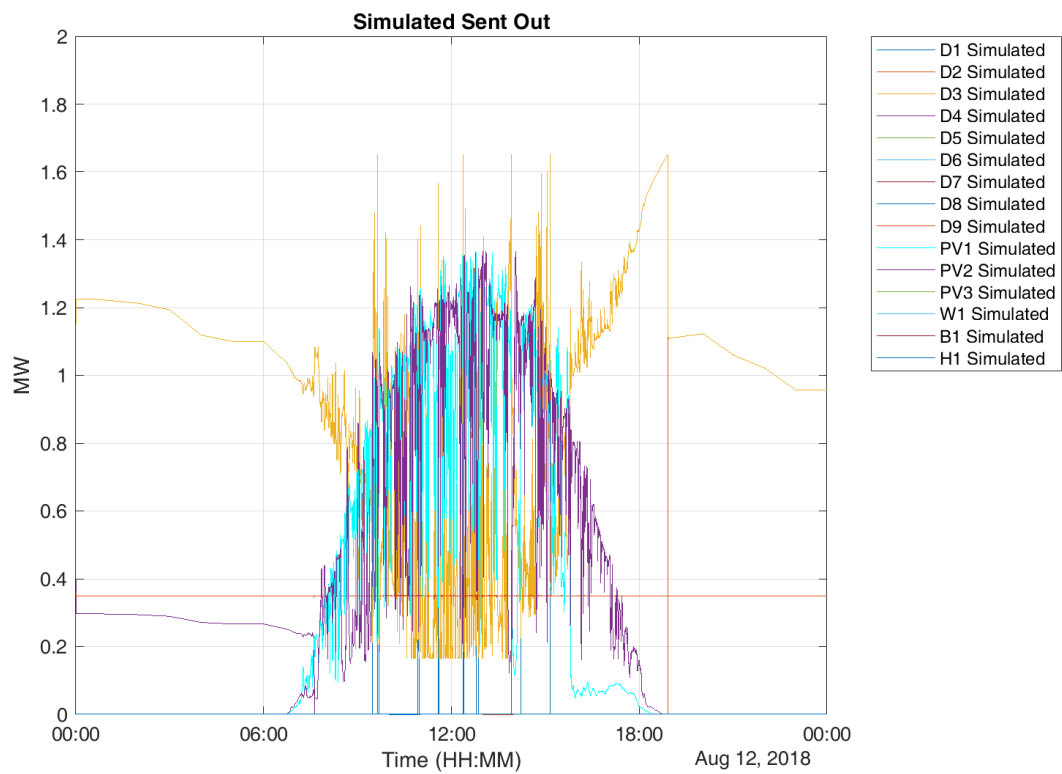
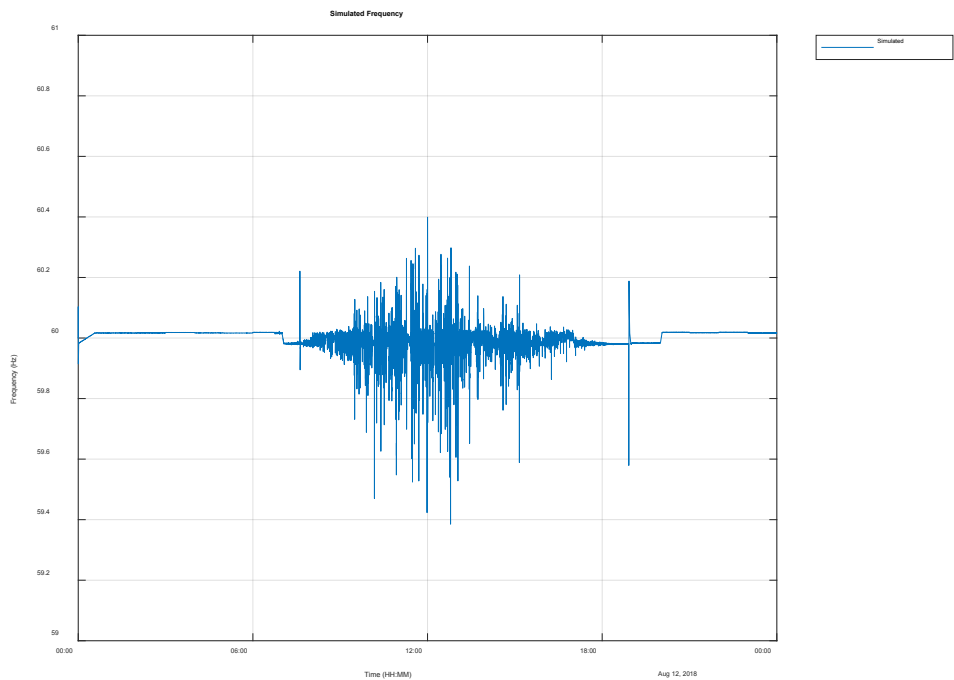


Figure 3-19 Simulated frequency on weekend with 3 MW PV



Case 2: Weekend (12 August 2018) - 3 MW of PV and 1 MW / 1 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 3-20. The deadband is set to 0.1 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 59.9 to 59.85 Hz and similarly will go to from 0 to full charge with a frequency variation from 60.1 to 60.15 Hz.

A 1 MW / 1 MWh battery costs US\$ \$104,910 per annum or US\$ 287.43 per day.

**Figure 3-20 Battery parameters when on primary frequency control only**

B1	
MCR	1
Unit Inertia	0
Ramp Rate	30
Maximum Generation	1
Minimum Generation	-1
Spinning Capability	1
Nonspinning Capability	0
AGC On	<input type="checkbox"/>
Model Name	Battery
Frequency Deadband	1.0000e-03
Lower Frequency Limit	-1
Upper Frequency Limit	1
Droop	1.0000e-03

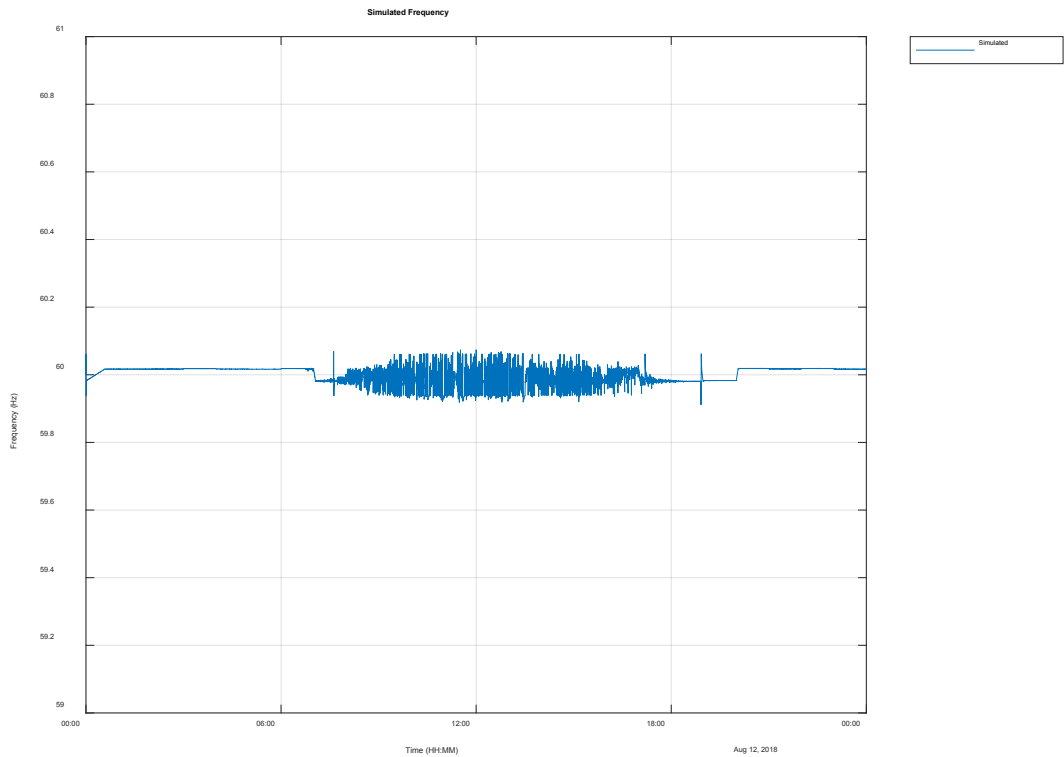
B1	
Initial Battery Charge (...)	0.5000
Maximum Power Supp...	1
Maximum Charge Cap...	3600
Minimum Charge Cap...	360
Charge Response Rat...	30
Discharge Response ...	-30

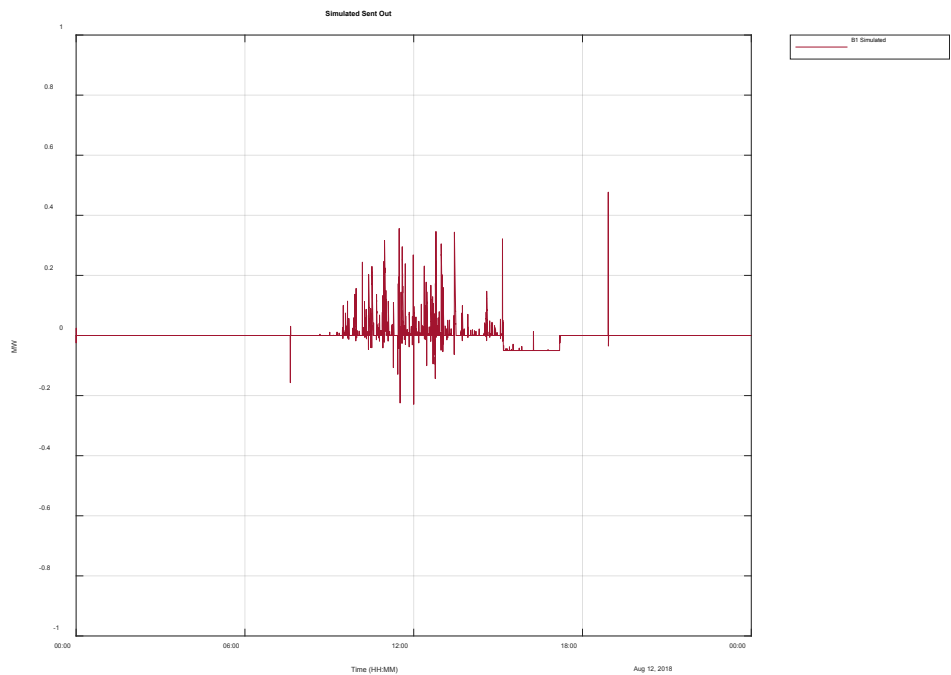
B1	
Megawatts	[0 1 2 3 10]
Cost	[1 1 1 1 1]

The simulated frequency improves when 1 MW battery is on primary frequency control only, as shown in Figure 3-21. The battery is utilised for half its output and the response is enough to prevent frequency excursions, as shown in Figure 3-22. The diesel fuel costs remain the same at \$16,805 as for case 1 showing the battery is just performing primary frequency control and the battery on discharges a few percent. The net saving of US\$ 873 is calculated for the simulation day including the battery costs.

**Figure 3-21 Simulated frequency for weekend with 3 MW of PV and 1 MW / 1 MWh battery on primary frequency control**



**Figure 3-22 Simulated battery power for weekend with 3 MW of PV and 1 MW / 1 MWh battery on primary frequency control**



Case 3: Weekend (12 August) - 6 MW of PV and 2 MW / 2 MWh battery on primary frequency control

For Case 3 the PV power plants are set to 3 MW each giving a total PV of 6 MW, all diesel units provides the secondary control under AGC to perform the control assisted by a 2 MW battery on AGC, as shown in Figure 3-23. The batteries also provide primary frequency control as for the simulations above. The philosophy for the batteries under AGC control is:

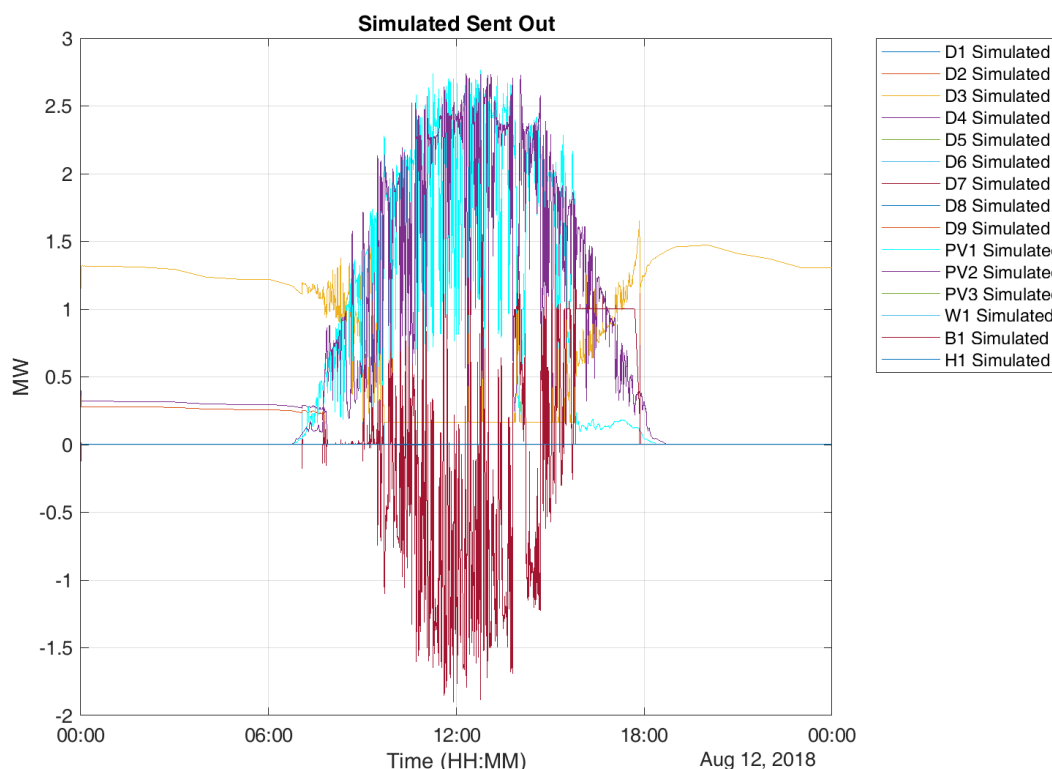
1. Starting batteries with a charge of 20% - assuming batteries have been utilised the previous evening – update to actual midnight value to give a typical continuous day's profile (need to run simulation twice)
2. Battery is discharged whenever possible to displace diesel. Battery provide power at half 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

The frequency is acceptable control well within the range of 59.5 to 60.5 Hz, as shown in

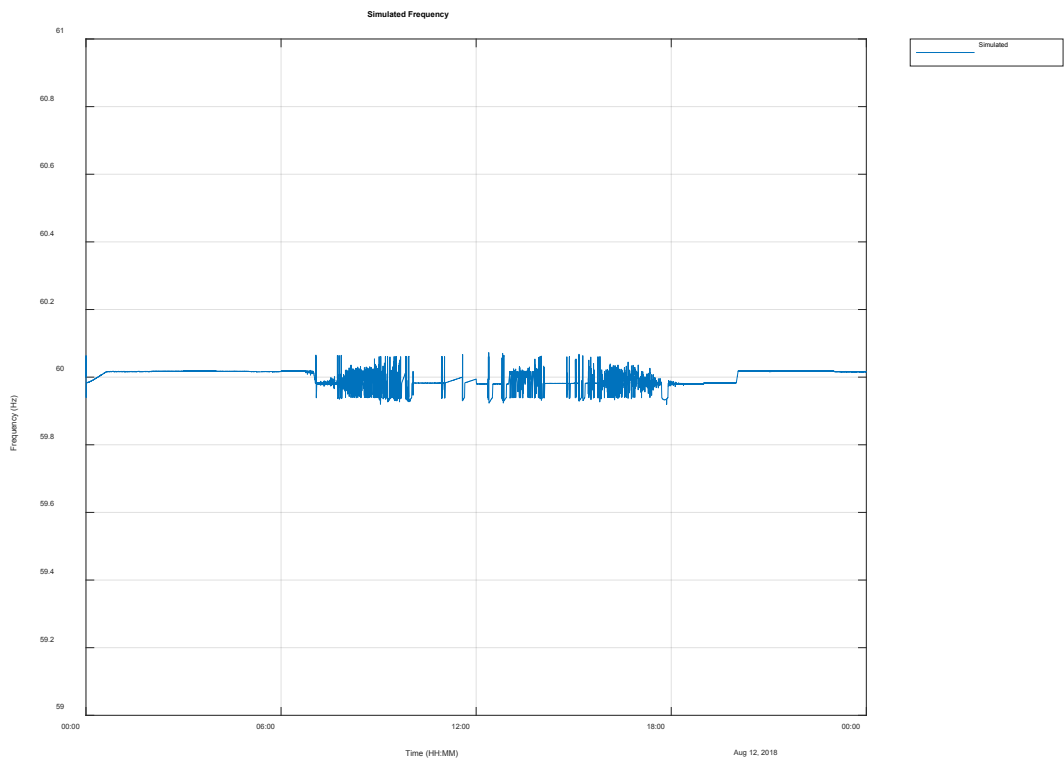
Figure 3-24. The battery full range is not fully utilised to control the frequency and so battery size is fine for frequency control for this simulation case with the battery charging to 80%, as shown in Figure 3-25.

All of the available energy from the 6 MW of PV is used resulting which results in a fuel saving of US\$5,139 and a net saving of US\$ 2,133 for the simulation day.

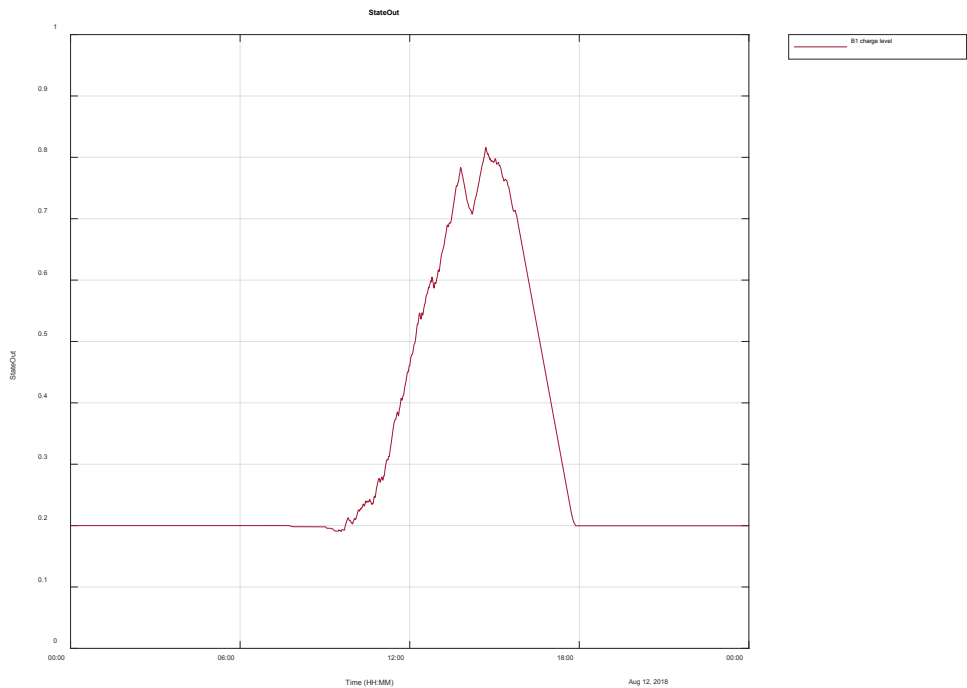
**Figure 3-23 Simulated generation for weekend with 6 MW of PV and 2 MW / 2 MWh battery on AGC and primary frequency control**



**Figure 3-24 Simulated frequency for weekend with 6 MW of PV and 2 MW / 2 MWh battery on AGC and primary frequency control**



**Figure 3-25 Simulated battery charge for weekend with 6 MW of PV and 2 MW / 2 MWh battery on AGC and primary frequency control**



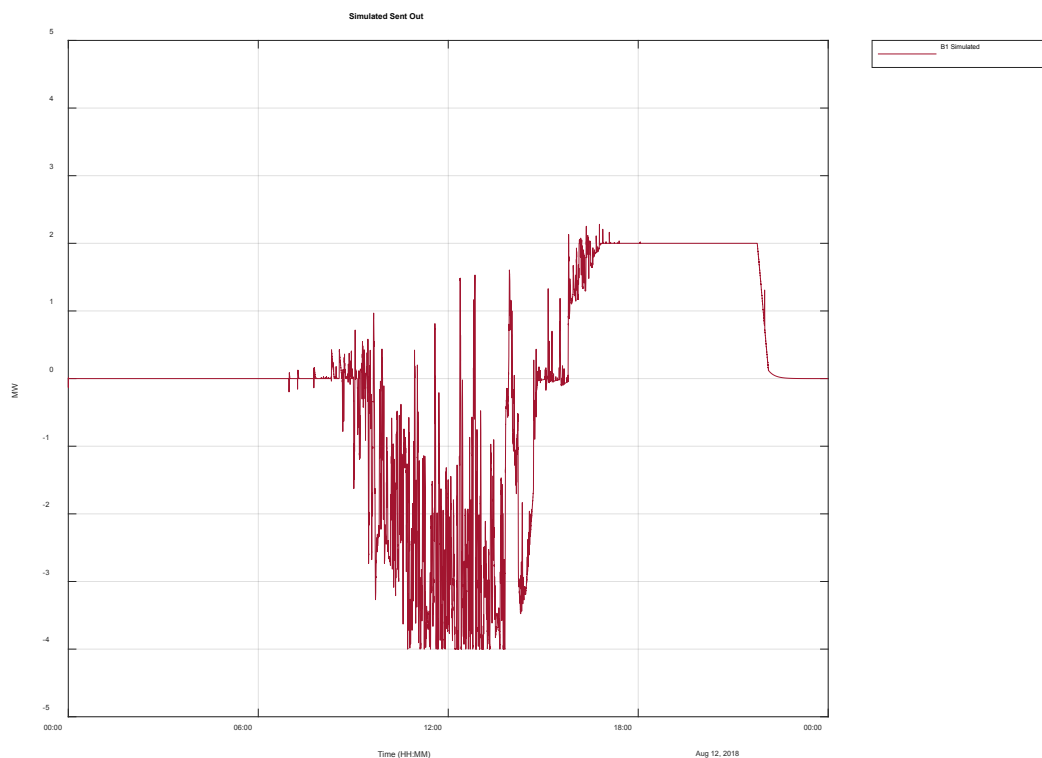
Case 4: Weekend (12 August 2018) - 9 MW of PV and 4 MW / 4 MWh battery on AGC

Case 4 is simulating an increase the PV to 9 MW and doubling the battery to 4 MW / 4 MWh on AGC.

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, by 15:00. The batteries then discharge instead of using diesel generation from 16:00 Hrs until charge level is 20% which is around 22:00. The simulated diesel generator 1 output is at minimum generation for most of the period from 10:00 Hrs to 17:30 Hrs, as shown in Figure 3-28.

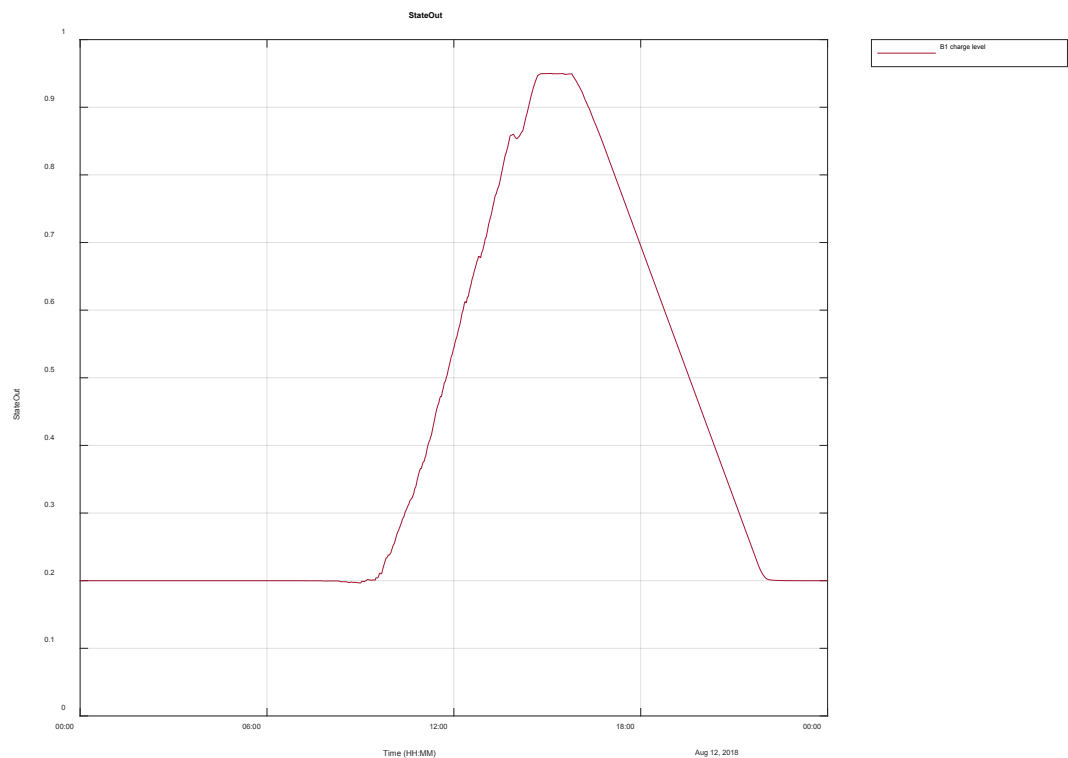
The daily fuel savings for Case 4 is \$ 8,019 compared to \$ 5,139 for Case 3. This increase is due to an increase PV output of 14 MWh and this case has a net savings of \$ 2,980 for the simulation day.

**Figure 3-26 Simulated battery output for weekend when 4 MW / 4 MWh battery provides both primary frequency control and AGC with 9 MW of PV.**

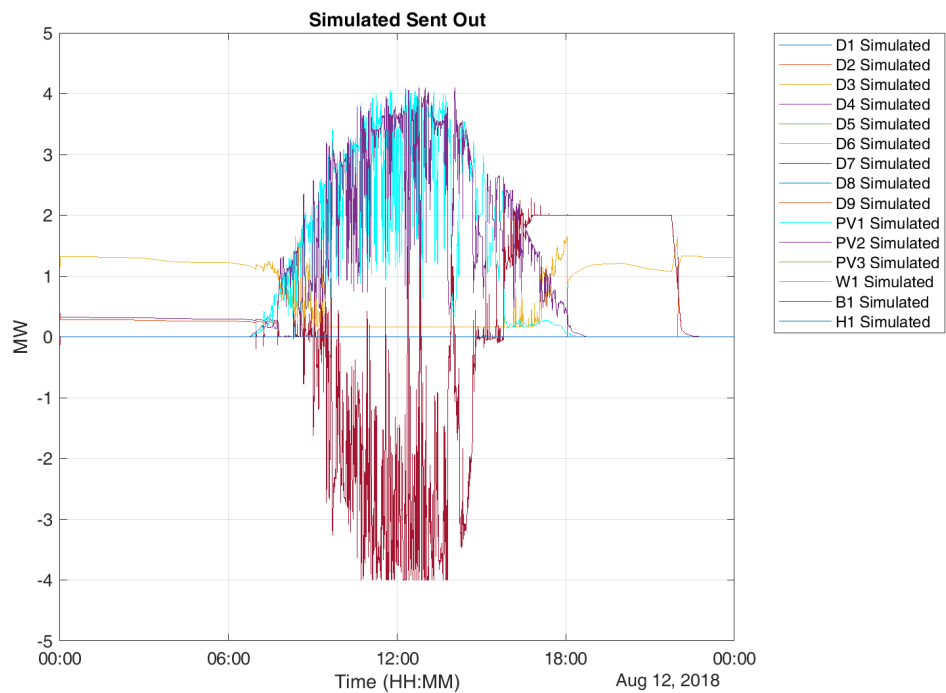




**Figure 3-27 Simulated battery charge level for weekend when 4 MW / 4 MWh battery provides both primary frequency control and AGC with 9 MW of PV.**



**Figure 3-28 Simulated generator outputs for weekend when 4 MW / 4 MWh battery provides both primary frequency control and AGC with 9 MW of PV.**



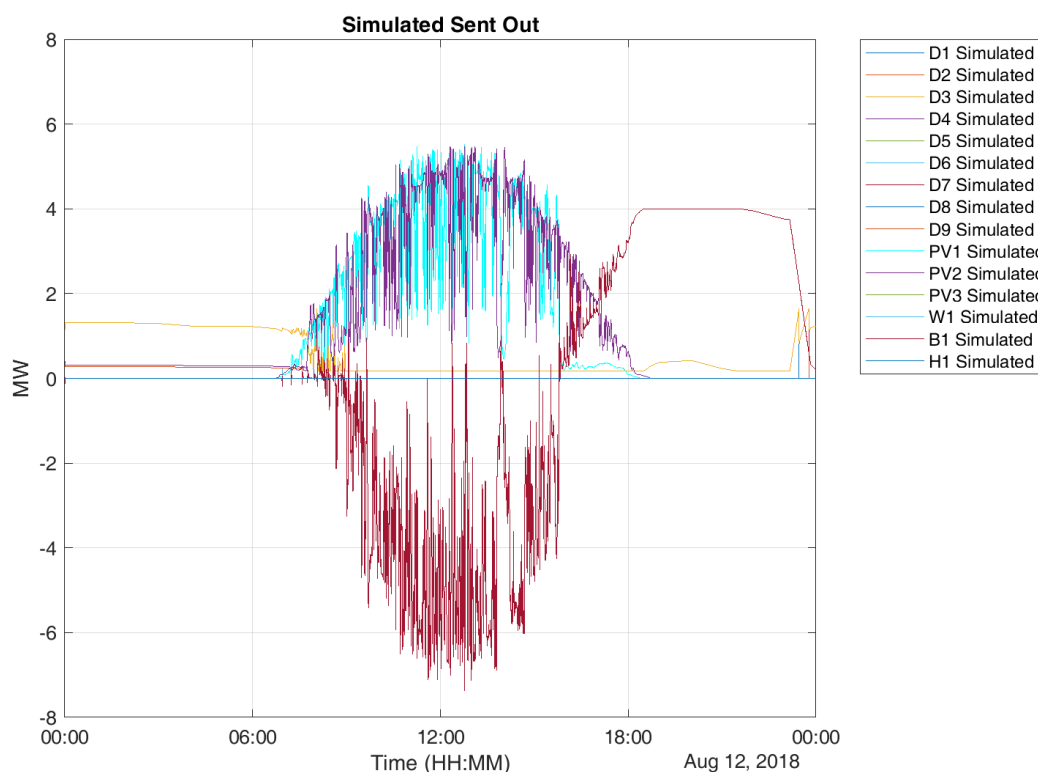
**Case 5: Weekend (12 August 2018) - 12 MW of PV and 8 MW / 8 MWh battery on AGC**

This case is where the PV is increased to 12 MW and an 8 MW / 8 MWh battery is on AGC and primary frequency control. The simulated generation, as shown in Figure 3-29 that shows that the inverter size required of 8 MW is just sufficient.

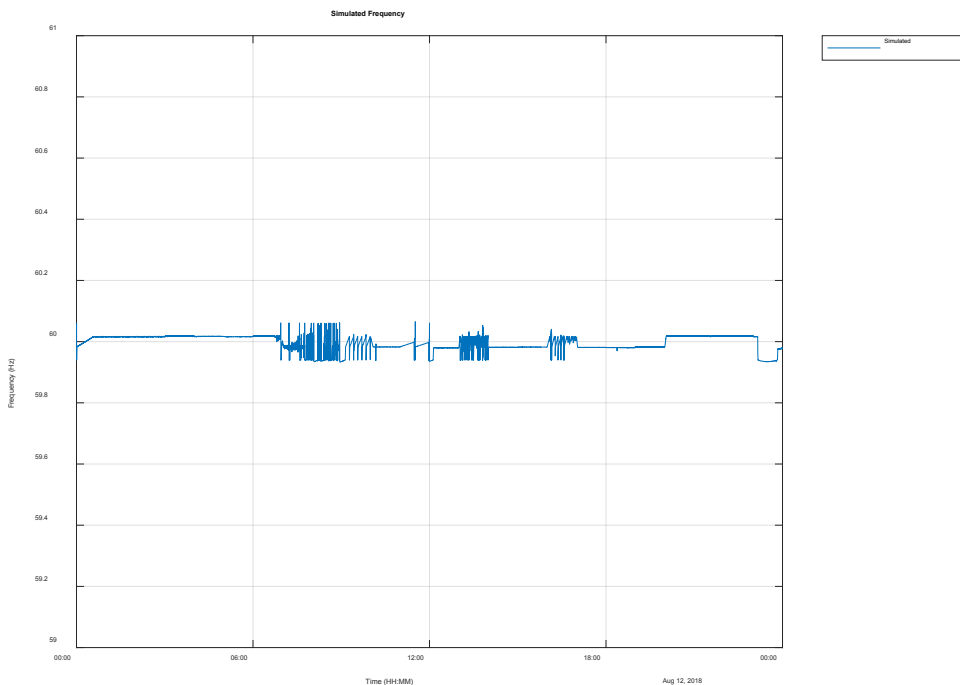
The simulated frequency is within acceptable limits, as shown in Figure 3-29.. There are a no frequency excursions which means the inverter size is adequate, as shown in Figure 3-31. The battery charges to 60% by 16:00 and fully discharges by 24:00, as shown in Figure 3-31.

The energy from PV is nearly all utilised and thus the battery is adequately sized for this simulation day. This case has a net saving of \$ 3,922 for the simulation day.

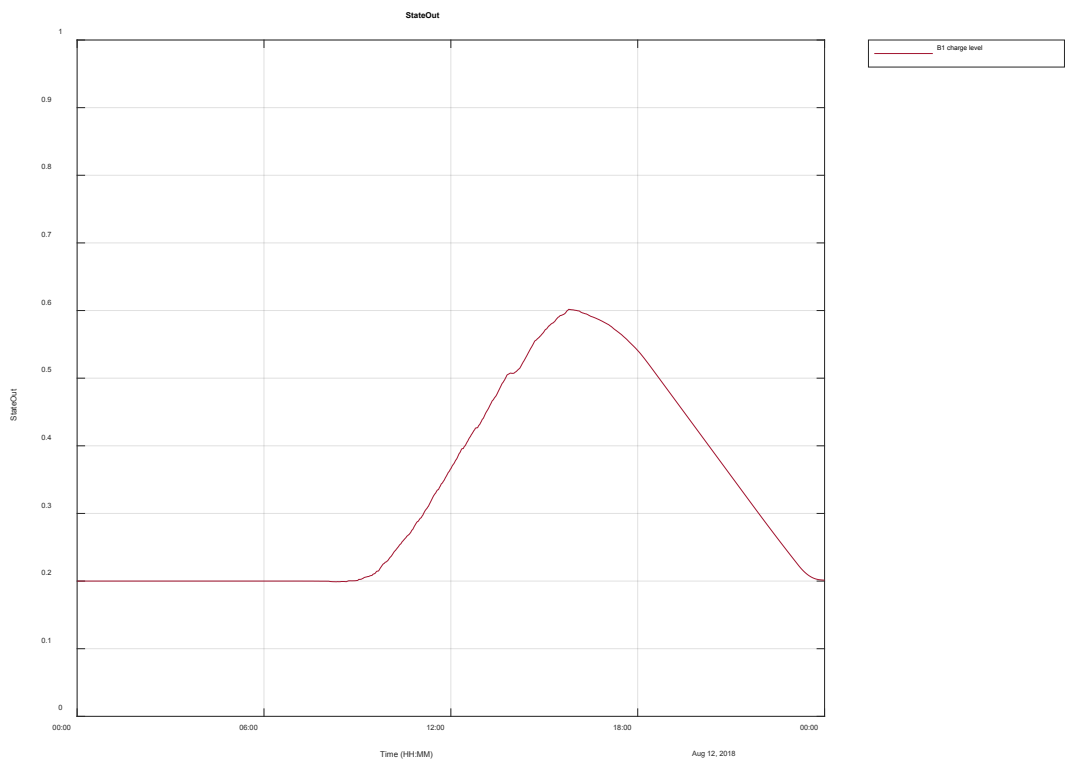
**Figure 3-29 Simulated generator output for weekend when 8 MW/ 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV. All diesel units allowed to go off.**



**Figure 3-30 Simulated frequency for weekend when 8 MW / 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV.**



**Figure 3-31 Simulated battery charge for weekend when 8 MW / 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV.**



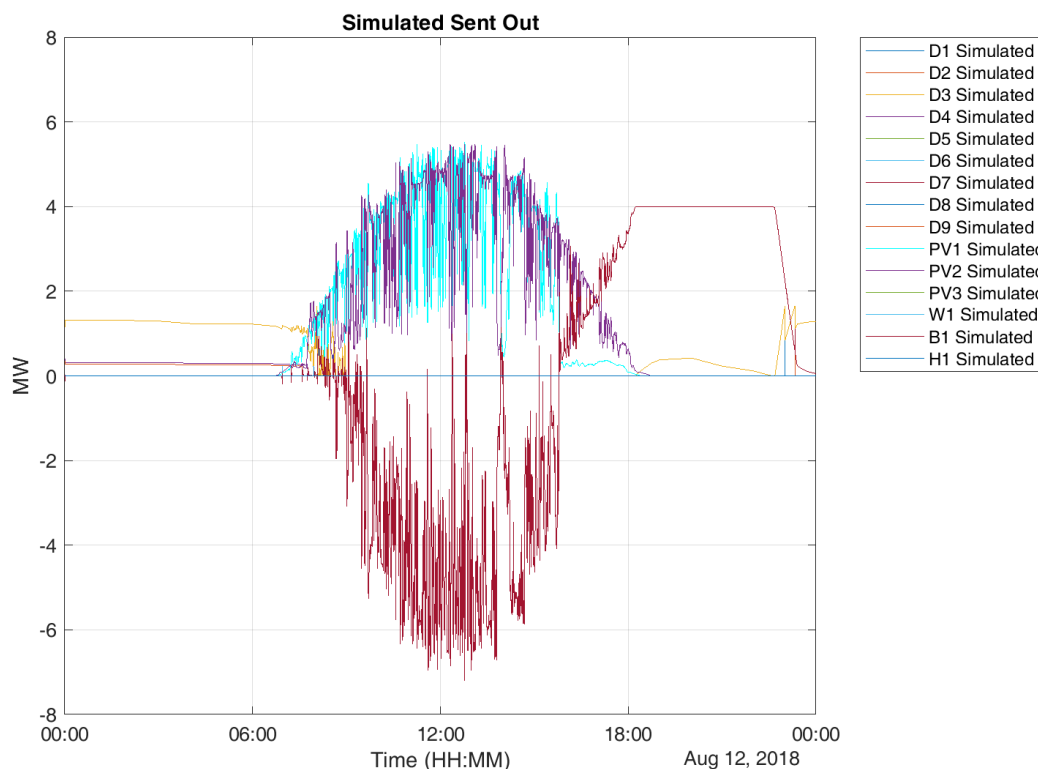
**Case 6: Weekend (12 August 2018) - 12 MW of PV and 8 MW / 8 MWh battery on AGC and all diesel off**

This case is a repeat of Case 5 but now the last diesel unit is allowed to go off line. In case 5 the 0.6 MWh of PV power is spilt which equates to 1.0 % of energy lost. Figure 3-32 shows that all diesel generators are off from 10:00 to 18:00.

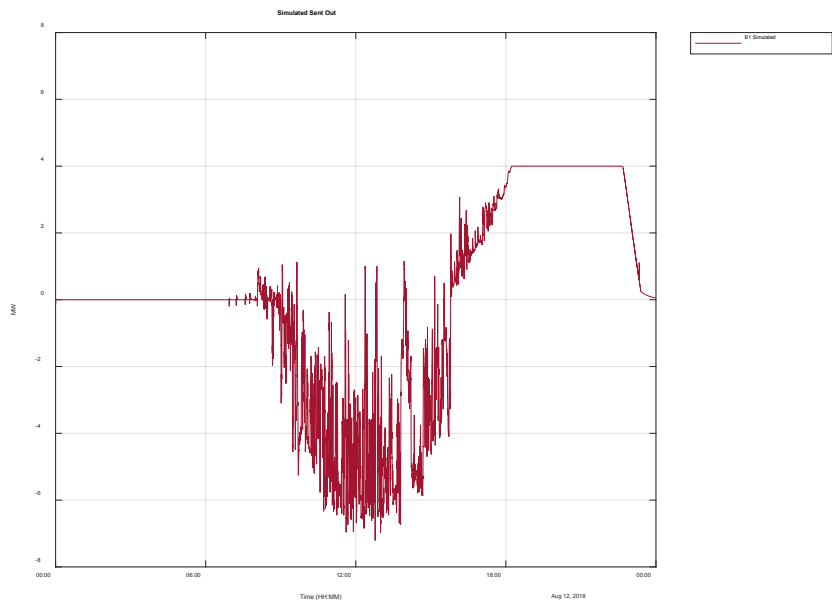
Figure 3-33 shows the when battery simulated outputs when put on primary frequency control and AGC, the batteries use the excess PV to charge the battery to 60% of full charge, as shown in Figure 3-34, by 16:00. The batteries then discharge instead of using diesel generation from 16:00 Hrs until 23:30. No diesel is required for the simulation day. Figure 3-35 shows the simulated frequency which shows there is sufficient control range to control the frequency.

The fuel costs for Case 6 is \$113 lower than case 5 which is not much of a fuel saving when generator is switched off. A higher level of PV would be required to fully utilise batteries.

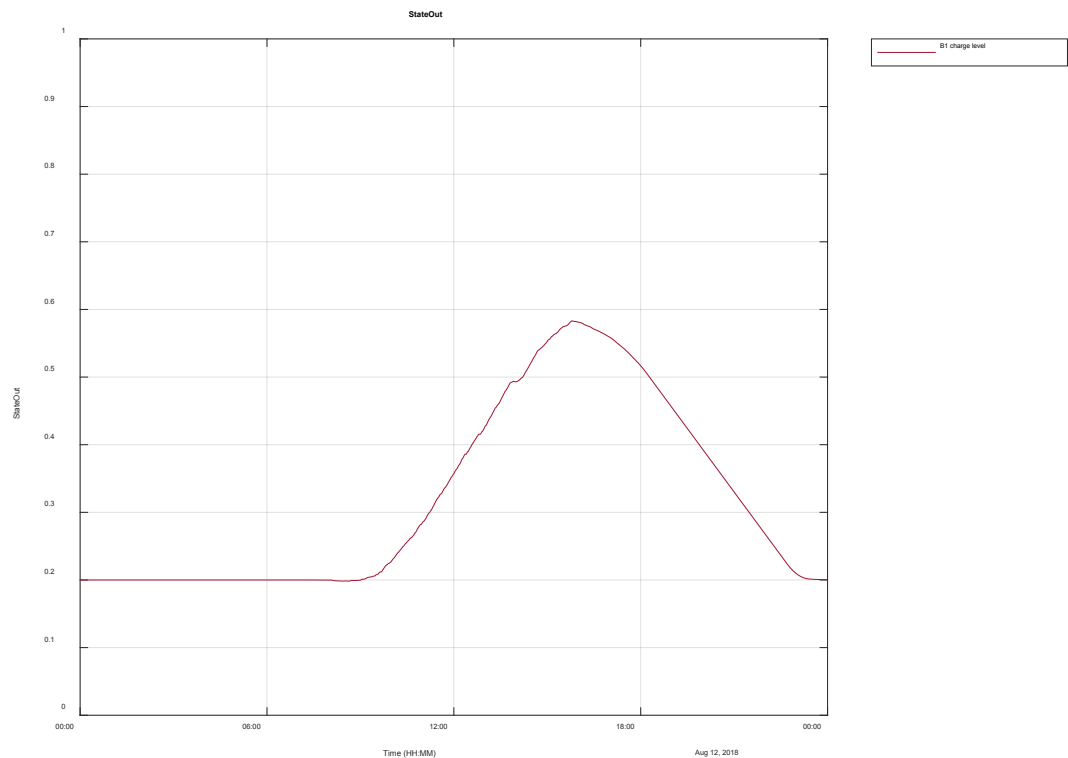
**Figure 3-32 Simulated generator output for weekend when 8 MW/ 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV. All diesel units allowed to go off.**



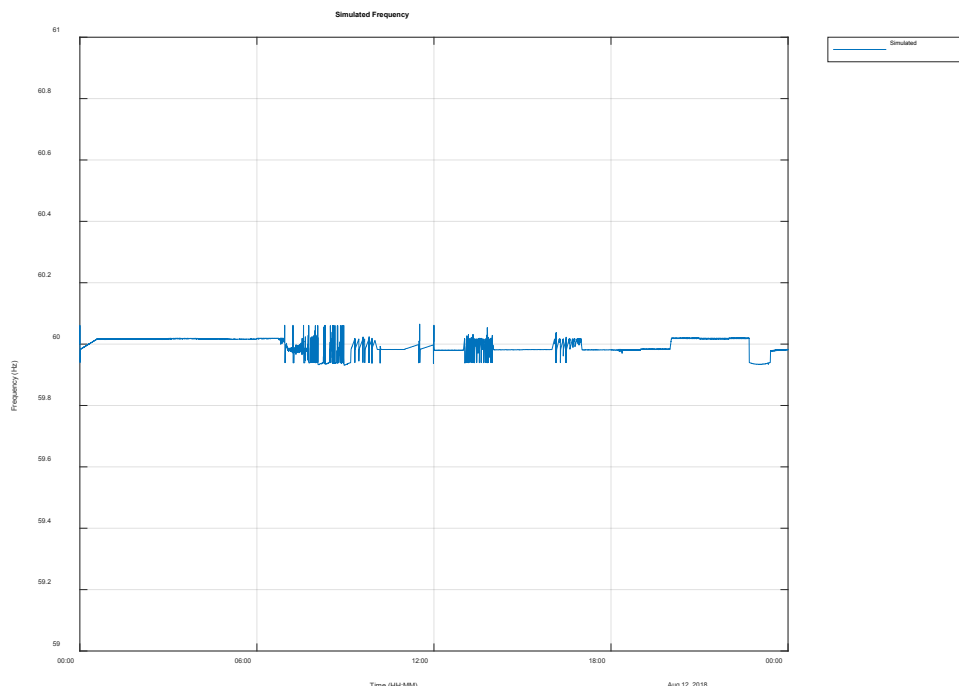
**Figure 3-33 Simulated battery output for weekend when 8 MW/ 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV. All diesel units allowed to switch off.**



**Figure 3-34 Simulated battery charge level for weekend when 8 MW/ 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV. All diesel units allowed to go off.**



**Figure 3-35 Simulated frequency for weekend when 8 MW/ 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV. All diesel units allowed to go off.**

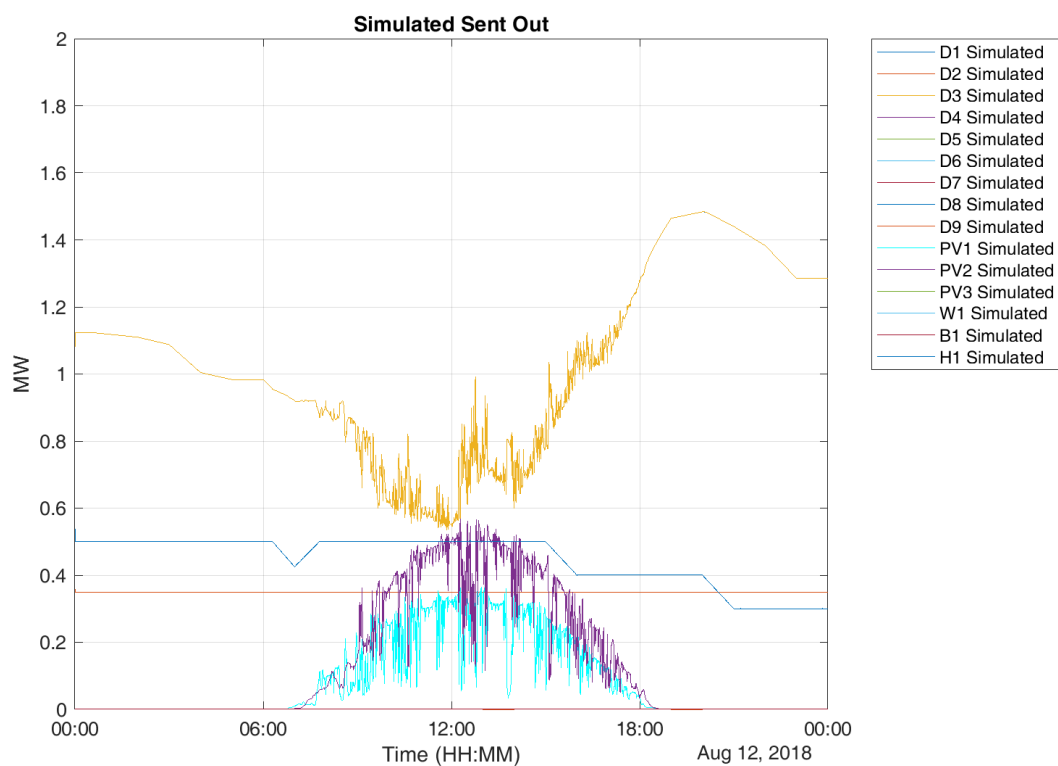
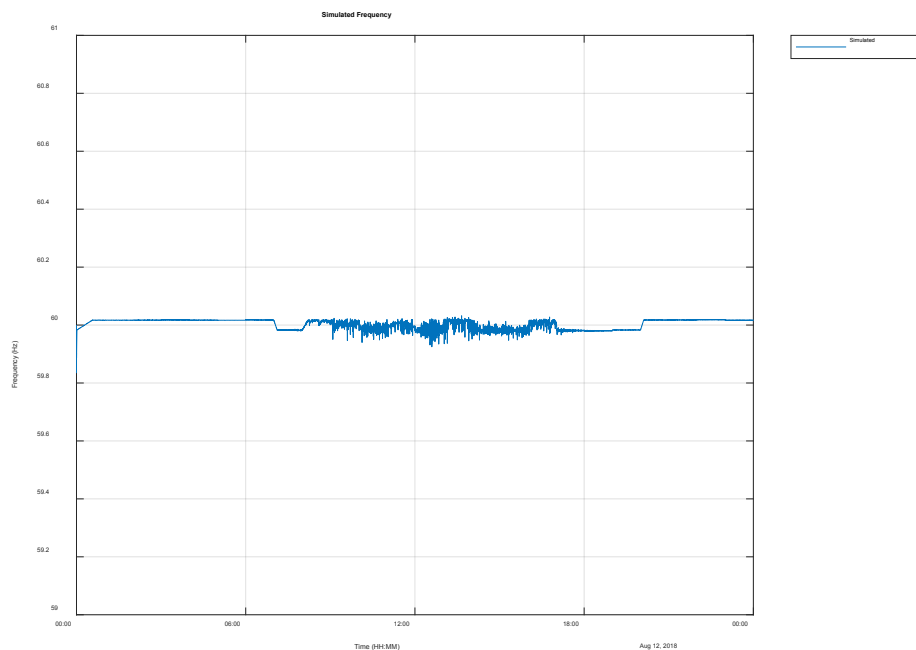


### 3.3.2 Base Case 2 & Simulation cases 7 – 12 (12 August 2018) with PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017

Base Case 2: Weekend (12 August 2018) - Simulation of original day with PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017 and with Hydro on.

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data.

Figure 3-36 shows the simulation of generation unit outputs for Sunday 12 August 2018, with PV1 of 0.4 MW from 14 March 17 and PV2 of 0.6 MW from 15 March 2017. For this base case and simulations the hydro generation is online, off AGC as it is not dispatchable as a run of river and output is as recorded on 8 August 2018. The CAT generators are only units on AGC. 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 3-37, is more or less what is expected with any second by second changes from demand.

**Figure 3-36 Simulated generation on weekend (12 August 2018) with current installed PV****Figure 3-37 Simulated frequency on weekend (12 August 2018) with current installed PV**

Case 7 - 12: Weekend (12 August 2018) – Repeat of cases 1-6 PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017 and hydro data from 8 August 2018.

Cases 7 – 12 is the repeat of the simulations for a typical weekend but with PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017. The simulated frequency is within an acceptable range for case 7 with 3 MW total PV simulated, as shown in Figure 3-38, but the simulated frequency control is worse with the more volatile PV variations. Case 9 with 6 MW of simulated PV with a 2 MW / 2 MWh battery on primary frequency control results in an acceptable frequency control, as shown in Figure 3-39. Case 10 with 9 MW of simulated PV with a 4 MW / 4 MWh battery on AGC also results in an acceptable frequency control, as shown in Figure 3-40. Case 12 with the 12 MW of PV and 8 MW / 8 MWh battery on AGC has a very similar same result as for case 6 except battery is charge slightly more, as shown in Figure 3-41.

The fuel savings for the same scenario for the weekend cases is very similar except the PV production for the cases 7 -12 was slightly less than for cases 1-6 so daily fuel and net savings are lower.

**Table 3-5 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
<b>3 MW PV and no battery</b>	2,133	2,123	1,161	1,098
<b>3 MW PV and 1 MW / 1 MWh battery on gov</b>	2,133	2,127	873	815
<b>6 MW PV and 2 MW / 2 MWh battery on gov</b>	5,139	4,770	2,133	1,634
<b>9 MW PV and 4 MW / 4 MWh battery on AGC</b>	8,019	7,460	2,980	2,212
<b>12 MW PV and 8 MW / 8 MWh battery on AGC</b>	11,569	12,478	3,922	4,543
<b>12 MW PV and 8 MW / 8 MWh battery on AGC and all diesel allowed to go off</b>	11,643	12,565	3,995	4,630



Figure 3-38 Case 7 - Simulated frequency on weekend with 3 MW PV

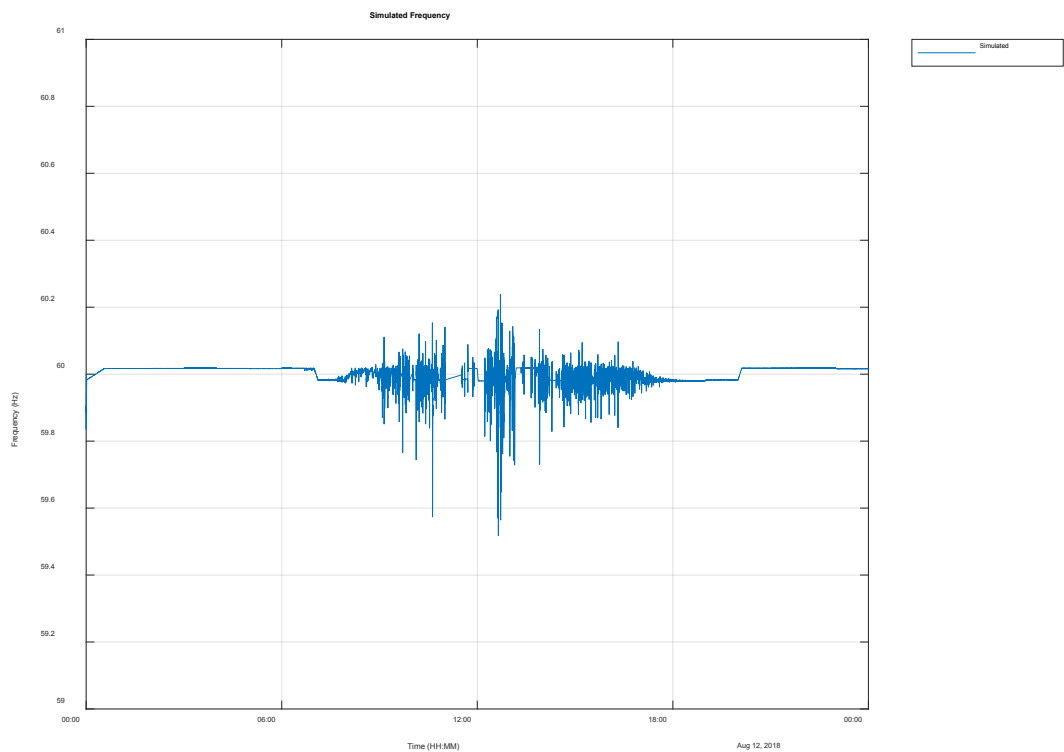


Figure 3-39 Case 9 - Simulated frequency on weekend with 6 MW PV and 2 MW / 2 MWh battery on primary frequency control

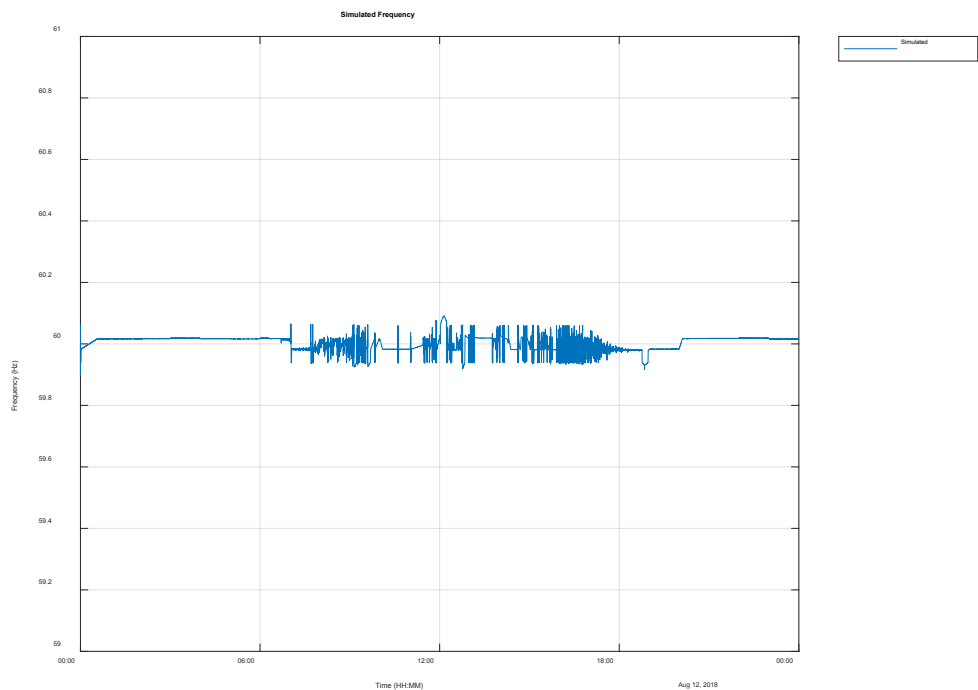


Figure 3-40 Case 10 - Simulated frequency on weekday with 9 MW PV and 4 MW / 4 MWh battery on AGC.

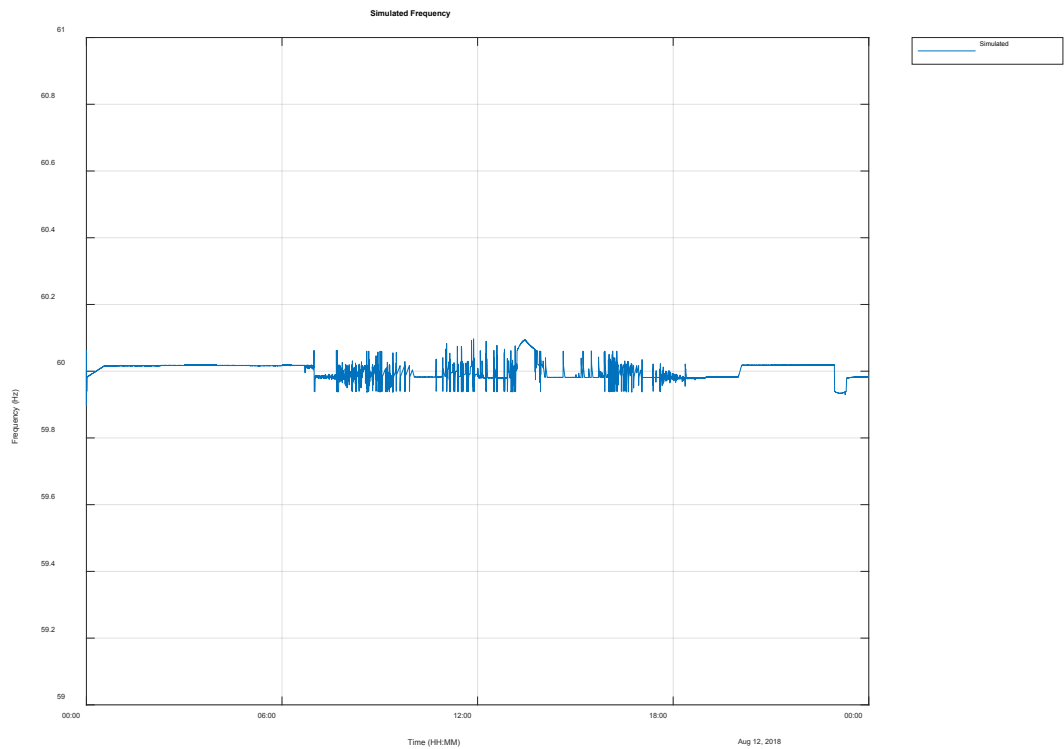
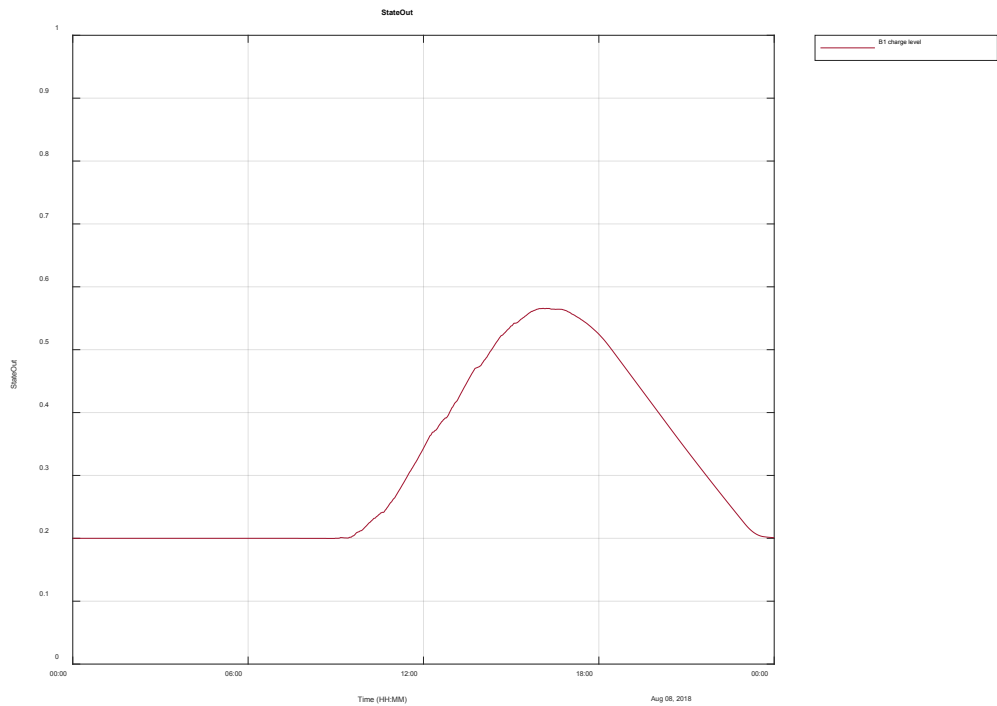


Figure 3-41 Case 12 - Simulated charge level on weekend with 12 MW PV and 8 MW /8 MWh battery on AGC and all diesel units off.

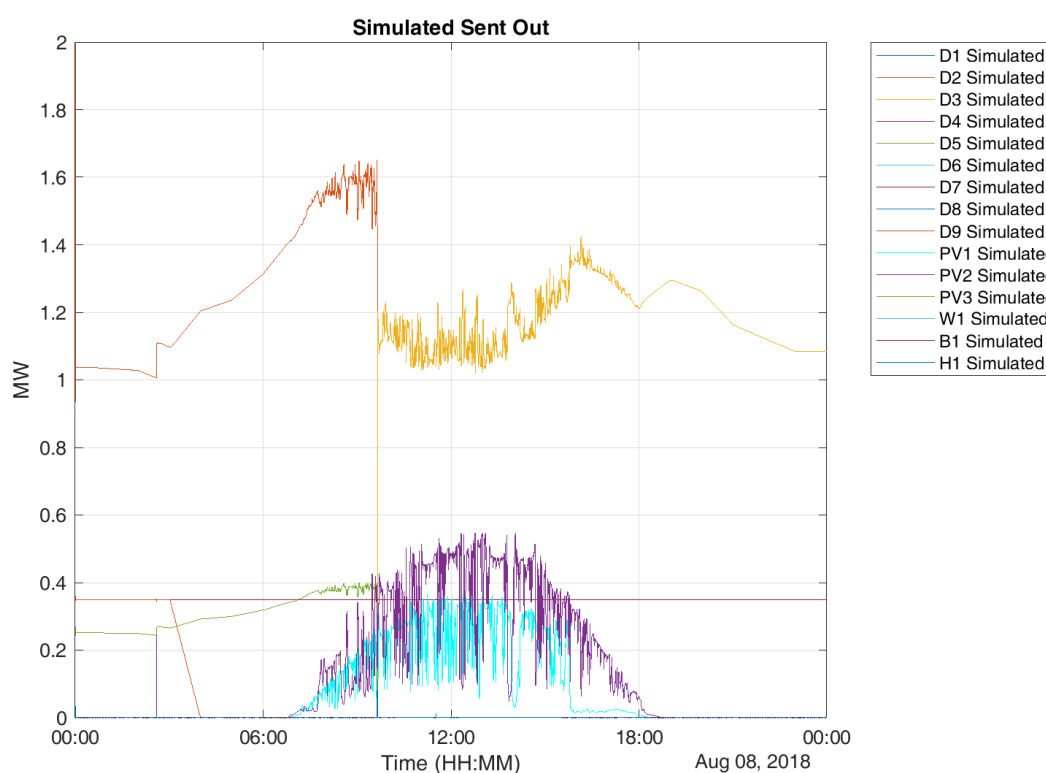


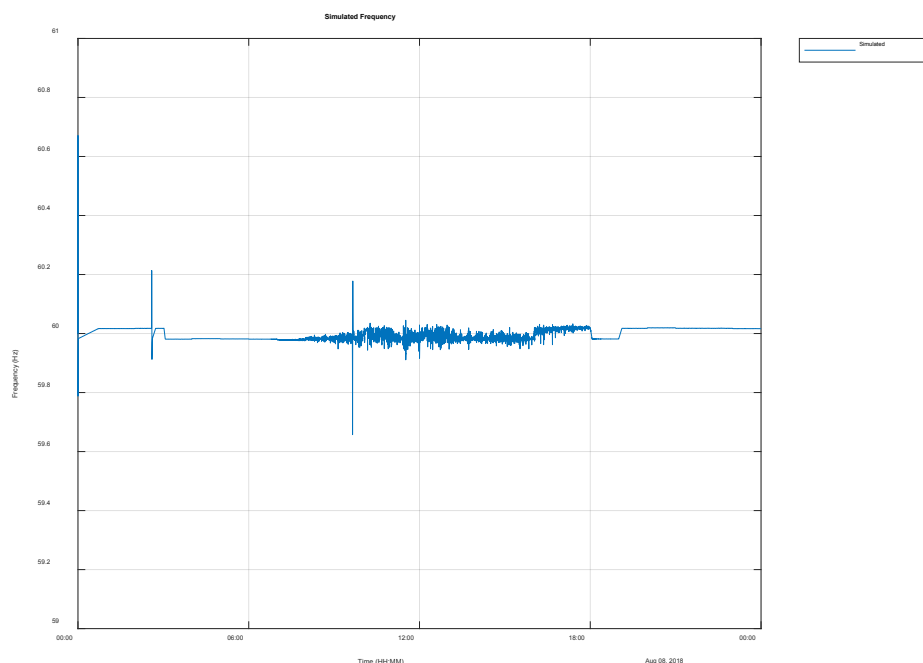
### 3.3.3 Base Case 3 & Simulation cases 13 – 18 Weekday (8 Aug 2018) with PV1 from 11 Mar 2017 & PV 2 from 16 Mar 2017

#### Base Case 3: Weekday (8 August 2018) - Simulation of original with PV1 from 11 Mar 2017 & PV 2 from 16 Mar 2017

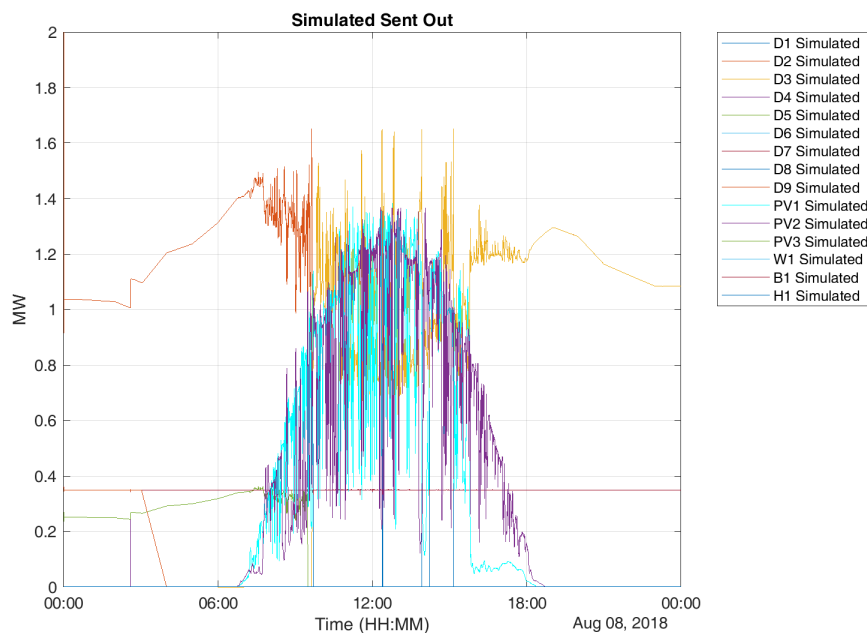
The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data. Figure 3-42 shows the simulation of generation unit outputs for Wednesday 8 August 2017, with 0.4 MW from PV1 from 11 Mar 2017 (representing the town plants) & 0.6 MW from PV 2 (representing Pohnlanga PV) from 16 Mar 2017. Only the CAT generators are on AGC as is the current situation. 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 3-43, shows the expected frequency variations which are typical for this amount of PV.

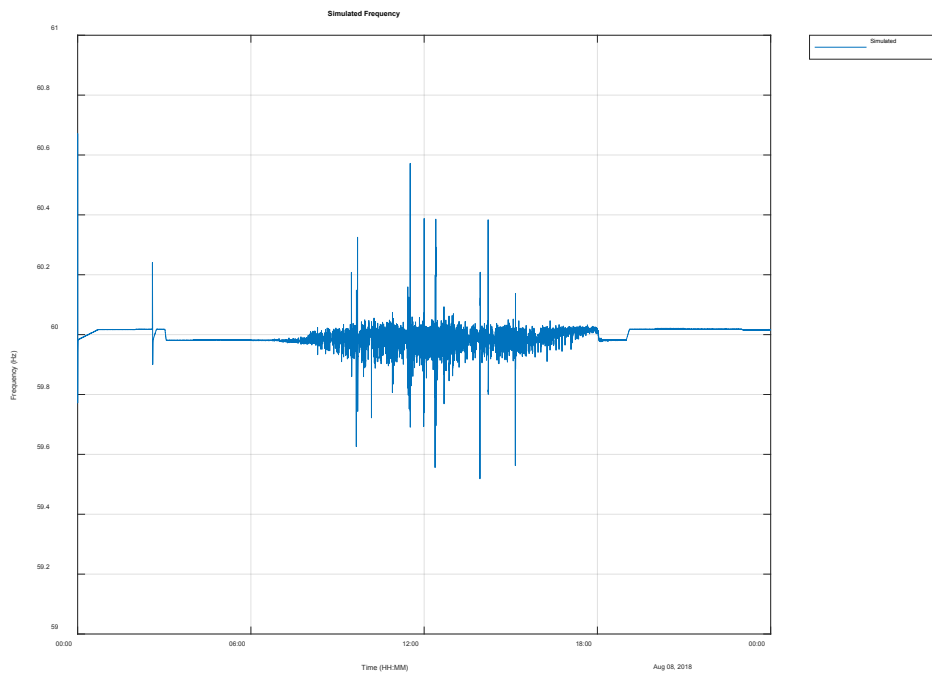
**Figure 3-42 Simulated generation on weekday with current installed PV**



**Figure 3-43 Simulated frequency on weekday with current installed PV****Case 13: Weekday (8 August 2018) - 3 MW of PV**

For Case 13 the PV power plants are set to 1.5 MW each giving a total PV of 3 MW, CAT diesel units are the units on to perform frequency control, as shown in Figure 3-44. The frequency is acceptable but there are frequency excursions where the Diesel Power plant is battling to control the frequency.

**Figure 3-44 Simulated generation on weekday with 3 MW PV**

**Figure 3-45 Simulated frequency on weekday with 3 MW PV****Case 14: Weekday (8 August 2018) - 3 MW of PV and 1 MW / 1 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 3-46.

The deadband is set to 0.1 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 59.9 to 59.85 Hz and similarly will go to from 0 to full charge with a frequency variation from 60.1 to 60.15 Hz.

**Figure 3-46 Battery parameters when on primary frequency control only**

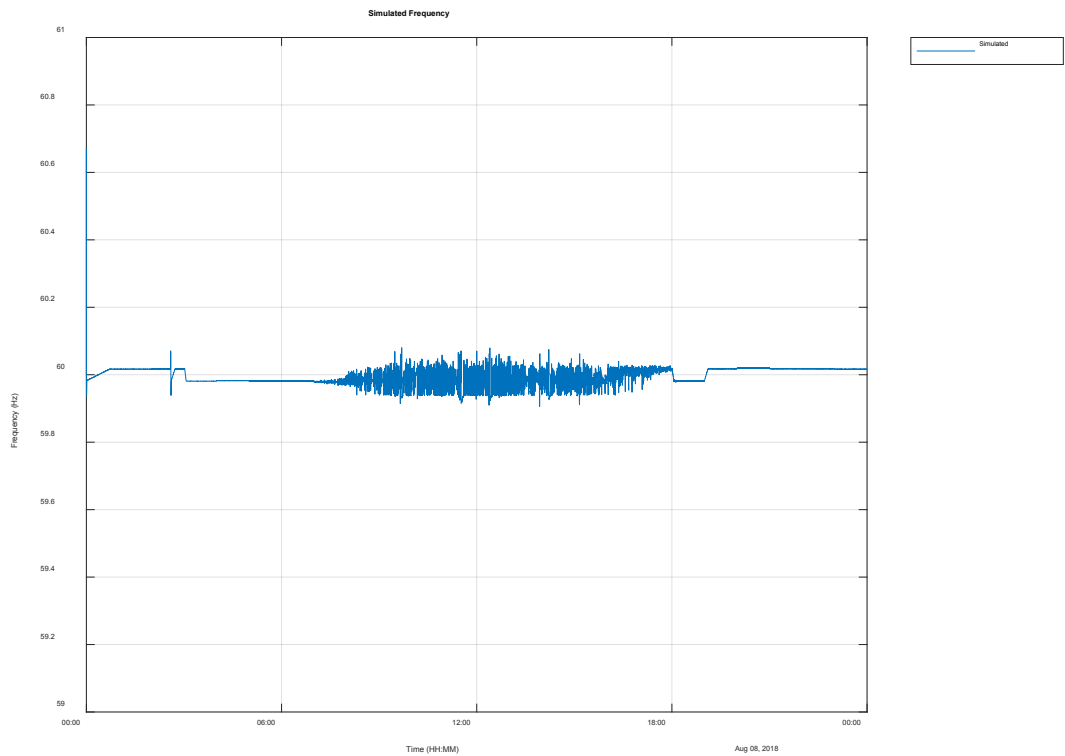
Power Generation Dispatch - C:\PPA\saexample\Projects\Pohnpei\Pohnpei\_3MWPV\_1MW\_1MWh\_Batt.mat

File View Simulation

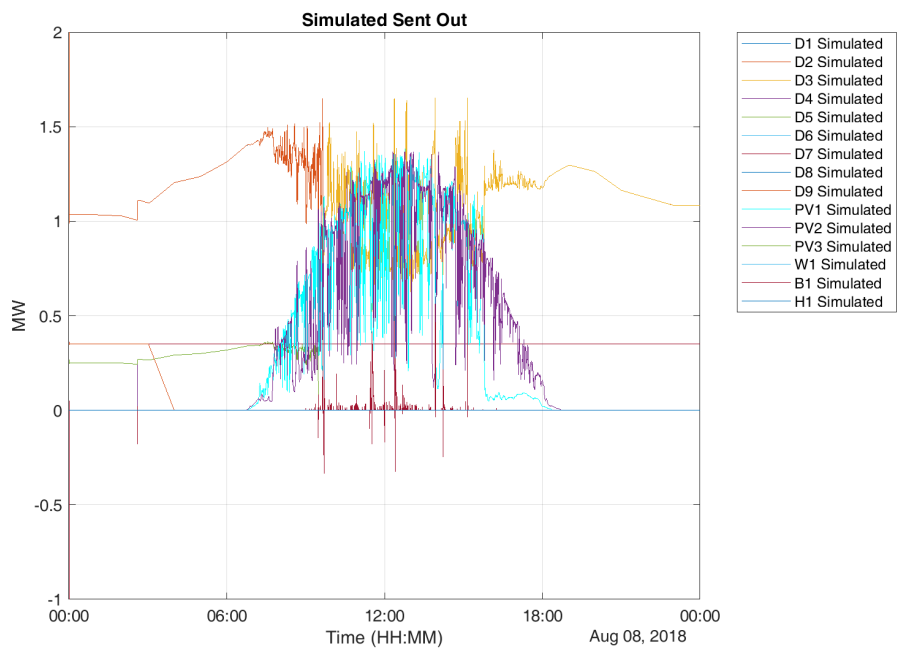
Diesel	PV	Wind	Batt	Hydro
B1				
MCR				1
Unit Inertia				0
Ramp Rate				30
Maximum Generation				1
Minimum Generation				-1
Spinning Capability				1
Nonspinning Capability				0
AGC On			<input type="checkbox"/>	
Model Name			Battery	
Frequency Deadband				1.0000e-03
Lower Frequency Limit				-1
Upper Frequency Limit				1
Droop				1.0000e-03
B1				
Initial Battery Charge (...)				0.5000
Maximum Power Supp...				1
Maximum Charge Cap...				3600
Minimum Charge Cap...				360
Charge Response Rat...				30
Discharge Response ...				-30
B1				
Megawatts	[0 1 2 3 10]			
Cost	[1 1 1 1 1]			

The simulated frequency improves when 1 MW battery is on primary frequency control only, as shown in Figure 3-47. The battery is sufficient to prevent the few frequency excursion, as shown in Figure 3-48. The diesel fuel costs remain almost the same at \$19,425 as for case 13 showing the battery is just performing primary frequency control and the battery on discharges a few percent. The net saving of US\$ 875 is calculated for the simulation day including the battery costs.

**Figure 3-47 Simulated frequency for weekday with 3 MW of PV and 1 MW / 1 MWh battery on primary frequency control**



**Figure 3-48 Simulated generation for weekday with 3 MW of PV and 1 MW / 1 MWh battery on primary frequency control**



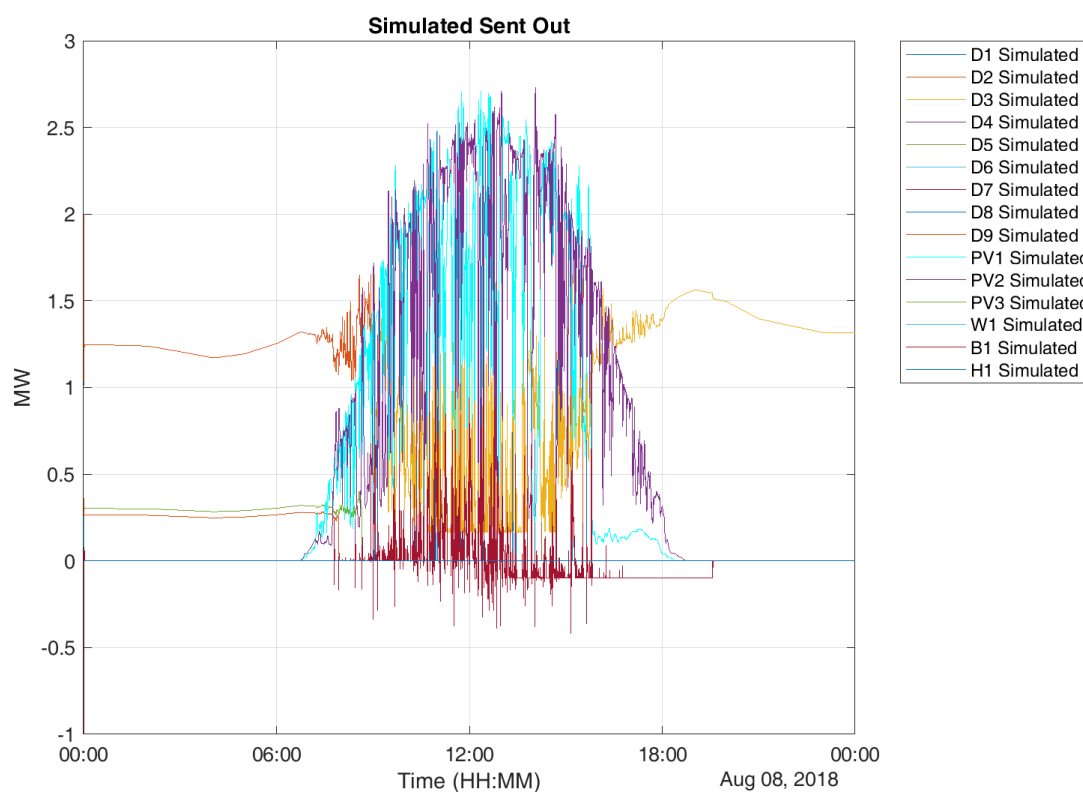
**Case 15: Weekday (16 March 2017) - 6 MW of PV and 2 MW / 2 MWh battery on primary frequency control**

For Case 15 the PV power plants are set to 3 MW each giving a total PV of 6 MW, all diesel units provides the secondary control under AGC to perform the control assisted by a 2 MW / 2 MWh 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.

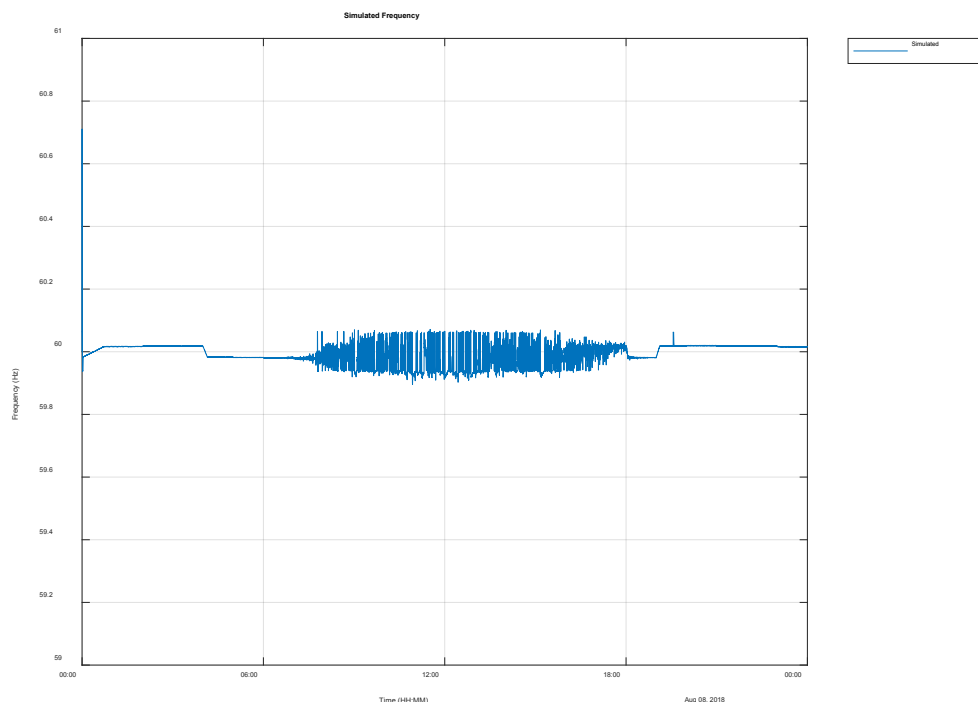
Nearly all of the available energy from the 6 MW of PV is used resulting in a fuel saving of US\$5,027 and a net saving of US\$ 2,021 for the simulation day.

**Figure 3-49 Simulated generation for weekday with 6 MW of PV and 2 MW / 2 MW battery on primary frequency control**





**Figure 3-50 Simulated frequency for weekday with 6 MW of PV and 2 MW / 2 MWh battery on primary frequency control**



**Case 16: Weekday (8 August 2018) – 9 MW of PV and 2 MW / 2 MWh battery on AGC**

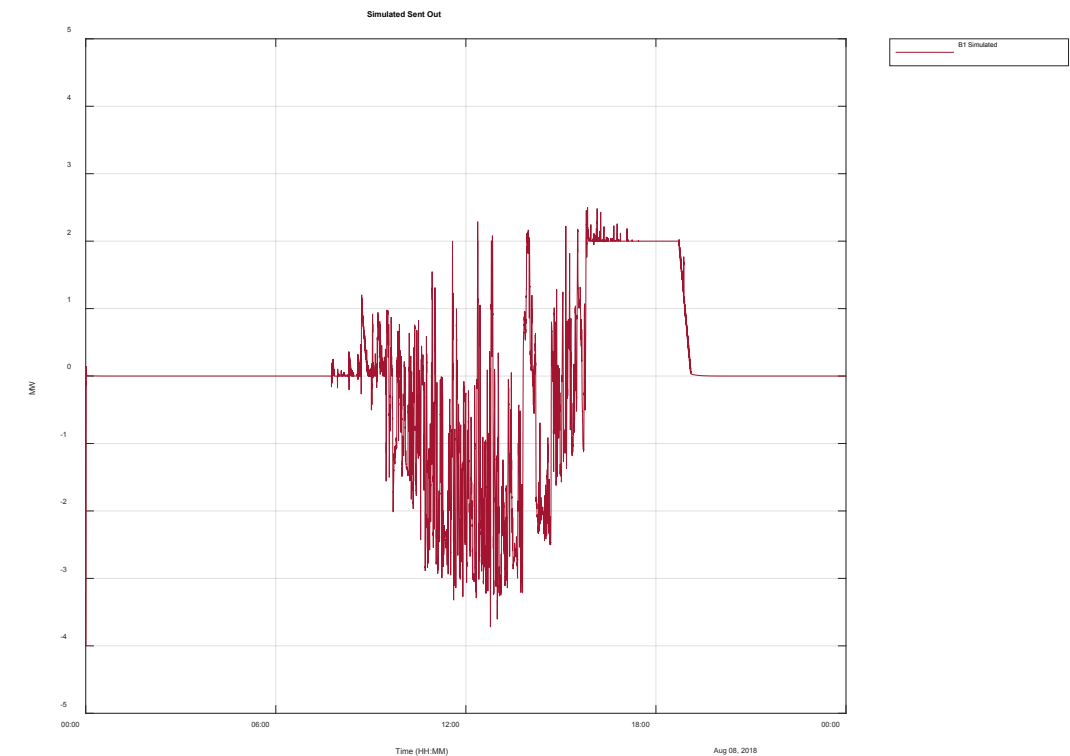
Case 16 is simulating the same as Case increasing the PV to 9 MW and on AGC. The batteries also provide primary frequency control as for the simulations above. The philosophy for the batteries under AGC control is:

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

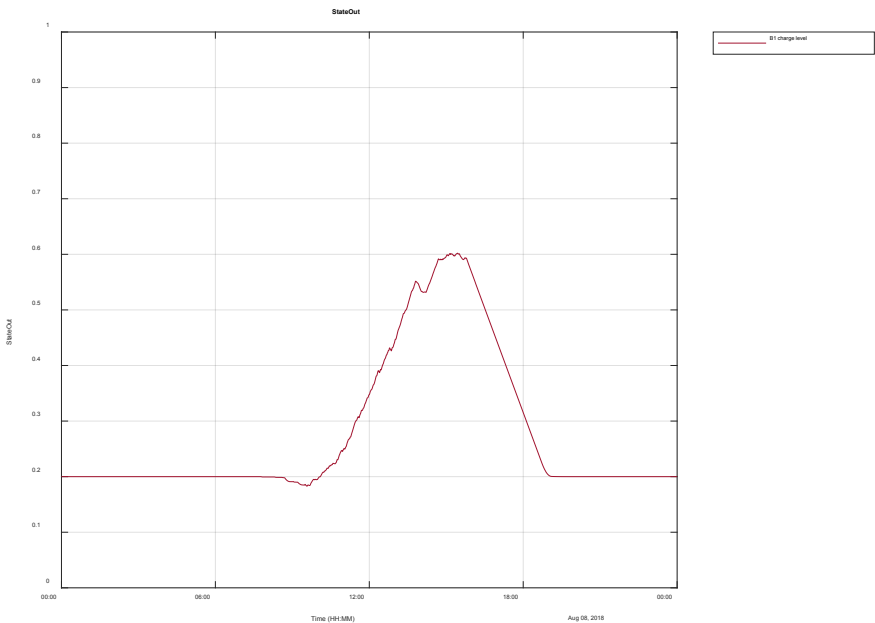
Figure 3-51 shows the when battery simulated outputs when put on primary frequency control and AGC, the batteries use the excess PV to charge the battery 60% charge level, as shown in Figure 3-52, by 15:00. The batteries then discharge instead of using diesel generation from 16:00 Hrs until charge level is 20% which is around 18:30. The simulated diesel generator 1 output is at minimum generation for most of the period from 10:00 Hrs to 16:30 Hrs, as shown in Figure 3-53.

The fuel savings for Case 16 is \$ 8,375 compared to \$ 5,027 for Case 15. This reduction is due to an increase PV output of 14.4 MWh and this case has a net saving of \$ 3,386.

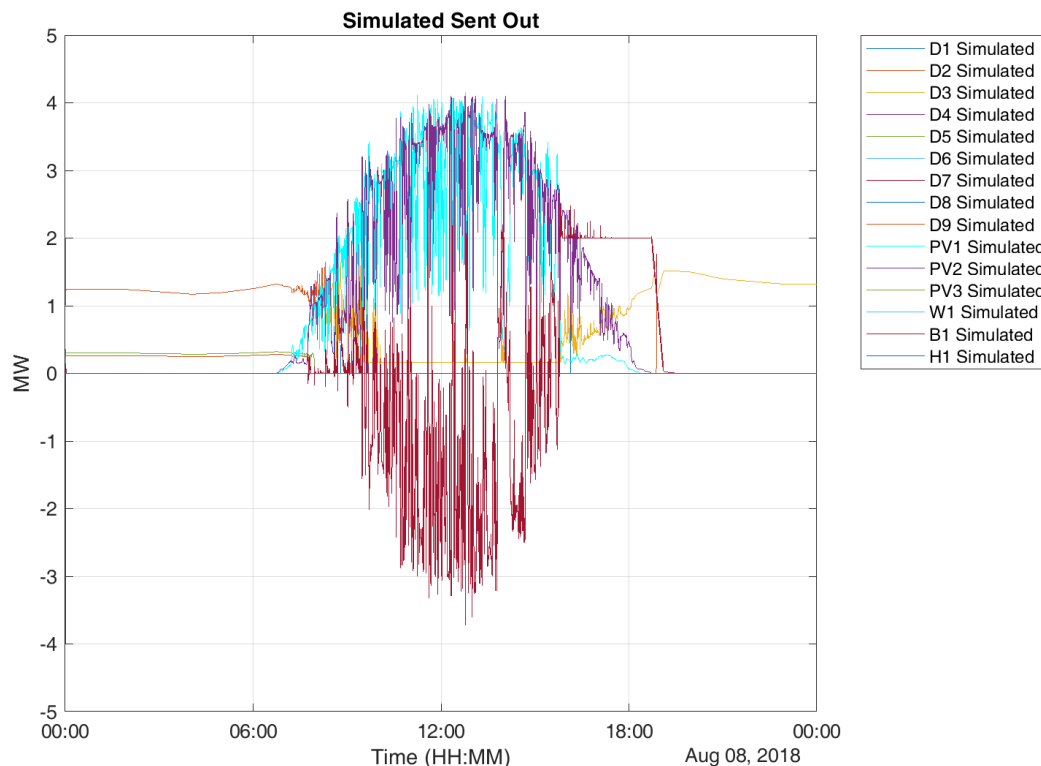
**Figure 3-51 Simulated battery output for weekday when 4 MW / 4 MWh battery provides both primary frequency control and AGC with 9 MW of PV.**



**Figure 3-52 Simulated battery charge level for weekday when 4 MW / 4 MWh battery provides both primary frequency control and AGC with 9 MW of PV.**



**Figure 3-53 Simulated generator outputs for weekday when 4 MW / 4 MWh battery provides both primary frequency control and AGC with 9 MW of PV.**



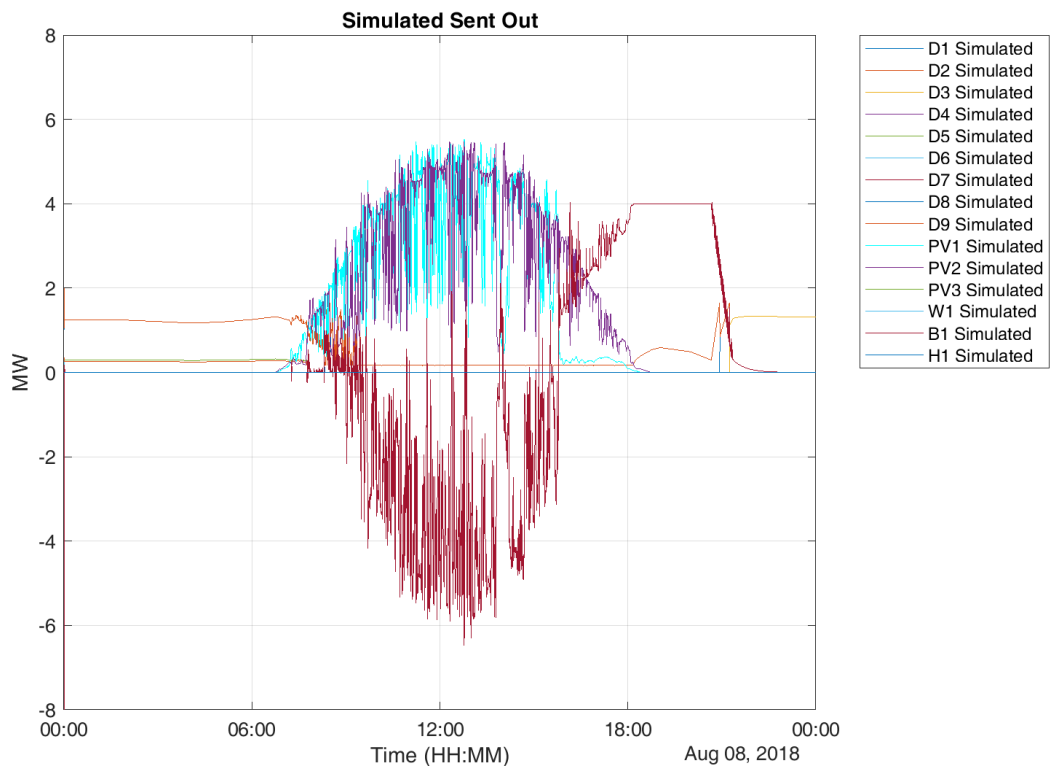
**Case 17: Weekday (8 August) – 12 MW of PV and 8 MW / 8 MWh battery on AGC**

This case is where the PV is increased to 12 MW and an 8 MW / 8 MWh battery is on AGC and primary frequency control. The simulated generation, as shown in Figure 3-54., shows that the inverter size is more than sufficient.

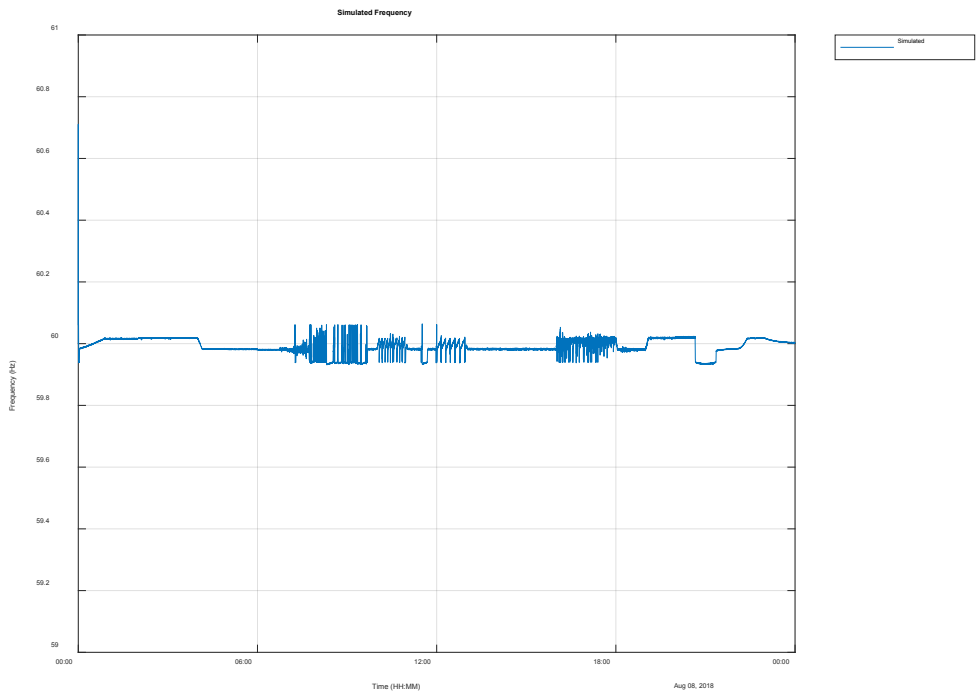
The simulated frequency is within acceptable limits, as shown in Figure 3-55. The battery charges to 50% by 16:30 and fully discharges by 20:00, as shown in Figure 3-56.

The energy is nearly fully utilised and thus the battery is adequately sized for this simulation day. This case has a net saving of \$ 3,957 for the simulation day.

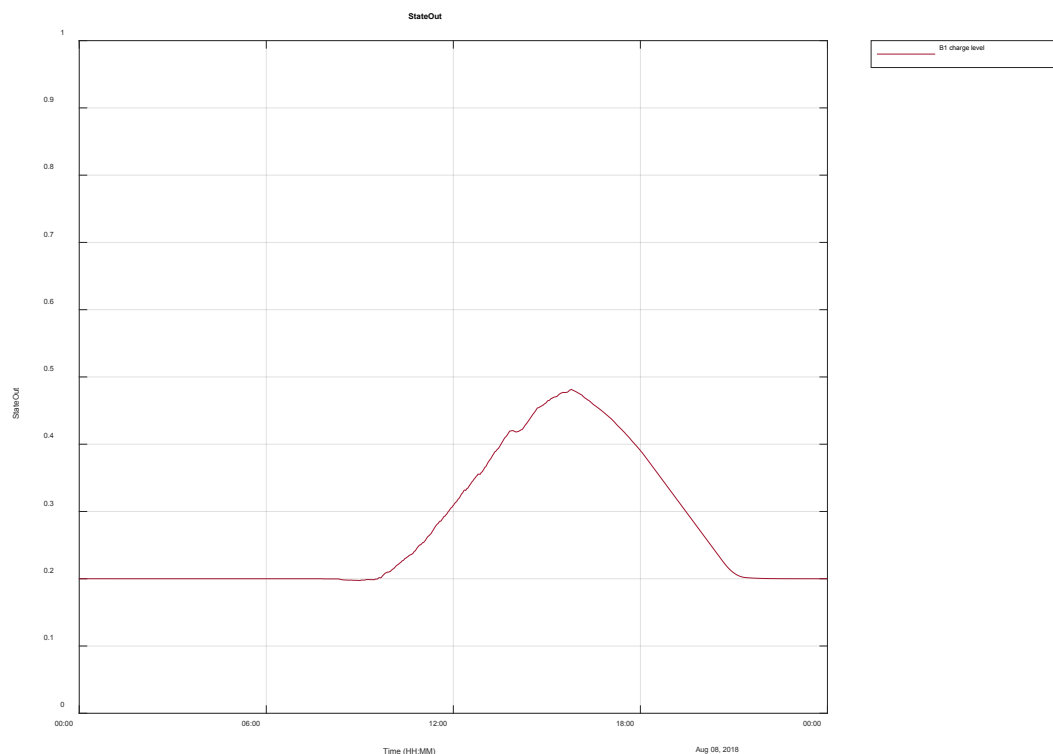
**Figure 3-54 Simulated generation output for weekday when 8 MW / 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV.**



**Figure 3-55 Simulated frequency for weekend when 8 MW / 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV.**



**Figure 3-56 Simulated battery charge level for weekday 8 MW / 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV.**

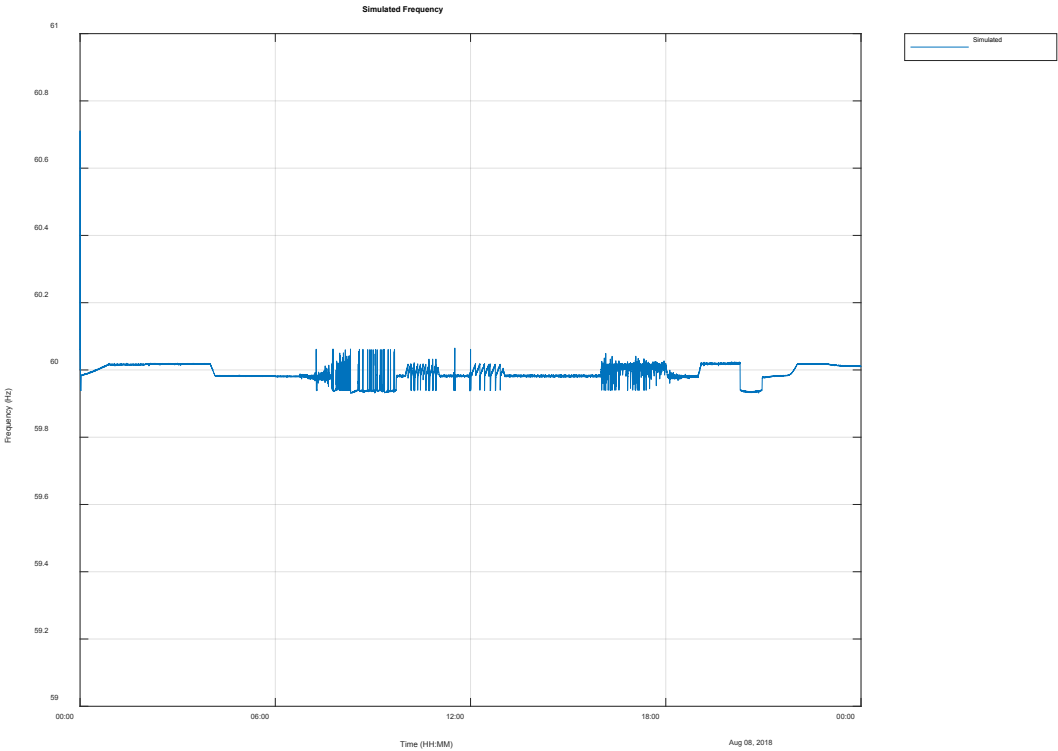


**Case 18: Weekday (8 August 2018) – 12 MW of PV and 8 MW / 8 MWh battery on AGC and all diesel off**

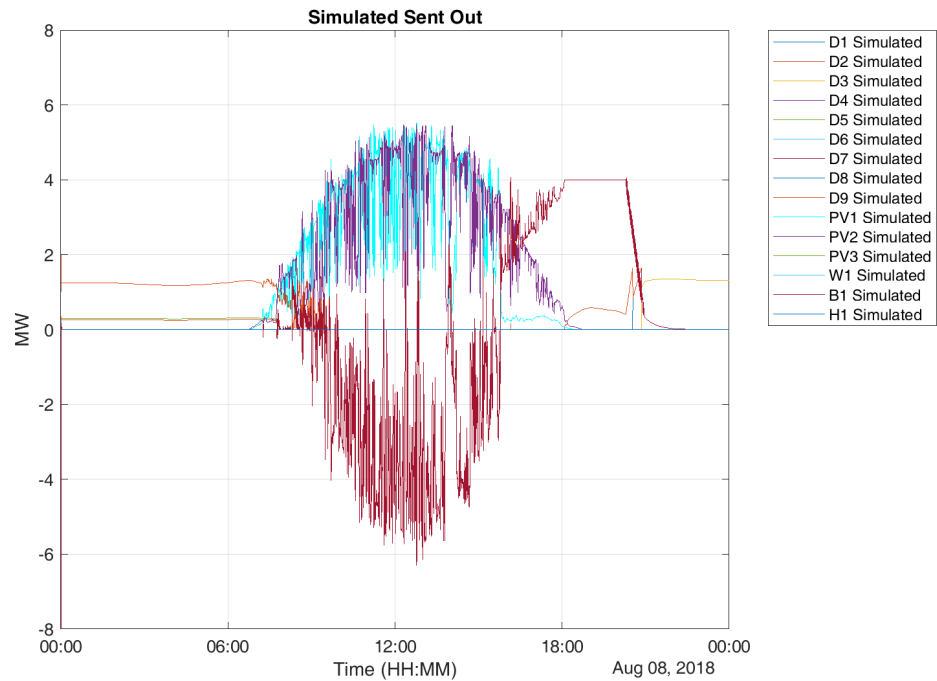
This case is a repeat of Case 17 but now the last diesel unit is allowed to go off line. The simulated frequency is within acceptable limits even when the last unit is off, as shown in Figure 3-57. The inverter size is adequate again as for previous case, as shown in Figure 3-58. The battery only charges to 45% all diesel units off until 18:00.

The nett saving with all units off is slightly increased to \$ 4,012 compared to case 17 of \$3,957.

**Figure 3-57 Simulated frequency for weekday when 8 MW / 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV. All diesel units allowed to go off.**



**Figure 3-58 Simulated generation output for weekday when 8 MW / 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV. All diesel units allowed to go off.**

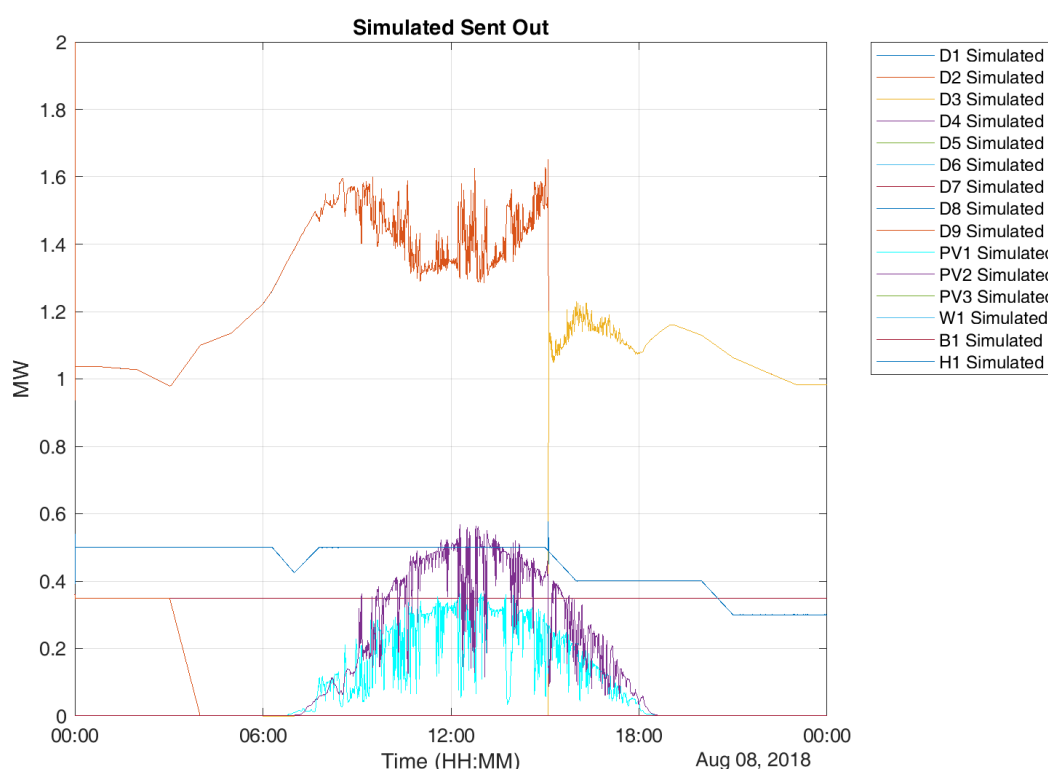


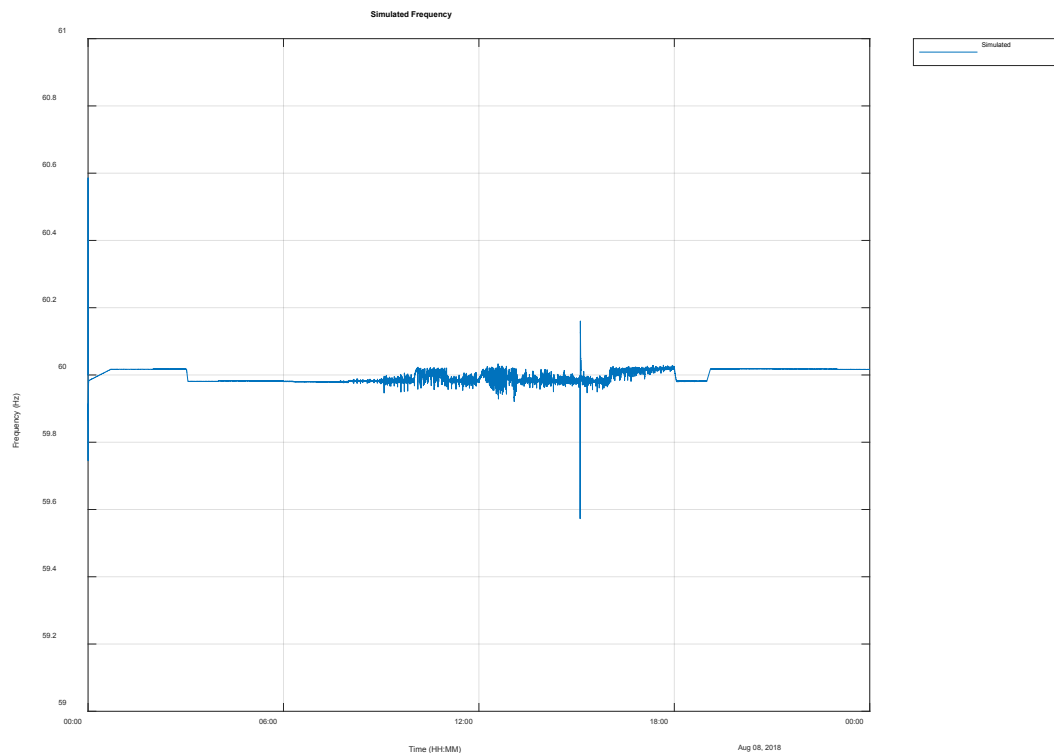
### 3.3.4 Base Case 4 & Simulation cases 19 – 24 (8 August 2018) with PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017 and hydro units on

Base Case 2: Weekday (8 August 2018) - Simulation of original day with PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017 and with hydro data from 8 August 2018.

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data. Figure 3-59 shows the simulation of generation unit outputs for Wednesday 8 August 2018, with PV1 of 0.4 MW from 14 March 17 and PV2 of 0.6 MW from 15 March 2017. For this base case and simulations the hydro generation is online, off AGC as it is not dispatchable as a run of river and output is as recorded on 8 August 2018. 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 3-60, is more or less what can be expected with second by second changes in demand.

**Figure 3-59 Simulated generation on weekday with current installed PV**



**Figure 3-60 Simulated frequency on weekday with current installed PV**

**Cases 19- 24: Weekday – Repeat of cases 13-18 with PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017 and hydro units on.**

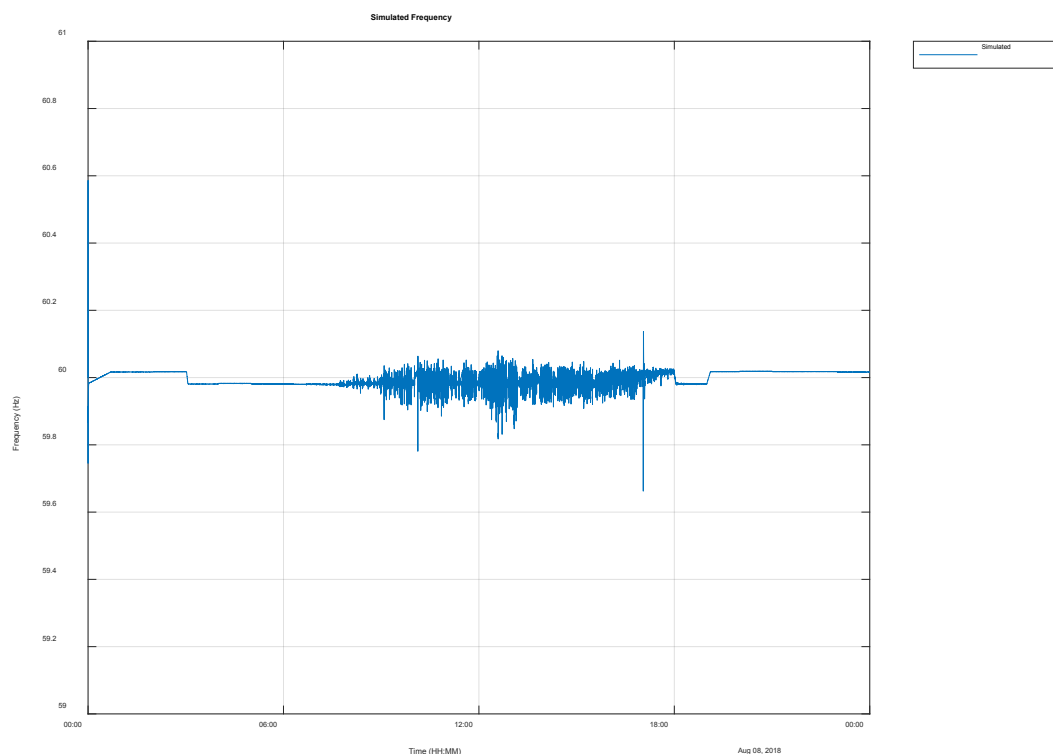
Cases 19 - 24 is the repeat of the simulations for a typical weekday but with hydro units on as recorded on 8 August 2018 and PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017. The simulated frequency is within an acceptable range for case 19 with 3 MW total PV simulated and no batteries, as shown in Figure 3-61 but the simulated frequency control is worse with the more volatile PV variations. Case 21 with 6 MW of simulated PV with a 2 MW / 2 MWh 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 3-62. Case 22 with 9 MW of simulated PV with a 4 MW / 4 MWh battery on AGC also results in an acceptable frequency control but with no excursions which suggest a inverter size is good, as shown in Figure 3-63. Case 24 with the 12 MW of PV and 8 MW / 8 MWh battery on AGC has the battery charging to full output around 18:00 and battery discharges unit 02:00 am the next day. All diesel units are off from 10:00 am to 02:00 am the next day.

The fuel savings for the same scenario for the weekend cases is very similar except the PV production for the cases 13 -18 was slightly higher than for cases 19 - 24 so daily fuel and net savings are also higher.

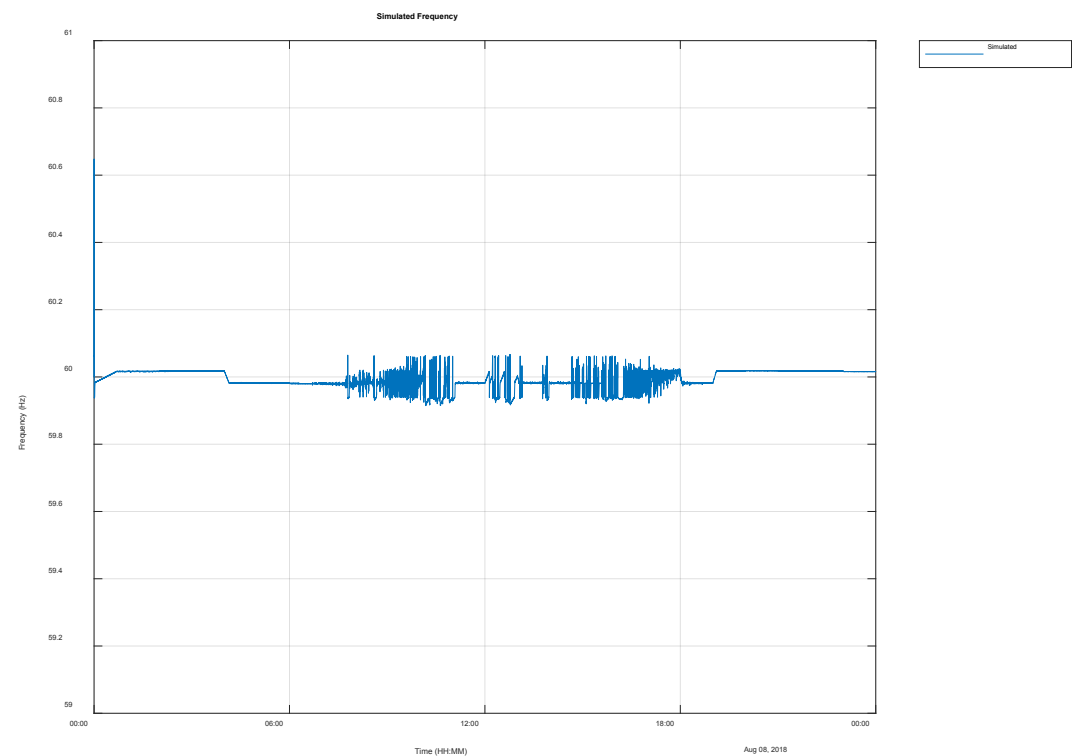


**Table 3-6 Comparison of daily fuel saving and net savings for a weekday with different PV input data**

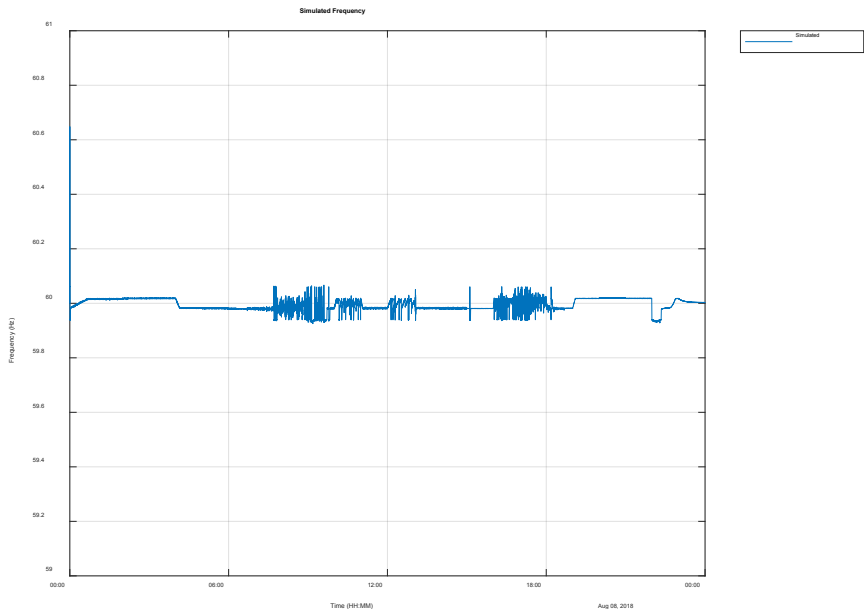
Simulation description	Case 13 - 18 daily diesel fuel savings	Case 19 - 24 daily diesel fuel savings	Case 13 - 18 daily net savings	Case 19 - 24 daily net savings
3 MW PV and no battery	2,109	2,182	1,137	1,135
3 MW PV and 1 MW / 1 MWh battery on gov	2,117	2,183	857	811
6 MW PV and 2 MW / 2 MWh battery on gov	5,027	5,604	2,021	2,376
9 MW PV and 4 MW / 4 MWh battery on AGC	8,375	9,051	3,336	3,678
12 MW PV and 8 MW / 8 MWh battery on AGC	11,604	12,511	3,957	4,418
12 MW PV and 8 MW / 8 MWh battery on AGC and all diesel allowed to go off	11,660	12,657	4,012	4,564

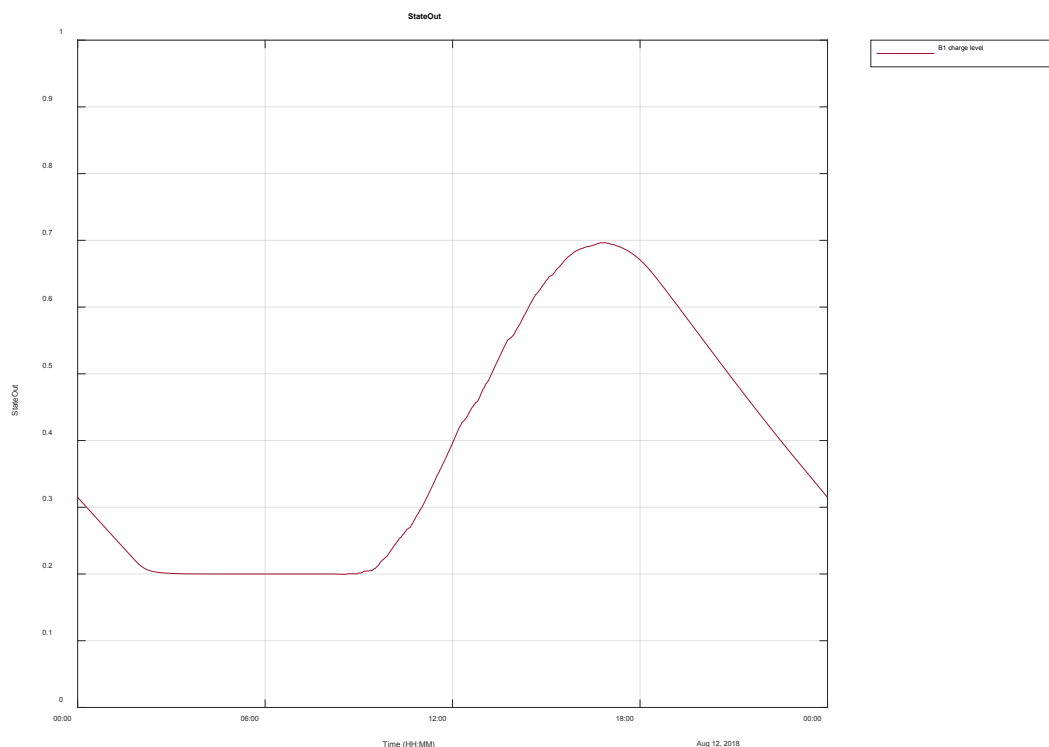
**Figure 3-61 Case 19 - Simulated frequency on weekday with 3 MW PV**

**Figure 3-62 Case 21 - Simulated frequency on weekday with 6 MW PV and 2 MW / 2 MWh battery on primary frequency control**



**Figure 3-63 Case 22 - Simulated frequency on weekday with 9 MW PV and 4 MW/ 4 MWh battery on AGC and primary frequency control.**



**Figure 3-64 Case 24 - Simulated charge level on weekday with 12 MW of PV and 8 MW / 8 MWh battery on AGC and all diesel units off.**

### 3.4 Financial Assessment of incorporating Storage

The simulations economic results are shown in Table 3-7. 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 3-7 Summary of economic results of simulations**

No	Sim demand 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	12 Aug 2018	1	18,938	100%	81.8	4.9	4.9	0.0	0.0%	off
1	12 Aug 2018	3	16,804	89%	72.3	14.4	14.59	0.2	1.6%	off
2	12 Aug 2018	3	16,805	89%	72.3	14.3	14.59	0.2	1.7%	1 MW / 1 MWh on Gov
3	12 Aug 2018	6	13,799	73%	57.7	28.9	29.17	0.3	1.1%	2 MW / 2 MWh on Gov & AGC
4	12 Aug 2018	9	10,918	58%	44.8	41.9	43.76	1.9	4.3%	4 MW / 4 MWh on Gov & AGC
5	12 Aug 2018	12	7,368	39%	31.0	57.73	58.34	0.6	1.0%	8 MW / 8 MWh on Gov & AGC
6	12 Aug 2018	12	7,295	39%	29.5	57.73	58.34	0.6	1.0%	8 MW / 8 MWh on Gov & AGC – diesel off
Base 2	12 Aug 2018	1	16,464	100%	70.8	5.1	5.1	0.0	0.0%	off
7	12 Aug 2018	3	14,341	87%	60.0	14.2	15.37	1.2	7.9%	off
8	12 Aug 2018	3	14,337	87%	62.0	14.1	15.37	1.2	8.0%	1 MW / 1 MWh on Gov
9	12 Aug 2018	6	11,694	71%	48.3	27.9	30.74	2.8	9.3%	2 MW / 2 MWh on Gov & AGC
10	12 Aug 2018	9	9,004	55%	36.4	40.1	46.11	6.0	13.0%	4 MW / 4 MWh on Gov & AGC
11	12 Aug 2018	12	3,986	24%	17.2	62.5	61.48	-1.0	-1.6%	8 MW / 8 MWh on Gov & AGC
12	12 Aug 2018	12	3,899	24%	17.3	62.5	61.48	-1.0	-1.6%	8 MW / 8 MWh on Gov & AGC – diesel off
Base 3	12 Aug 2018	1	21,542	100%	93.0	4.9	4.86	0.0	0.0%	off
13	12 Aug 2018	3	19,432	90%	83.4	14.4	14.59	0.2	1.1%	off
14	12 Aug 2018	3	19,425	90%	83.4	14.4	14.59	0.2	1.1%	1 MW / 1 MWh on Gov
15	12 Aug 2018	6	16,515	77%	69.5	28.3	29.17	0.9	2.9%	2 MW / 2 MWh on Gov
16	12 Aug 2018	9	13,166	61%	54.5	43.3	43.76	0.5	1.1%	4 MW / 4 MWh on Gov & AGC

17	12 Aug 2018	12	9,937	46%	40.1	57.7	58.34	0.6	1.1%	8 MW / 8 MWh on Gov & AGC
18	12 Aug 2018	12	9,882	46%	40.1	57.7	58.34	0.6	1.1%	8 MW / 8 MWh on Gov & AGC – diesel off
Base 4	12 Aug 2018	1	19,045	100%	82.2	5.2	5.2	0.0	0.0%	off
19	12 Aug 2018	3	16,864	89%	71.8	15.6	15.70	0.1	0.6%	off
20	12 Aug 2018	3	16,863	89%	71.8	15.6	15.70	0.1	0.6%	1 MW / 1 MWh on Gov
21	12 Aug 2018	6	13,441	71%	56.2	31.2	31.40	0.2	0.6%	2 MW / 2 MWh on Gov & AGC
22	12 Aug 2018	9	9,994	52%	40.6	46.8	47.10	0.3	0.6%	4 MW / 4 MWh on Gov & AGC
23	12 Aug 2018	12	6,535	34%	28.5	62.5	62.80	0.3	0.5%	8 MW / 8 MWh on Gov & AGC
24	12 Aug 2018	12	6,388	34%	26.4	62.5	62.80	0.3	0.5%	8 MW / 8 MWh on Gov & AGC – diesel off

The simulations show that it is possible to increase the renewable energy penetration up to 3 MW with no battery support, but diesel units must be on AGC, a 1 MW/1 MWh battery is recommended. A 2 MW / 2 MWh battery can sustain 6 MW of PV without a negative impact on frequency control and similarly for a 4 MW/ 4 MWh battery can sustain 9 MW of PV. An 8 MW / 8 MWh battery size is required for a PV of 12 MW to utilise the excess energy from the PV and maintain adequate frequency control.

Table 3-8 shows a summary of the simulation 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. Inverter costs are estimated at US\$ 500 per kW and battery at US\$ 375 / kWh installed

The technical ability to take off all diesel units needs further analysis but saves more than US\$ 100 per day.

**Table 3-8 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	3	15,573	2,128	0.236	88%	66.1	14.3	15.0	0.7	4.7%	999		1,130
2 & 8	3	15,571	2,130	0.232	88%	67.1	14.2	15.0	0.7	4.8%	999		844
3 & 9	6	12,746	4,955	0.241	72%	53.0	28.4	30.0	1.6	5.2%	2,496	575	1,883
4 & 10	9	9,961	7,740	0.246	56%	40.6	41.0	44.9	3.9	8.7%	3,994	1,150	2,596
5 & 11	12	5,677	12,024	0.235	32%	24.1	60.1	59.9	-0.2	-0.3%	5,492	2,299	4,232
6 & 12	12	5,597	12,104	0.236	31%	23.4	60.1	59.9	-0.2	-0.3%	5,492	2,299	4,313
13 & 19	3	18,148	2,145	0.234	89%	77.6	15.0	15.1	0.1	0.8%	1,010		1,136
14 & 20	3	18,144	2,150	0.234	89%	77.6	15.0	15.1	0.1	0.8%	1,028		834
15 & 21	6	14,978	5,316	0.239	74%	62.8	29.8	30.3	0.5	1.7%	2,542	575	2,198
16 & 22	9	11,580	8,713	0.244	57%	47.5	45.1	45.4	0.4	0.8%	4,057	1,150	3,507
17 & 23	12	8,236	12,057	0.239	40%	34.3	60.1	60.6	0.5	0.8%	5,571	2,299	4,187
18 & 24	12	8,135	12,158	0.244	40%	33.3	60.1	60.6	0.5	0.8%	5,571	2,299	4,288

The simulations show that with 3 MW of PV power plants and no batteries will save US\$ 1,130 for a weekend day and a simulated saving of US\$1,136 for the week day. 9 MW of PV power plants and keeping 4 MW / 4 MWh battery on primary frequency control and AGC gives an additional cost of US\$2,596 for a weekend day and US\$3,507 for the week day. 12 MW of PV power plants and keeping 8 MW / 8 MWh battery on primary frequency control and AGC gives a saving of US\$ 4,232 for a weekend day and US\$4,187 for the week day.

Switching the last unit off during the day saving on fuel running last unit at minimum generation will realise more savings US\$ 100 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 3-9.

The case of 3 MW of PV and no battery has an estimated saving of US\$ 410,000 per annum. The 6 case with 2 MW / 2 MWh battery has an annual estimated saving of US\$ 760,000. The case where 16 MW of PV is installed with 8 MW / 8 MWh battery the annual estimated savings increase around US\$ 1.5 million per annum.

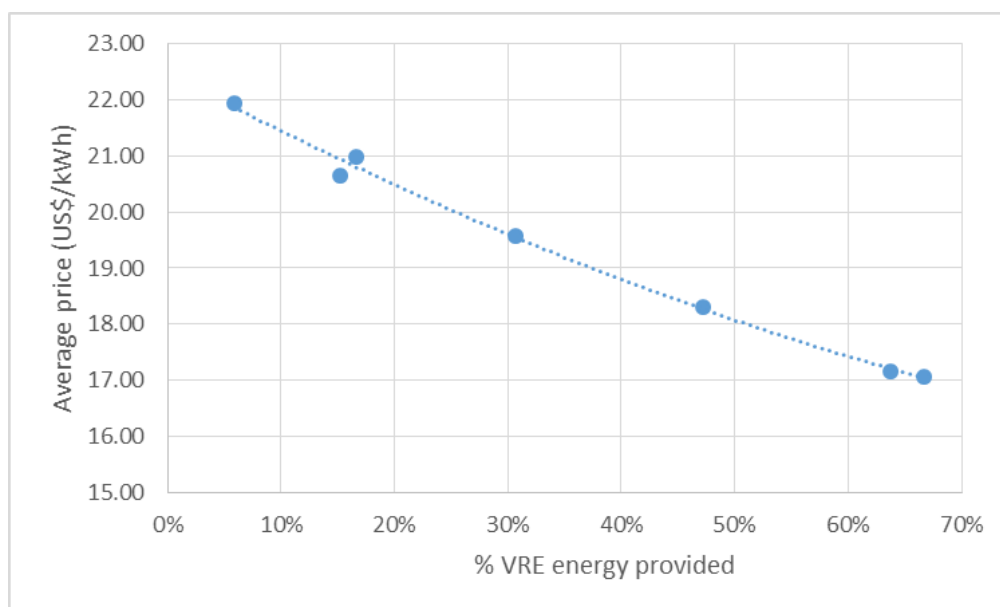
**Table 3-9 Estimated annualised solar and battery costs and fuel savings**

Description	PV Installed (MW)	% peak	Estimated diesel savings (pa)	Estimated additional PV costs (pa)	Estimated additional battery costs (pa)	Estimated nett saving (pa)
3 MW PV and no battery	3	60%	779,140	366,317	0	412,823
3 MW PV and 1 MW / 1 MWh battery on gov	3	60%	780,380	371,140	104,623	304,617
6 MW PV and 2 MW / 2 MWh battery on gov	6	120%	1,897,329	920,616	209,247	767,467
9 MW PV and 4 MW / 4 MWh battery on AGC	9	180%	3,070,354	1,470,091	418,493	1,181,769
12 MW PV and 8 MW / 8 MWh battery on AGC	12	240%	4,385,365	2,019,567	836,986	1,528,812
12 MW PV and 8 MW / 8 MWh battery on AGC and all diesel allowed to go off	12	240%	4,419,991	2,019,567	836,986	1,563,438

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\$ 7,117,181 at an average 23.2 USc/ kWh. The total variable costs (including additional VRE and battery costs) decreases incrementally as more PV and suggested batteries are added, giving an estimated 11% with 6 MW of PV and 22% saving with 12 MW of PV.

**Table 3-10 Estimated annualised solar and battery costs and fuel savings**

Description	PV Installed (MW)	% peak	Total 'variable' costs	Average 'variable' costs US\$/kWh	% decrease in total 'variable' costs from base cases
3 MW PV and no battery	3	60%	6,704,358	20.656	6%
3 MW PV and 1 MW / 1 MWh battery on gov	3	60%	6,812,564	20.992	4%
6 MW PV and 2 MW / 2 MWh battery on gov	6	120%	6,349,714	19.563	11%
9 MW PV and 4 MW / 4 MWh battery on AGC	9	180%	5,935,411	18.300	17%
12 MW PV and 8 MW / 8 MWh battery on AGC	12	240%	5,588,369	17.167	22%
12 MW PV and 8 MW / 8 MWh battery on AGC and all diesel allowed to go off	12	240%	5,553,743	17.058	22%

**Figure 3-65 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 3-11 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 3-11: Average Supply Costs (US Cents/kWh)<sup>15</sup>**

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

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 3-12: Average Supply costs versus Tariffs for 2017 in US c/kwh<sup>16</sup>**

		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 Pohnpei option with 12MW PV combined with 8 MW/8MWH battery on AGC substituting all of the diesel generation would have the biggest impact on the variable costs. The total decrease in

<sup>15</sup> PPA Benchmarking Report Fiscal year 2017 (published September 2018)

<sup>16</sup> PPA Benchmarking Report Fiscal year 2017 (published September 2018)

total variable costs from the base case scenario would be 22%. Variable costs meaning fuel costs plus annualised costs of PV and battery. This is used to estimate the incremental system cost in each case.

**Table 3-13: Pohnpei - Estimated annual total variable costs and percentage savings**

Description	PV Installed (MW)	% peak	Total 'variable' costs	Average 'variable' costs USc/kWh	% decrease in total 'variable' costs from base cases
3 MW PV and no battery	3	60%	6,704,358	20.656	6%
3 MW PV and 1 MW / 1 MWh battery on gov	3	60%	6,812,564	20.992	4%
6 MW PV and 2 MW / 2 MWh battery on gov	6	120%	6,349,714	19.563	11%
9 MW PV and 4 MW / 4 MWh battery on AGC	9	180%	5,935,411	18.3	17%
12 MW PV and 8 MW / 8 MWh battery on AGC	12	240%	5,588,369	17.167	22%
12 MW PV and 8 MW / 8 MWh battery on AGC and all diesel allowed to go off	12	240%	5,553,743	17.058	22%

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 3-14: Estimated Impact on Supply Costs and Tariff (in 2017 annualised figures)**

Description	Total 'variable' costs	Average 'variable' costs USc/kWh	% decrease in total 'variable' costs from base cases	2017 Supply Cost USc/kWh	Impact on Supply Cost	2017 Tariff USc/kWh	Impact on Tariff
3 MW PV and no battery	6,704,358	20.656	6%	28.75	27.51	49.05	47.81
3 MW PV and 1 MW / 1 MWh battery on gov	6,812,564	20.992	4%	28.75	27.91	49.05	48.21
6 MW PV and 2 MW / 2 MWh battery on gov	6,349,714	19.563	11%	28.75	26.60	49.05	46.90
9 MW PV and 4 MW / 4 MWh battery on AGC	5,935,411	18.3	17%	28.75	25.64	49.05	45.94
12 MW PV and 8 MW / 8 MWh battery on AGC	5,588,369	17.167	22%	28.75	24.97	49.05	45.27
12 MW PV and 8 MW / 8 MWh battery on AGC and all diesel allowed to go off	5,553,743	17.058	22%	28.75	25.00	49.05	45.30

Even though the average supply costs of US cents 40.75/kwh for the years 2012-2017 are already well below the actual tariff of US cents 49.05/kwh, the best-case scenario as described above would have a net impact on the tariff of more than US cents 4/kwh (from US cents 49.05/kwh to US cents 45.27/kwh).

### 3.6 Recommendations for application of storage

The studies show that 3 MW of PV can be installed without the need for batteries primary frequency control support. More than 3 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 reaches 3 MW. The simulations show that the 2 MW / 2 MWh battery is probably sufficient for 6 MW of installed PV but this strategy requires that all major PV plants can reduce their output from a centralised control system (AGC).

The annual savings increase when 9 MW with a 4 MW/4 MWh battery is installed to over US\$ 1 million.

The simulations show that installing 12 MW of PV with 8 MW / 8 MWh of battery with the current demand will decrease the variable component of the tariff by 22% from 23 to 17 USc / kWh. This is a major

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decrease on the overall tariff based on 0.82 US\$ / litre (3.14 US\$ per gallon). These studies would need to be repeated on the new demand, PV costs and battery costs in a few years' time to determine the next optimal step.

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

Based on best practices adopted in other countries, a grid code has been developed for the Pohnpei Utilities Corporation. This code 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.

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

### 5.1 Introduction

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

The description of SCADA systems is provided in Appendix 3. This includes an explanation of SCADA system's basic activity, details of additional applications of SCADA, comparison of Energy Management System (EMS) and Distribution Management System (DMS).

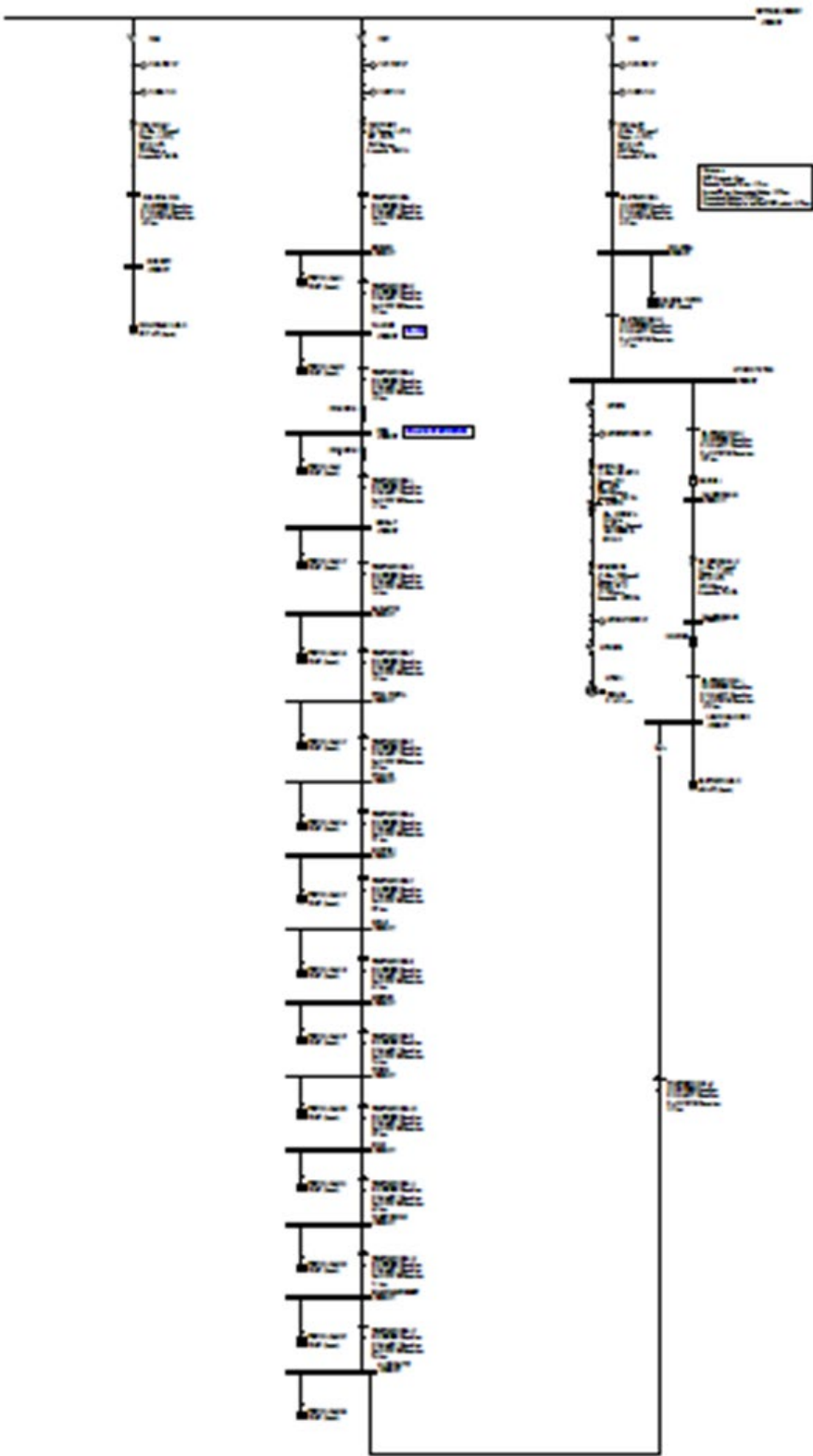
### 5.2 Network and available Operation Systems

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

Concept	Value	Unit
Peak Load	1.000	kw
Total Energy generated per year	1.535,6	Mwh
PV Energy generated per year	1.183,6	Mwh
Hydro Energy generated per year (1)	352,0	Mwh
Available Generators Conventional		
Generators Renewable		
Conventional Installed power		Mw
Renewable Installed power		Mw
Available SCADA for Generation Control		
Controls some breakers		
Operated Radial		
Number of feeders	3	

(1) Some unavailability's during the year

POHNPEI single line diagram:



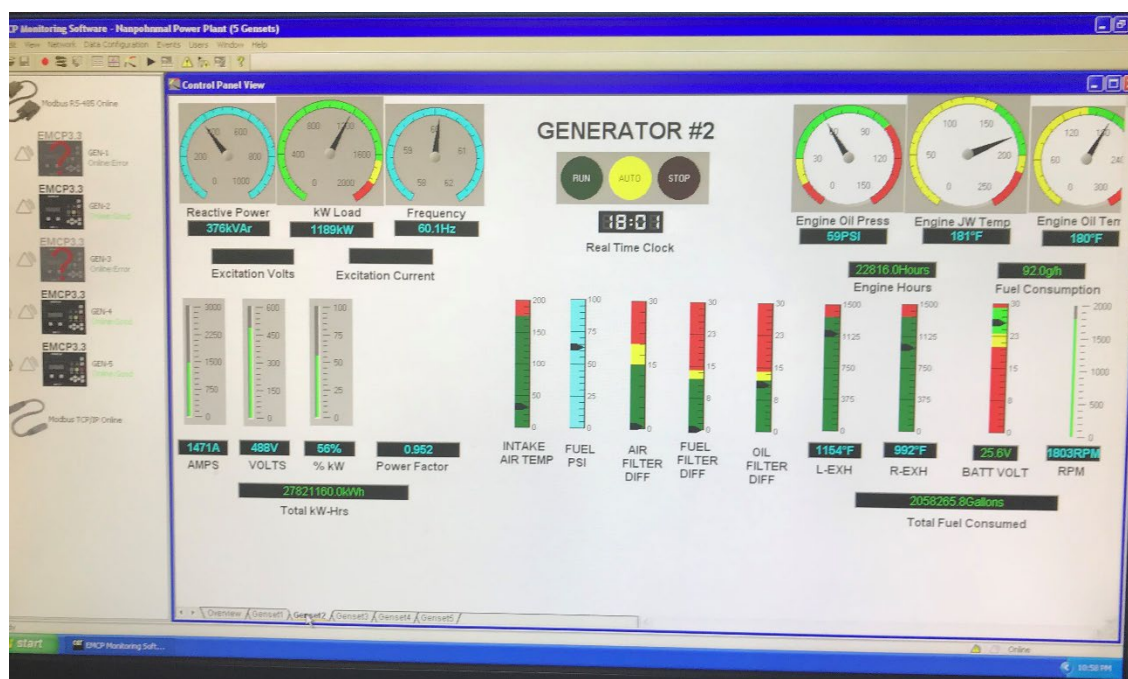
An existing SCADA System controls the frequency and co-ordinates Units in Diesel groups.

Functionality is limited to:

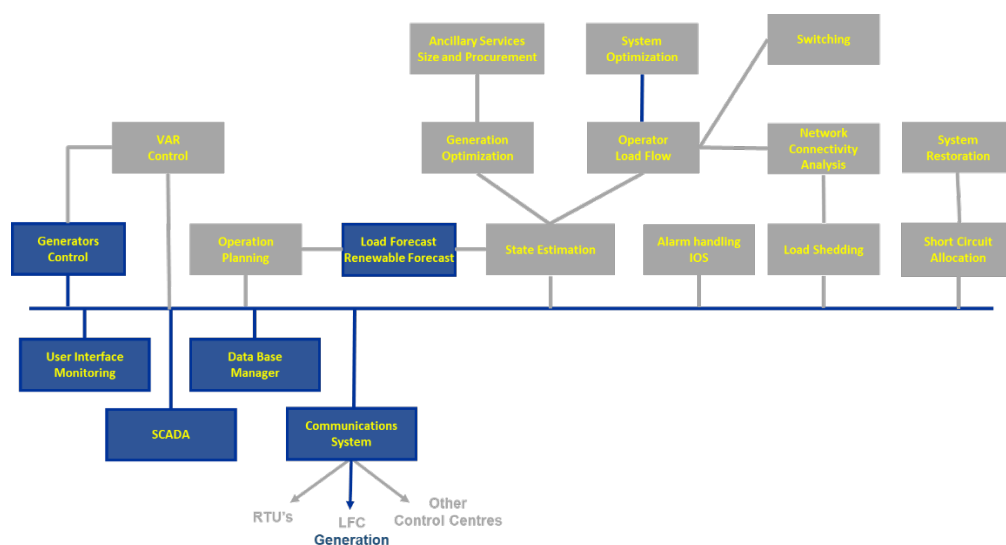
- Full control of the Caterpillar generation units, including some optimization of the generation assigned to each unit.
- Control of the Vital generation units by IPP. This not linked to the control system above.
- Basic control (switching) of some feeder heads. Plan to expand it to some other substations
- No additional functionalities available in top of the SCADA

In addition there is a two data recording systems one for the Caterpillar Diesel units as shown in Figure 5-1 and an information system at Pohnpei Hydro Power Station.

**Figure 5-1 Caterpillar information system display**



The figure shows the actual SCADA configuration:



Battery and 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.

## 5.3 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 performing 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.

### 5.3.1 Priorities

The priority for improvements:

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

### 5.3.2 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.

#### 5.3.2.1 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.

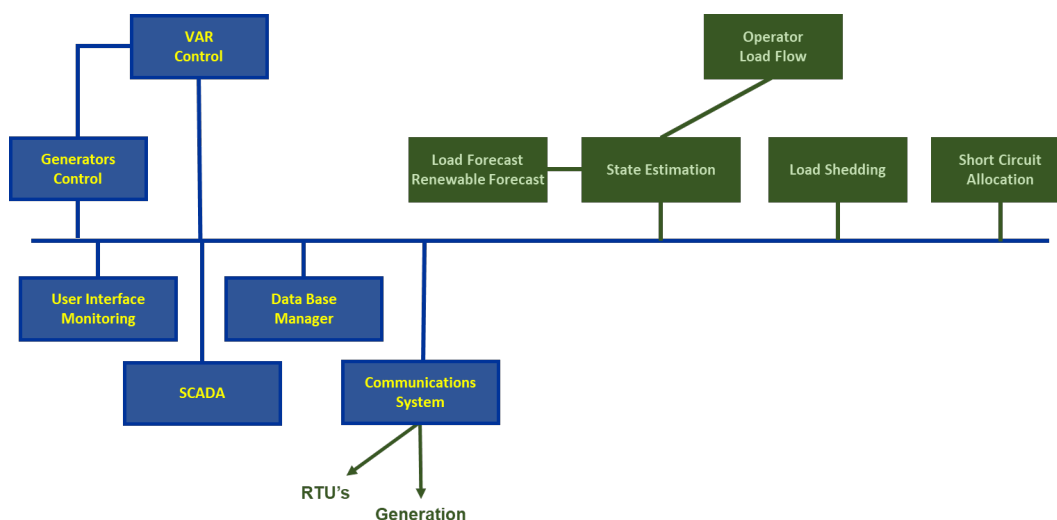


3. **State Estimation.** Contrary to the EMS, where state estimation calculates the Voltage and Flows and corrects missing or erroneous loads and generation, the DMS calculates the load values in intermediate not measured points.
4. **Operator Load Flow.** Calculates intermediate voltage and flows between 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.

6. **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:



### 5.3.2.2 Economic Optimization and technical loss reduction

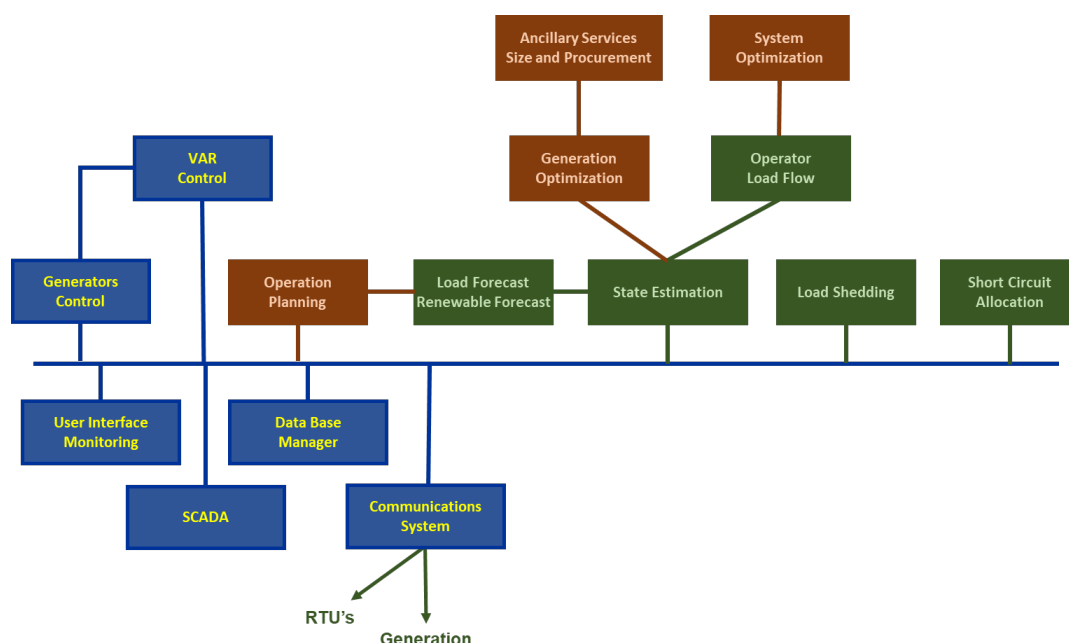
1. **System Optimization.** The technical losses are a function of the resistance and the quadratic of the current circulated between two points. Resistance is a value that depends on the infrastructure and characteristics of the lines or cables. But the Current depends on the network topology. A Minimum 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 POHNPEI system is not inside the definition of "transmission interconnected systems" but is also true that to operate a system like POHNPEI requires consideration of the need for Ancillary Services
4. 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.
5. 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):



### 5.3.2.3 Functionality not recommended

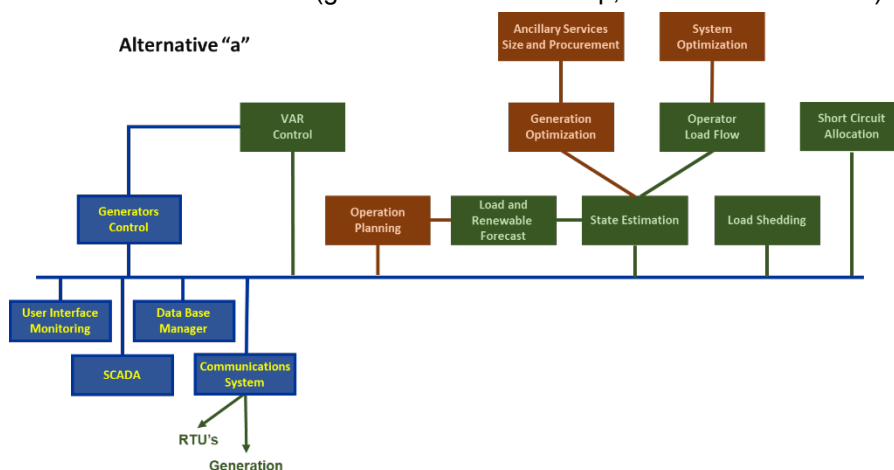
Some functionality is more oriented to much larger systems, where an operator cannot have a detailed knowledge of the full grid. This is not the case observed in the POHNPEI electricity system. These functions are not recommended.

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.

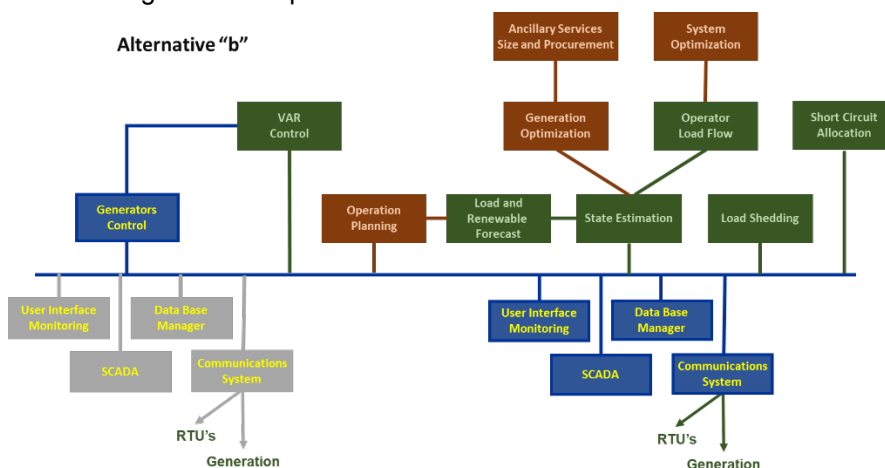
## 5.4 Architecture Potential alternatives

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:

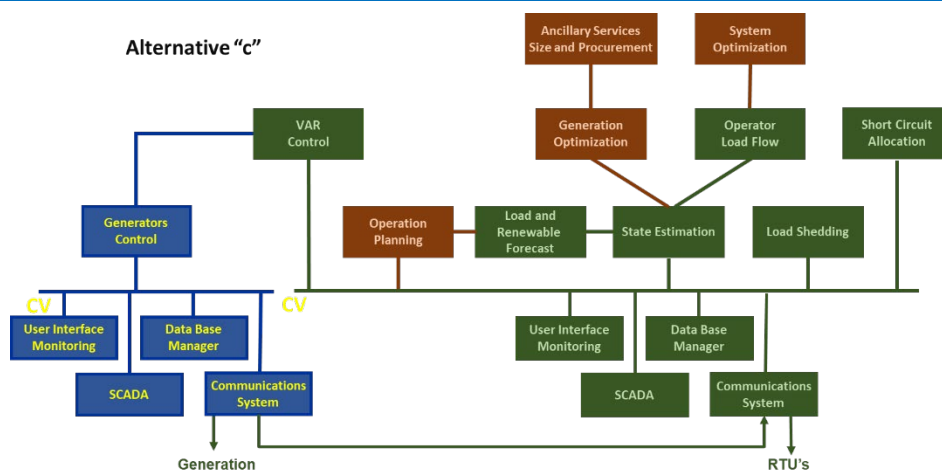
- Use the actual SCADA system that is available in the POHNPEI system for diesel generation control (blue blocks in the following figures) and expand its functionality with the one required for distribution network control (green blocks at first step, and brown in second).



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



- 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 taken 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 generator’s 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 for the first phase 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.

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

## 5.5 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

### 5.5.1 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 POHNPEI, to start with, the number of RTU's shall be between 3 and 4.

### 5.5.2 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.

### 5.5.3 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 communications should be protected to avoid intrusions, improving the cyber security.

### 5.5.4 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

## 5.6 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.

### 5.6.1 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.

### 5.6.2 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.

### 5.6.3 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, can 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.

## 5.7 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.



### 5.7.1 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 3 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.

### 5.7.2 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 on 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 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.

### 5.7.3 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 public 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:

#### 5.7.3.1 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.

#### 5.7.3.2 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 may suffer economic losses and streetlighting outages can impact public safety.

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.

## 5.8 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.

### 5.8.1 Recommendation for staged implementation and roadmap: Pohnpei

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, large PV plants and some reclosers on the 13.8kV backbone with the ability to perform remote switching of the network	Extend the SCADA to include all PV plants and additional reclosers on the 13.8kV backbone  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 large PV plant with the following capabilities:

- Monitoring of the following:
  - o Switch positions (status of breakers and isolators)
  - o Basic power flow measurands (e.g. amps, MW, MVAR and voltages) at key network positions
  - o Transformer tap positions
  - o Alarm signals limited to common / grouped alarms
- Provide remote control capability of:
  - o Open / close of switches (breakers and isolators)
  - o Set generator setpoints and limits
  - o 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 additional nodes on the 13.8kV backbone 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.

Note: All 13.8kV nodes may not be covered with visibility at stage 2 depending on the final budget and cost to implement telemetry for each recloser.

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**

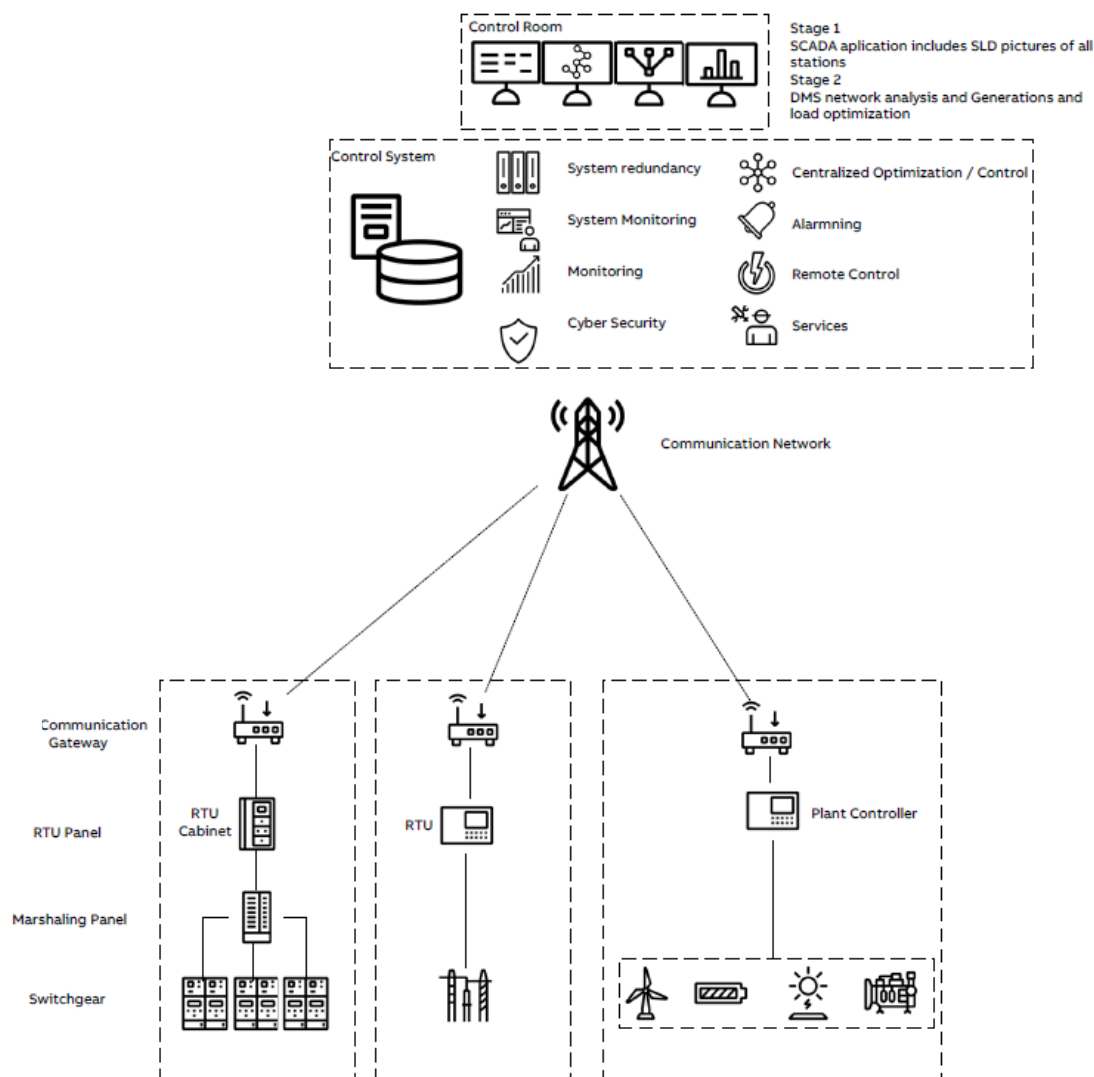
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In future, the following DMS modules can be considered as the grid evolves:

- 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

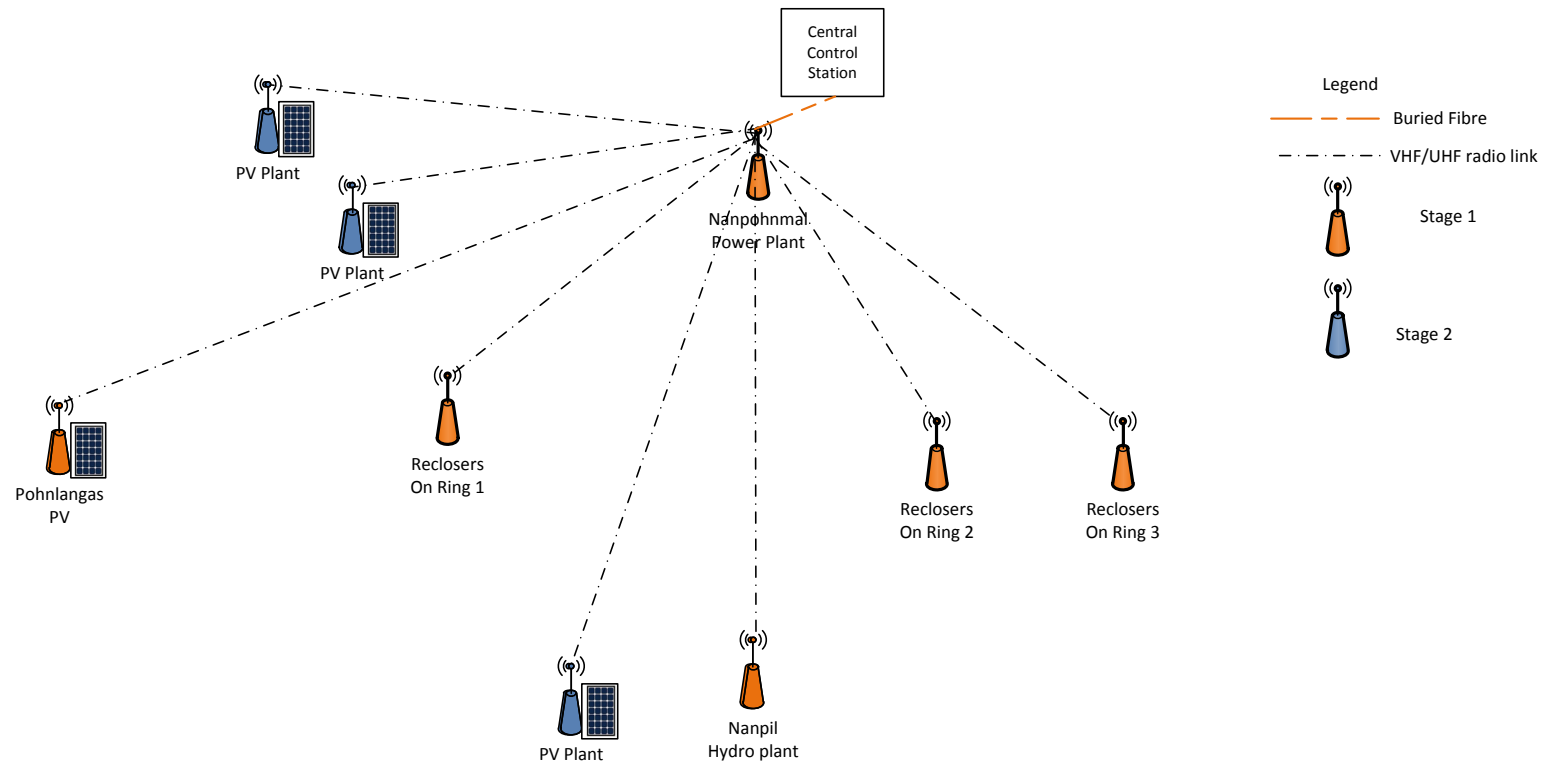
The conceptual design of the SCADA Control System is described in Figure 5-2.

Figure 5-2: Conceptual design of the SCADA Control System



The conceptual design solution of the communication network is described in **Figure 5-3**.

**Figure 5-3: Concept communication network diagram for Pohnpei 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. Line-of-sight paths and signal propagation budget calculations need to be confirmed in the next project stage.
- 3) 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 Pohnpei network

## 5.8.2 Cost Estimate

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

**Table 5-1 Estimated cost for stage 1 and 2 for Pohnpei**

	Stage 1				Stage 2				Notes
	Qty	Unit	Unit cost	Total cost	Qty	Unit	Unit cost	Total cost	
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		\$ 20,000	\$ 20,000	1 lot		\$ 30,000	\$ 30,000	
Design and engineering	1 lot		\$ 40,000	\$ 40,000	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)	20 each		\$ 5,000	\$ 100,000	15 each		\$ 5,000	\$ 75,000	Provisional qty for telemetry of switches on back
- RTUs (PV sites)	1 each		\$ 5,000	\$ 5,000	3 each		\$ 5,000	\$ 15,000	Telemetry of PV sites
- Transducers	10 each		\$ 2,000	\$ 20,000	10 each		\$ 2,000	\$ 20,000	Provisional estimate subject to site audit
- Communication equipment: Central Station	1 each		\$ 20,000	\$ 20,000			\$ -		
- Communication equipment: Stations	21 each		\$ 5,000	\$ 105,000	18 each		\$ 5,000	\$ 90,000	
- Auxiliary DC system	21 each		\$ 2,000	\$ 42,000	18 each		\$ 2,000	\$ 36,000	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	21 each		\$ 5,000	\$ 105,000	18 each		\$ 5,000	\$ 90,000	Provisional estimate subject to site audit
				\$ -				\$ -	
Travel and accommodation	1 lot		5.0%	\$ 29,200	1 lot		5.0%	\$ 21,800	
Project overheads	1 lot		5.0%	\$ 29,200	1 lot		5.0%	\$ 21,800	
Contingency	1 lot		15.0%	\$ 87,600	1 lot		15.0%	\$ 65,400	
								\$ -	
				\$ 730,000				\$ 545,000	

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

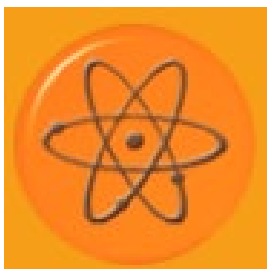
Appendix 1: Grid Connection Code

Appendix 2: Description of GDAT model

Appendix 3: Description of SCADA and EMS

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## Appendix 1: Grid Connection Code



Pohnpei Utilities Corporation

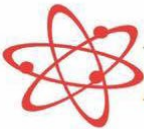
Grid Connection Code for Renewable Power  
Plants and Battery Storage Plants

Version 0.2

May 2019

Enquiries: The secretariat  
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## Version control

 <b>POHNPEI UTILITIES CORPORATION</b>		
Document #	Title: <b>Grid Connection Code for Renewable Power Plants including Battery Storage Plants</b>	Print Date: <b>[Date]</b>
Revision # <b>0.2 Draft</b>	Prepared By: <b>Dr Graeme Chown and Rahul Desai – Ricardo Energy &amp; Environment</b>	Date Prepared: <b>May 2019</b>
Effective Date: <b>[Date]</b>	Reviewed By: <b>Trevor Fry – Ricardo Energy &amp; Environment</b>	Date Reviewed: <b>May 2019</b>
Standard: <b>Code</b>	Approved By: <b>[Approver's Name]</b>	Date Approved: <b>[Date]</b>

## 1 Objectives

- (1) The primary objective of this grid connection code is to specify minimum technical and design grid connection requirements for *Renewable Power Plants* connected to or seeking connection to the Pohnpei Utilities Corporation's network.
- (2) This document shall be used together with other applicable requirements for connecting to the network.
- (3) This code was based on EU Commission Regulation 2016/1388, Kingdom of Swaziland Grid Code for Renewable Power Plants Connected to the Electricity Transmission System or the Distribution System and IEEE 1547, and adapted for the Pohnpei network

## 2 Scope

- (1) The grid connection requirements in this code shall apply to all *Renewable Power Plants*, which shall for this code include *Battery Storage Plants*, connected or seeking connection to the Pohnpei Utilities Corporation's network.
- (2) This grid connection code shall, at the minimum, apply to the following technologies:
  - (a) *Photovoltaic*
  - (b) *Wind*
  - (c) *Battery Storage*
- (3) Unless otherwise stated, the requirements in this grid connection code shall apply equally to all *Renewable Power Plants*, *Storage Plants* and *Types*.
- (4) The *Renewable Power Plant* shall, for the duration of its generation licence issued by an appropriate authority (*Pohnpei Utilities Corporation* to advise who this is), comply with the provisions of this grid connection code and all other applicable codes, rules and regulations.
- (5) Where there has been a replacement of or a major modification to an existing *plant*, the *plant owners/operators* shall be required to demonstrate compliance with these requirements before being allowed to operate commercially.
- (6) Compliance with this grid connection code shall be applicable to the *Renewable Power Plants* depending on their rated power and, where indicated, the nominal voltage at the *point of connection to the grid*. Accordingly, *Renewable Power Plants* are grouped into the following three *Types*:
  - (a) Type A: 0 MVA – less than 0.2 MVA connected 400 V network
  - (b) Type B: 0.2 MVA – less than 1 MVA connected to the 11 kV network or 400 V network
  - (c) Type C: 1 MVA or higher and any plants connected to 22 kV network or higher

- (7) The requirements of this grid connection code are organized according to above-defined Types.
- (8) The *Pohnpei Utilities Corporation* shall supply the *Renewable Power Plants* owner with detail of their Network that is sufficient to allow an accurate analysis of the interaction between the plant and the Pohnpei Utilities Corporation's network, including information about other generation facilities.

### **3 Definitions and Abbreviations**

#### **Active Power Curtailment Set-point**

The limit set by the *Pohnpei Utilities Corporation* for the amount of active power that the *Renewable Power Plant* is permitted to generate. This instruction may be issued manually or automatically via a communication facility. The manner of applying the limitation shall be agreed between the parties.

#### **Available Active Power**

The amount of active power (MW), measured at the *point of connection to the grid*, that the *Renewable Power Plant* could produce based on plant availability as well as current renewable primary energy conditions (e.g. wind speed, solar radiation or charge available).

#### **Curtailed Active Power**

The amount of Active Power that the *Renewable Power Plant* is permitted to generate by the *Pohnpei Utilities Corporation* subject to network or system constraints.

#### **Pohnpei Utilities Corporation**

Means the Pohnpei Utilities Corporation a component unit of Pohnpei Government established by Act....

#### **Rated power**

The highest active power measured at the *point of connection*, which the *Renewable Power Plant* is designed to continuously supply.

#### **Rated wind speed**

The average wind speed at which a *Wind Power Plant* achieves its *rated power*. The average wind speed is calculated as the average value of wind speeds measured at hub height over a period of 10 minutes.

#### **Renewable Power Plant**

One or more *unit(s)* and associated equipment, with a stated *rated power*, which has been connected to the same *point of connection* and operating as a single power plant.

It is, therefore, the entire *Renewable Power Plant* that shall be designed to achieve requirements of this code at the *point of connection*. A *Renewable Power Plant* has only one *point of connection*.

In this *code*, the term *Renewable Power Plant* is used as the umbrella term for a *unit* or a system of generating *units* producing electricity based on a primary renewable energy source (e.g. wind, sun, water etc.) and *Battery Storage Plant*. A *Renewable Power Plant* can use different kinds of primary energy source. If a *Renewable Power Plant* consists of a homogeneous type of generating *units* it can be named as follows:

#### **PV Power Plant (PVPP)**

Single *Photovoltaic* panel or a group of several *Photovoltaic* panels with associated equipment operating as a power plant.

#### **Wind Power Plant (WPP)**

Single turbine or a group of several turbines driven by wind as fuel with associated equipment operating as a power plant. This is also referred to as a wind energy facility (WEF)

#### **Battery Storage Power Plant (BSPP)**

Single battery or a group of several batteries installed for system security through provision of frequency and voltage control services and or used for storage of electrical energy.

#### **Renewable Power Plant (RPP) Controller**

A set of control functions that make it possible to control the *Renewable Power Plant* at the *point of connection to the grid*. The set of control functions shall form a part of the *Renewable Power Plant*.

#### **RPP Generator**

Means a legal entity that is licensed to develop and operate a *Renewable Power Plant*.

#### **Voltage Ride Through (VRT) Capability**

The capability of the *Renewable Power Plant* to stay connected to the network and keep operating following voltage dips or surges caused by short-circuits or disturbances on any or all phases in the *Network*.

## **4 Tolerance of Frequency and Voltage Deviations**

- (1) The *Renewable Power Plant* shall be able to withstand frequency and voltage deviations at the point of connection to the grid under normal and abnormal operating conditions described in this grid connection code while reducing the active power as little as possible.
- (2) The *Renewable Power Plant* shall be able to support network frequency and voltage stability in line with the requirements of this grid connection code.

- (3) Normal operating conditions and abnormal operating conditions are described in section 4.1 and section 4.2, respectively.

#### 4.1 **Normal Operating Conditions**

- (1) Unless otherwise stated, requirements in this section shall apply to all Types of *Renewable Power Plants*.
- (2) All *Renewable Power Plants* shall be designed to be capable of operating within the voltage range of  $\pm 10\%$  around the nominal voltage at the point of connection to the grid. The actual operating voltage differs from location to location, and this shall be decided by the *Pohnpei Utilities Corporation* in consultation with the affected customers (including the *Renewable Power Plant*), and implemented by the *Renewable Power Plant* owner or operator.
- (3) The nominal frequency of the *Pohnpei Utilities Corporation's* network is 60 Hz and is normally controlled within the limits of 59.5 to 60.5 Hz.
- (4) All *Renewable Power Plants* facilities shall be capable of remaining connected to the network and operate within the frequency range of 57.0 to 62.0 Hz.
- (5) *Pohnpei Utilities Corporation* and the power-generating facility owner may agree on wider frequency ranges, longer minimum times for operation or specific requirements for combined frequency and voltage deviations to ensure the best use of the technical capabilities of a power-generating facility, if it is required to preserve or to restore system security.
- (6) Tripping times for when frequency goes outside of the normal operating range of 59.0 to 61.0 Hz shall be agreed with *Pohnpei Utilities Corporation*. *Pohnpei Utilities Corporation* shall co-ordinate such settings to minimise the risk of cascade tripping and network collapse.
- (7) All *Renewable Power Plants* shall be capable of continuous operation, at up to 100% active power output, within a frequency range of 59.0 to 61.0 Hz and voltage range of 10% either side of nominal voltage.
- (8) The active power output from all Type B and C *Renewable Power Plants* shall not decrease by more than a proportionate decrease when the frequency varies within the range of 57.0 to 59.0 Hz.
- (9) When the frequency on the *Pohnpei Utilities Corporation's* network is higher than 62.0 Hz for longer than 4 seconds, the *Renewable Power Plant* may be disconnected from the grid.
- (10) When the frequency on the *Pohnpei Utilities Corporation's* network is less than 57.0 Hz for longer than 200ms, the *Renewable Power Plant* may be disconnected.
- (11) The *Renewable Power Plant* shall remain connected to the *Pohnpei Utilities Corporation's* network for a rate of change of frequency of up to and including 1.0 Hz per second measured over a rolling window of 500 ms, provided that the network frequency remains within the range of 57.0 to 59.0 Hz.



#### 4.1.1 Synchronising to the *Pohnpei Utilities Corporation's* network

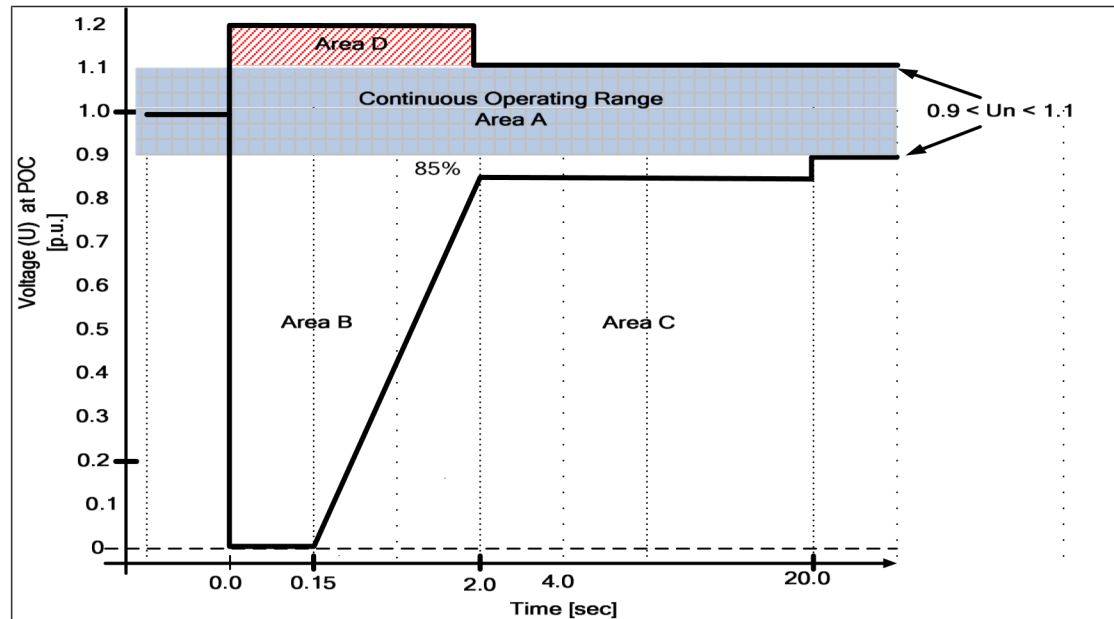
- (1) *Renewable Power Plants* of Type B and C shall only be allowed to connect to the *Pohnpei Utilities Corporation's* network, at the earliest, 3 seconds after:
  - (a) for Type B, the voltage at the *point of connection to the grid* is within  $\pm 10\%$  around the nominal voltage,
  - (b) for Type C, the voltage at the *point of connection to the grid* is within  $\pm 5\%$  around the nominal voltage,
  - (c) frequency in the *Pohnpei Utilities Corporation's* network is within the range of 59.0 Hz and 60.2 Hz.
  - (d) removal of the synchronisation block signal received from the *Pohnpei Utilities Corporation's* SCADA system

#### 4.2 Abnormal Operating Conditions

##### 4.2.1 Tolerance to sudden voltage drops and peaks

- (1) *Renewable Power Plants* of Types B and C shall be designed to withstand and fulfil, at the *point of connection to the grid*, voltage conditions described in this section and illustrated in Figure 1 below.
- (2) The *Renewable Power Plant* shall be designed to withstand voltage drops and peaks, as illustrated in Figure 1 and supply or absorb reactive current within the transient design ratings of the plant.
- (3) The *Renewable Power Plant* shall be able to withstand voltage drops to zero, measured at the *point of connection to the grid*, for a minimum period of 0.150 seconds without disconnecting, as shown in Figure 1.
- (4) The *Renewable Power Plant* shall be able to withstand voltage peaks up to 120% of the nominal voltage, measured at the *point of connection to the grid*, for a minimum period of 2 seconds without disconnecting, as shown in Figure 1.
- (5) Figure 1 shall apply to all types of faults (symmetrical and asymmetrical i.e. one-, two- or three-phase faults) and the bold line shall represent the minimum voltage of all the phases.

**Figure 1: Voltage Ride Through Capability for the Renewable Power Plant of Type B and C**



If the voltage (U) reverts to area A during a fault sequence, subsequent voltage drops shall be regarded as a new fault condition. If several successive fault sequences occur within area B and evolve into area C, disconnection is allowed, see Figure 1.

- (6) In connection with symmetrical fault sequences in areas B and D of Figure 1, the *Renewable Power Plant* shall have the capability of controlling the reactive power. The following requirements shall be complied with:
- (a) **Area A:** The *Renewable Power Plant* shall stay connected to the network and maintain normal production.
  - (b) **Area B:** The *Renewable Power Plant* shall stay connected to the network. In addition, the *Renewable Power Plant* shall provide maximum voltage support by supplying a controlled amount of reactive current so as to ensure that the *Renewable Power Plant* helps to stabilise the voltage.
  - (c) **Area C (Figure 1):** Disconnecting the *Renewable Power Plant* is allowed.
  - (d) **Area D:** The *Renewable Power Plant* shall stay connected to the network and provide maximum voltage support by absorbing a controlled amount of reactive current so as to ensure that the *Renewable Power Plant* helps to stabilise the voltage within the design capability offered by the *Renewable Power Plant*.
- (7) The supply of reactive power has first priority in area B, while the supply of active power has second priority. If possible, active power shall be maintained during voltage drops, but a reduction in active power within the *Renewable Power Plant*'s design specifications is acceptable.

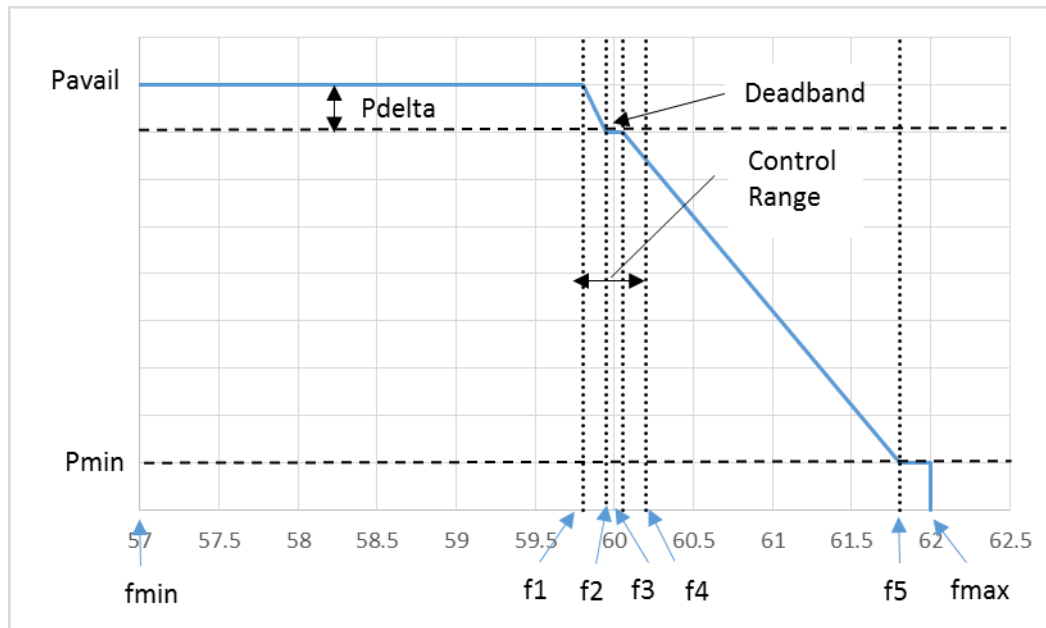
## 5 Frequency Response

- (1) In case of frequency deviations in the *Pohnpei Utilities Corporation's* network, the *Renewable Power Plants* shall be designed to be capable to provide power-frequency response in order to stabilise the grid *frequency*. The metering accuracy for the grid frequency shall be at least  $\pm 10\text{mHz}$ .

### 5.1 Power-frequency response curve for *Renewable Power Plants*

- (1) This subsection applies to all *Renewable Power Plants*.
- (2) *Renewable Power Plants* shall be designed to be capable to provide power-frequency response as illustrated in Figure 2.
- (3) The default settings for  $f_{\min}$ ,  $f_{\max}$ ,  $f_1$  to  $f_5$  shall be as shown in Table 1 for *Renewable Power Plants* unless otherwise agreed with *Pohnpei Utilities Corporation*.
- (4) It shall be possible to set the frequency response control function for all frequency points shown in Figure 2. It shall be possible to set the frequencies  $f_{\min}$ ,  $f_{\max}$ , as well as  $f_1$  to  $f_5$  to any value in the range of 57 - 62 Hz with a minimum accuracy of 10 mHz.
- (5) The *Renewable Power Plants* shall be equipped with the frequency control *droop* settings as illustrated in Figure 2. Each *droop* setting shall be adjustable between 0% and 10%. The actual *droop* setting shall be as agreed with the *Pohnpei Utilities Corporation*.
- (6) The *Pohnpei Utilities Corporation* shall decide and advise the *Renewable Power Plants* on the *droop* settings required to perform the control between the various frequency points.
- (7) If the active power from the *Renewable Power Plants* is regulated downward below the unit's design limit  $P_{\min}$ , shutting-down of individual *Renewable Power Plant units* is allowed.
- (8) It shall be possible to activate and deactivate the frequency response control function in the interval from  $f_{\min}$  to  $f_{\max}$ .
- (9) If the frequency control setpoint ( $P_{\Delta}$ ) is to be changed, such change shall be commenced and be completed no later than 1 second after receipt of an order to change the setpoint.
- (10) The accuracy of the control performed (i.e. change in active power output) and of the setpoint shall not deviate by more than  $\pm 2\%$  of the setpoint value or by  $\pm 0.5\%$  of the rated power, depending on which yields the highest tolerance.

**Figure 2: Frequency response requirement for *Renewable Power Plants***



**Table 1: Frequency Default Settings**

Type	Type A PVPP & WPP	Type B & C PVPP & WPP	Type A, B & C BSPP	Unit
$f_{min}$	57.0	57.0	57.0	Hz
$f_{max}$	62.0	62.0	62.0	Hz
$f_1$	57.0	59.0	59.8	Hz
$f_2$	57.0	59.5	59.9	Hz
$f_3$	60.5	60.5	60.1	Hz
$f_4$	61.0	61.0	60.2	Hz
$f_5$	62.0	62.0	62.0	Hz
$P_{Delta}$	0	As agreed with Utility	100	%

## 5.2 Procedure for setting and changing the power-frequency response curves for Renewable Power Plants

- (1) The *Pohnpei Utilities Corporation* shall give the Renewable Power Plants owner/operator a minimum of 2 weeks if changes to any of the frequency response parameters (i.e.  $f_1$  to  $f_5$ ) are required. The *Renewable Power Plant* owner/operator shall confirm with the *Pohnpei Utilities Corporation* that requested changes have been implemented within two weeks of receiving the *Pohnpei Utilities Corporation's* request.

### 5.3 Synthetic Inertia

- (1) Type B & C asynchronous *Renewable Power Plants* shall be capable of providing synthetic inertia in response to frequency changes, activated in low and/or high frequency conditions by rapidly adjusting the active power injected to or withdrawn from the AC network in order to limit the rate of change of frequency. The requirement shall at least take account of the results of the studies undertaken by *Pohnpei Utilities Corporation* to identify if there is a need to set out minimum inertia.
- (2) The principle of the control system to provide Synthetic Inertia and the associated performance parameters shall be agreed between *Pohnpei Utilities Corporation* and the *Renewable Power Plant* owner.

## 6 Reactive Power Capabilities

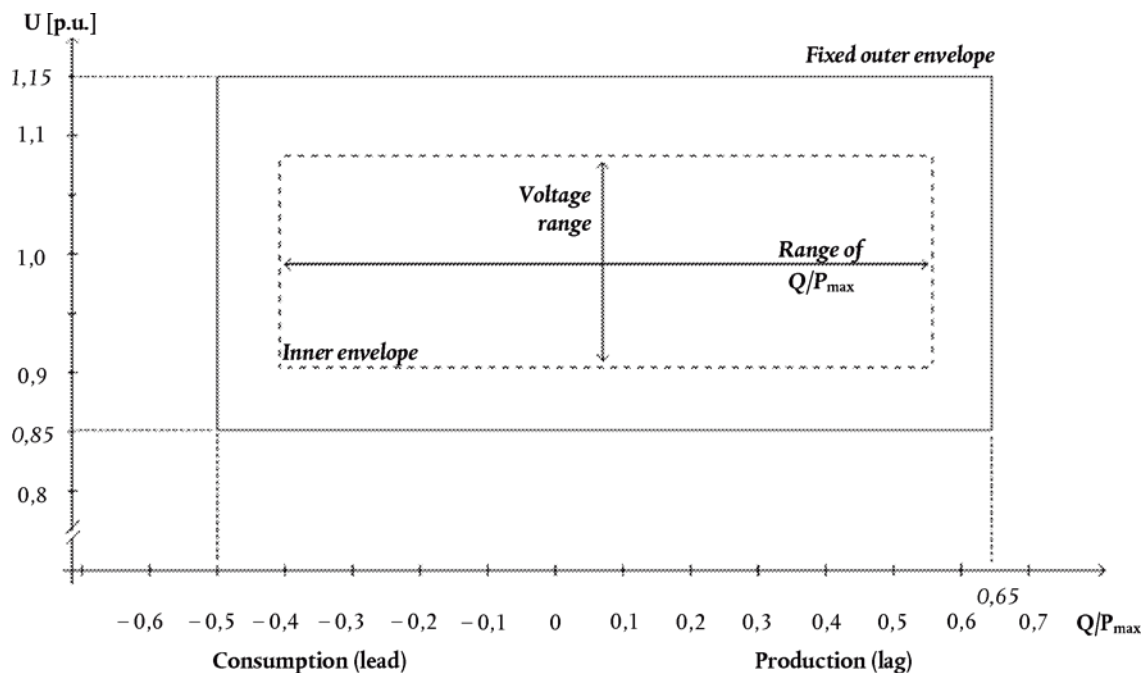
### 6.1 Type A Renewable Power Plants

- (1) Type A *Renewable Power Plants* shall not actively regulate the voltage at the *point of connection*. Type A *Renewable Power Plants* shall not cause the network voltage the *point of connection* to exceed the normal operating voltage limits specified in Paragraph 4.1.

### 6.2 Type B & C Renewable Power Plants

- (1) Type B & C *Renewable Power Plants* shall be designed with the capability to operate in a voltage (V), power factor or reactive power (Q or MVar) control modes as described in section 7 below. The actual operating mode (V, power factor or Q control) as well as the operating point shall be agreed with the *Pohnpei Utilities Corporation*.
- (2) The reactive power capabilities of Type B & C *Renewable Power Plants* at maximum active power transmission capacity shall be capable of providing reactive power at its maximum active power transmission capacity and at every possible operating point below maximum active power transmission capacity. For Type B & C *BSPP* the minimum power shall be the full import capability of the *BSPP* when charging.
- (3) *Renewable Power Plants* shall be designed to supply rated power (MW) for power factors as specified in Table 2 below.
- (4) In addition the *Renewable Power Plants* shall be designed in such a way that the operating point can lie anywhere within the inner envelope in Figure 3.

**Figure 3 U-Q/P<sub>max</sub>-profile of Renewable Power Plants**



The diagram represents the boundaries of the U-Q/P<sub>max</sub>-profile with the voltage at the connection point, expressed in pu, against the ratio of the reactive power (Q) to the maximum capacity (P<sub>max</sub>). The position, size and shape of the inner envelope are indicative.

**Table 2 Parameters for the inner envelope for Type B & C**

Type	Maximum range of Q/P <sub>max</sub>	Maximum range of steady- state voltage level in PU
Type B	0.975	0.225
Type C	0.95	0.225

## **7 Reactive Power and Voltage Control Functions**

- (1) The following requirements shall apply to *Type B & C Renewable Power Plants*.
- (2) The *Renewable Power Plants* shall be equipped with reactive power control functions capable of controlling the reactive power supplied by the *Renewable Power Plants* at the *point of connection* to the grid as well as a voltage control function capable of controlling the voltage at the *point of connection to the grid* via orders using setpoints and gradients.
- (3) Synchronous Renewable Power Plants shall be equipped with a permanent automatic excitation control system that can provide constant alternator terminal voltage at a selectable setpoint without instability over the entire operating range of

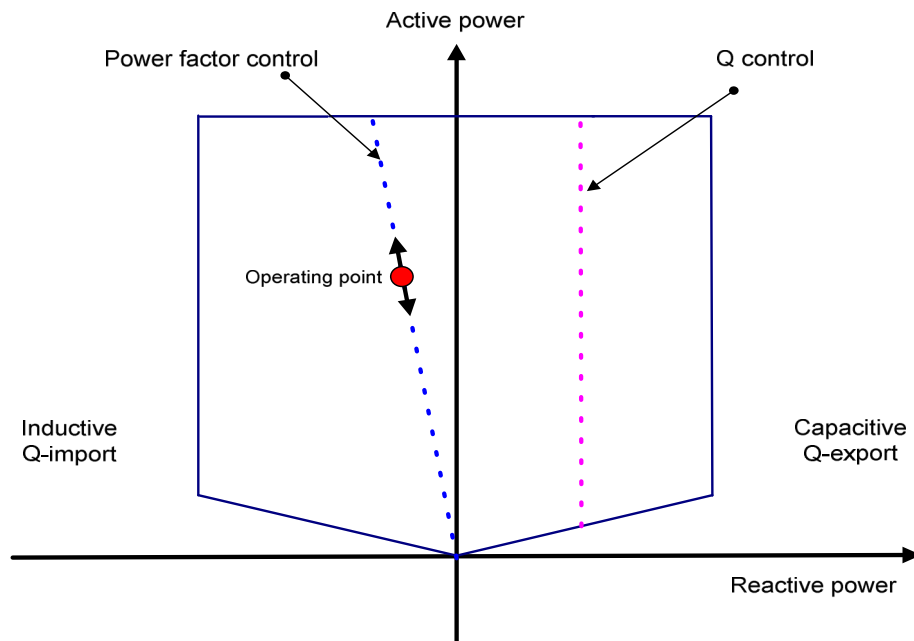
the synchronous Renewable Power Plants. The specifications and performance of the excitation control system shall include:

- (a) bandwidth limitation of the output signal to ensure that the highest frequency of response cannot excite torsional oscillations on other *Power Plants* connected to the network;
  - (b) an underexcitation limiter to prevent the AVR from reducing the alternator excitation to a level which would endanger synchronous stability;
  - (c) an overexcitation limiter to ensure that the alternator excitation is limited to less than the maximum value that can be achieved whilst ensuring that the synchronous *Renewable Power Plant* is operating within its design limits;
  - (d) a stator current limiter;
- (4) The reactive power and voltage control functions are mutually exclusive, which means that only one of the three functions mentioned below can be activated at a time.
- (a) Voltage control
  - (b) Power Factor control
  - (c) Q control
- (5) The control function and applied parameter settings for reactive power and voltage control functions shall be determined by the *Pohnpei Utilities Corporation* and implemented by the *Renewable Power Plants*. The agreed control functions shall be documented in the *operating agreement*.

## 7.1 Reactive power (Q) Control

- (1) Q control is a control function controlling the reactive power supply and absorption at the point of connection to the grid independently of the active power and the voltage. This control function is illustrated in Figure 4 as a vertical line.
- (2) If the Q control setpoint is to be changed by the *Pohnpei Utilities Corporation*, the *Renewable Power Plant* shall update its echo analogue setpoint value in response to the new value within 1 second. The *Renewable Power Plants* shall respond to the new set point within 30 seconds after receipt of an order to change the setpoint.
- (3) The accuracy of the control performed and of the setpoint shall not deviate by more than  $\pm 2\%$  of the setpoint value or by  $\pm 0.5\%$  of maximum reactive power, depending on which yields the highest tolerance.
- (4) The *Renewable Power Plants* shall be able to receive a Q setpoint with an accuracy of at least  $\pm 0.5\%$  of maximum reactive power.

**Figure 4: Reactive power control functions for the *Renewable Power Plants***



## 7.2 Power Factor Control

- (1) Power Factor Control is a control function controlling the reactive power proportionally to the active power at the point of connection to the grid. This is illustrated in Figure 4 by a line with a constant gradient.
- (2) If the power factor setpoint is to be changed by the *Pohnpei Utilities Corporation*, the *Renewable Power Plant* shall update its echo analogue setpoint value to in response to the new value within 1 second. The *Renewable Power Plant* shall respond to the new set point within 30 seconds after receipt of an order to change the setpoint.
- (3) The accuracy of the control performed and of the setpoint shall not deviate by more than  $\pm 0.02$ .

## 7.3 Voltage Control

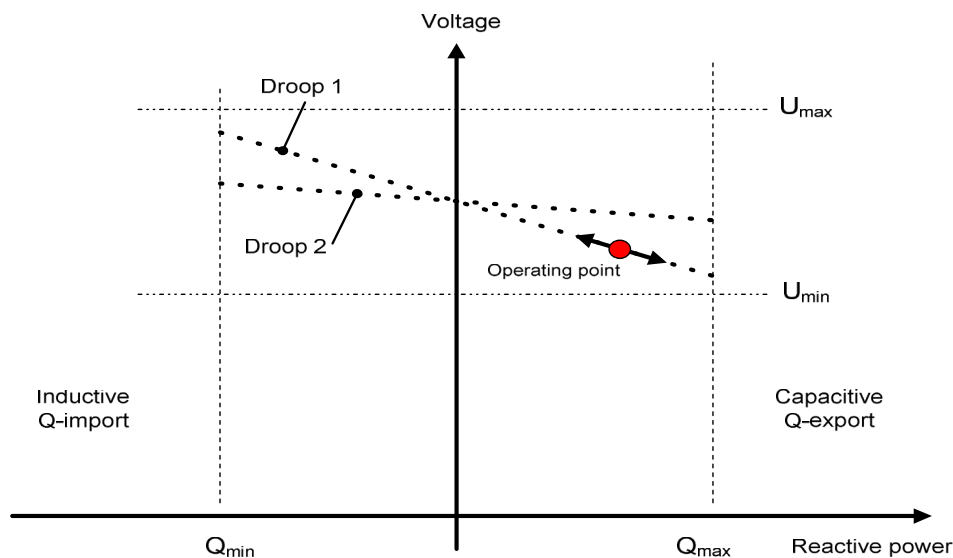
- (1) Voltage control is a control function controlling the voltage at the point of connection to the grid.
- (2) If the voltage setpoint is to be changed, such change shall be commenced within 1 second and completed no later than 30 seconds after receipt of an order to change the setpoint.
- (3) The accuracy of the voltage setpoint shall be within  $\pm 0.5\%$  of nominal voltage, and the accuracy of the control performed shall not deviate by more than  $\pm 2\%$  of the required injection or absorption of reactive power according to *droop* characteristics as defined in Figure 5.
- (4) The individual *Renewable Power Plant* shall be able to perform the control within its dynamic range and voltage limit with the *droop* configured as shown in Figure 5. In



this context, *droop* is the voltage change (p.u.) caused by a change in reactive power (p.u.).

- (5) When the voltage control has reached the *Renewable Power Plant's* dynamic design limits, the control function shall await possible overall control from the tap changer or other voltage control functions.
- (6) Overall voltage coordination shall be handled by the *Pohnpei Utilities Corporation*.

**Figure 5: Voltage control for the *Renewable Power Plant***



## 8 Power Quality

- (1) The following requirements shall apply to all *Renewable Power Plants*.
- (2) *Power quality* and voltage regulation impact shall be monitored at the point of connection to the grid and shall include an assessment of the impact on *power quality* from the *Renewable Power Plant* concerning the following disturbances at the point of connection to the grid:
  - (a) voltage fluctuations:
    - (i) rapid voltage changes
    - (ii) flicker
  - (b) high-frequency currents and voltages:
    - (i) harmonics
    - (ii) inter-harmonics

- (iii) disturbances greater than 2 kHz.
- (c) unbalanced currents and voltages:
  - (i) deviation in magnitude between three phases
  - (ii) deviation in angle separation from 120° between three phases.
- (3) The *Renewable Power Plant* and its interconnection system shall not inject dc current greater than 0.5% of the full rated output current at the point of connection.
- (4) When the *Renewable Power Plant* is serving balanced linear loads, harmonic current injection into the network at the point of connection shall not exceed the limits stated below in Table 3. The harmonic current injections shall be exclusive of any harmonic currents due to harmonic voltage distortion present in the network without the *Renewable Power Plant* connected.

**Table 3—Maximum harmonic current distortion in percent of current (I)<sup>a</sup>**

Individual harmonic order h (odd harmonics) <sup>b</sup>	$h < 11$	$11 \leq h < 17$	$17 \leq h < 23$	$23 \leq h < 35$	$35 \leq h$	Total demand distortion (TDD)
Percent (%)	4.0	2.0	1.5	0.6	0.3	5.0

<sup>a</sup> I = the greater of the local network maximum load current integrated demand (15 or 30 minutes) without the RPP unit, or the RPP unit rated current capacity (transformed to the point of connection when a transformer exists between the RPP unit and the point of connection).

<sup>b</sup> Even harmonics are limited to 25% of the odd harmonic limits above.

- (5) *Power quality* and voltage regulation impact shall be monitored at the point of connection to the grid.
- (6) Voltage and current quality distortion levels emitted by the *Renewable Power Plant* at the point of connection to the grid shall not exceed the apportioned limits as determined by the *Pohnpei Utilities Corporation*.
- (7) The *Renewable Power Plant* shall ensure that the *plant* is designed, configured and implemented in such a way that the specified emission limit values are not exceeded.
- (8) The maximum allowable voltage change at the *Renewable Power Plant* after a switching operation by the *plant* (e.g. of a compensation devices) shall not be greater than 2%.

## **9 Islanding**

- (1) For an unintentional island in which the *Renewable Power Plant* energizes a portion of the network through the *point of connection*, the *Renewable Power Plant* interconnection system shall detect the island and cease to energize the network within two seconds of the formation of an island.

- (2) *Renewable Power Plant* can be requested to intentionally island under certain conditions. The *Renewable Power Plant* requested to intentionally island shall have the facilities to detect an island condition, and have the capability to actively control frequency and / or voltage. *Pohnpei Utilities Corporation* shall provide the conditions and requirements from the for *Renewable Power Plant* intentional islanding.

## **10 Protection and Fault levels**

- (1) Unless otherwise stated, requirements in this section apply to all *Types of Renewable Power Plants*.
- (2) Protection functions shall be available to protect the *Renewable Power Plant* and to ensure a stable network.
- (3) The *Renewable Power Plants* shall ensure that the plant is dimensioned and equipped with the necessary protection functions such that the *plant* is protected against damage due to faults and incidents in the network.
- (4) Protection schemes may cover the following aspects:
- external and internal short circuit,
  - asymmetric load (negative phase sequence),
  - stator and rotor overload,
  - over-/underexcitation,
  - over-/undervoltage at the connection point,
  - over-/undervoltage at the alternator terminals,
  - inrush current,
  - asynchronous operation (pole slip),
  - protection against inadmissible shaft torsions (for example, subsynchronous resonance),
  - *power-generating module* line protection,
  - unit transformer protection,
  - back-up against protection and switchgear malfunction,
  - overfluxing (U/f),
  - inverse power,
  - rate of change of frequency, and
  - neutral voltage displacement.
- (5) The *Pohnpei Utilities Corporation* may request that the set values for protection functions be changed following commissioning if it is deemed to be of importance to the operation of the network. However, such change shall not result in the *Renewable Power Plants* being exposed to negative impacts from the network lying outside of the design requirements.
- (6) The *Pohnpei Utilities Corporation* shall inform the *Renewable Power Plants* owners/operators of the highest and lowest short-circuit current that can be expected at the point of connection to the grid as well as any other information about the network as may be necessary to define the *Renewable Power Plant's* protection functions.

## **11 Active Power Constraint Functions**

- (1) This section shall apply to Types B and C *Renewable Power Plants*.
- (2) For system security reasons it may be necessary for the *Pohnpei Utilities Corporation* to curtail the *Renewable Power Plant's* active power output.
- (3) The *Renewable Power Plants* shall be capable of:
  - (a) operating the plant at a reduced level if active power has been curtailed by the *Pohnpei Utilities Corporation* for system security reasons and for frequency control.
  - (b) receiving a telemetered MW Curtailment set-point sent from the *Pohnpei Utilities Corporation*.
- (4) The *Renewable Power Plants* shall be equipped with constraint functions, i.e. supplementary active power control functions. The constraint functions are used to avoid imbalances in the *Pohnpei Utilities Corporation's* network or overloading of the network in connection with the reconfiguration of the network in critical or unstable situations or the like, as illustrated in Figure 6.
- (5) Activation of the active power constraint functions shall be agreed with the *Pohnpei Utilities Corporation*.

The required constraint functions are as follows:

- (a) Absolute production constraint
- (b) Delta production constraint
- (c) Power gradient constraint
- (6) The required constraint functions are described in the following sections.

### **11.1 Absolute Production Constraint**

- (1) An Absolute Production Constraint is used to constrain the output active power from the *Renewable Power Plants* to a predefined power MW limit at the point of connection to the grid. This is typically used to protect the network against overloading and for frequency control.
- (2) If the setpoint for the Absolute Production Constraint is to be changed, such change shall be commenced within 1 second and completed not later than 2 seconds after receipt of an order to change the setpoint.
- (3) The accuracy of the control performed and of the setpoint shall not deviate by more than  $\pm 2\%$  of the setpoint value or by  $\pm 0.5\%$  of the *rated power*, depending on which yields the highest tolerance.

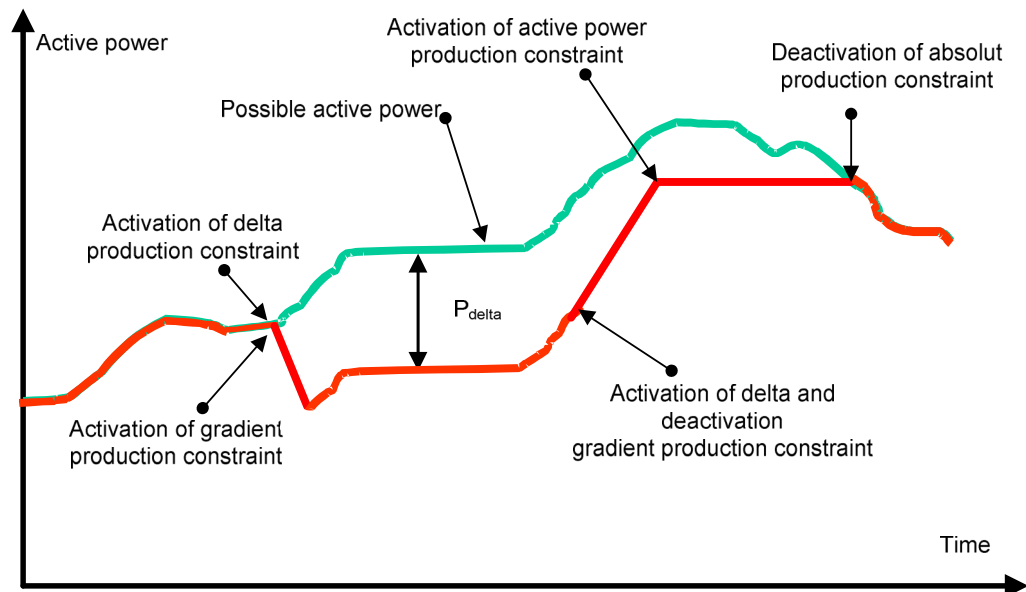
## 11.2 Delta Production Constraint

- (1) A Delta Production Constraint is used to constrain the active power from the *Renewable Power Plants* to a required constant value in proportion to the possible active power.
- (2) A Delta Production Constraint is typically used to establish a control reserve for control purposes in connection with primary frequency control.
- (3) If the setpoint for the Delta Production Constraint is to be changed, such change shall be commenced within 1 second and completed no later than 2 seconds after receipt of an order to change the setpoint.
- (4) The accuracy of the control performed and of the setpoint shall not deviate by more than  $\pm 2\%$  of the setpoint value or by  $\pm 0.5\%$  of the rated power, depending on which yields the highest tolerance.

## 11.3 Power Gradient Constraint

- (1) A Power Gradient Constraint is used to limit the maximum ramp rates by which the active power can be changed in the event of changes in primary renewable energy supply or the setpoints for the *Renewable Power Plant*. A Power Gradient Constraint is typically used for reasons of system operation to prevent changes in active power from impacting the stability of the network.
- (2) If the setpoint for the Power Gradient Constraint is to be changed, such change shall be commenced within 1 second and completed no later than 2 seconds after receipt of an order to change the setpoint.
- (3) The accuracy of the control performed and of the setpoint shall not deviate by more than  $\pm 2\%$  of the setpoint value or by  $\pm 0.5\%$  of the *rated power*, depending on which yields the highest tolerance.
- (4) The active power constraint functions are illustrated in **Figure 6**.

**Figure 6: Active power control functions for a Renewable Power Plant**



## 12 Control Function Requirements

- (1) *Renewable Power Plants* shall be equipped with the control functions specified in Table 4. The purpose of the various control functions is to ensure overall control and monitoring of the *Renewable Power Plant's* generation.
- (2) The *Renewable Power Plants* control system shall be capable of controlling the ramp rate of its active power output with a maximum MW per minute ramp rate set by the *Pohnpei Utilities Corporation*.
- (3) These ramp rate settings shall be applicable for all ranges of operation including positive ramp rate during start up, positive ramp rate only during normal operation and negative ramp rate during controlled shut down. They shall not apply to frequency regulation.
- (4) The *Renewable Power Plants* shall not perform any frequency response or voltage control functions without having entered into a specific agreement to this effect with the *Pohnpei Utilities Corporation*.
- (5) The specifications and regulation functions specified shall comply with the international standard IEC 61400-25-2.

**Table 4: Control functions required for *Renewable Power Plants***

Control function	Type A	Type B	Type C
Frequency control	X	X	X
Absolute production constraint	-	X	X

Control function	Type A	Type B	Type C
Delta production constraint	-	X	X
Power gradient constraint	-	X	X
Q control	-	X	X
Power factor control	-	X	X
Voltage control	-	X	X

### **13 Signals, Communications & Control**

- (1) All signals shall be made available at the *point of connection to the grid* by the *Renewable Power Plants*.

#### **13.1 Signals from the *Renewable Power Plants* available at the point of connection to the grid**

- (1) This section shall apply to *Renewable Power Plants* of *Type B and C*.
- (2) Signals from the *Renewable Power Plants* to the *Pohnpei Utilities Corporation* shall be broken up into a number of logical groups depending on functionality.
- (3) The following signal list groups shall apply:

(a) ***Signals List #1 – General***

In addition, *Renewable Power Plants* shall be required to provide certain signals from Signals Lists 2, 3, 4 and 5. These lists relate to:

- (b) ***Signals List #2 – Renewable Power Plant Availability Estimate;***
- (c) ***Signals List #3 – Renewable Power Plant MW Curtailment data;***
- (d) ***Signals List #4 – Renewable Power Plant frequency response settings***
- (e) ***Signals List #5 – Renewable Power Plant meteorological data.***

##### **13.1.1 Signals List #1 – General**

- (1) The *Renewable Power Plants* shall make the following signals available at the *Pohnpei Utilities Corporation* designated *communication gateway equipment* located at the *plant's* site:
- (a) Actual sent-out (MW) at the point of connection to the grid
- (b) Active Power Ramp rate of the entire *Renewable Power Plant*
- (c) Reactive Power Import/Export (+/-MVAR) at the point of connection to the grid

- (d) Reactive power range upper and lower limits
- (e) *Power Factor*
- (f) *Voltage output*
- (g) *Echo MW set point*
- (h) *Echo MVar set point*
- (i) *Echo Voltage set point*

### **13.1.2 Signals List #2 – Renewable Power Plants Current Availability Estimates**

- (1) The *Renewable Power Plants* shall make available the following signals at the *Pohnpei Utilities Corporation* designated *communication gateway equipment* located at the *plant* site:
  - (a) Current available maximum MW updated every second.
  - (b) Current available MVar updated every second.

### **13.1.3 Signals List #3 – RPP MW Curtailment Data**

- (1) The *Renewable Power Plants* shall make the following signals available at a designated *communication gateway equipment* located at the *plant's* site:
  - (a) *Plant* MW Curtailment facility status indication (ON/OFF) as a double bit point. This is a controllable point which is set on or off by the *Pohnpei Utilities Corporation*. When set "On" the *plant* shall then clarify and initiate the curtailment based on the curtailment setpoint value below.
  - (b) Curtailment in progress digital feedback. This single bit point will be set high by the *plant* while the facility is in the process of curtailing its output.
  - (c) *Plant's* MW Curtailment Set-point value (MW- feedback).
- (2) In the event of a curtailment, the Pohnpei Utilities Corporation will pulse the curtailment setpoint value down. The *plant's* response to the changed curtailment value will be echoed by changing the corresponding echo MW value. This will provide feedback that the *plant* is responding to the curtailment request.

### **13.1.4 Signals List #4 – Frequency Response System Settings**

- (1) The *Renewable Power Plants* shall make the following signals available at a designated communication gateway equipment located at the *plant's* site:
  - (a) *Frequency Response System* mode status indication (ON/OFF) as a double bit point



### 13.1.5 Signals List #5 – Renewable Power Plants Meteorological Data.

- (1) *Renewable Power Plants* shall make the following signals available at the *Pohnpei Utilities Corporation's* designated communication gateway equipment located at the *plant* site:
  - (a) Wind speed (within 75% of the hub height) – measured signal in meters/second (for *WPP* only)
  - (b) Wind direction within 75% of the hub height) – measured signal in degrees from true north(0-359) (for *WPP* only)
  - (c) Air temperature- measured signal in degrees centigrade (-20 to 50)
  - (d) Air pressure- measured signal in millibar (800 to 1400).
  - (e) Air density (for *WPP* only)
  - (f) Solar radiation (for *PVPP* only)
- (2) The meteorological data signals shall be provided by a dedicated Meteorological Mast located at the *plant's* site or, where possible and preferable to do so, data from a means of the same or better accuracy.
- (3) Energy resource conversion data for the facility (e.g. MW/ wind speed) for the various resource inputs to enable the *Pohnpei Utilities Corporation* to derive a graph of the full range of the facilities output capabilities. An update will be sent to the *Pohnpei Utilities Corporation* following any changes in the output capability of the facility.

### 13.2 Update Rates

- (1) Signals shall be updated at the following rates:
  - (a) Analog Signals at a rate of 1 second
  - (b) Digital Signals at the rate of 1 second.
  - (c) Meteorological data once a minute

### 13.3 Control Signals Sent from *Pohnpei Utilities Corporation* to the *Renewable Power Plants*

The control signals described below shall be sent from *Pohnpei Utilities Corporation* to the *Type B and C Renewable Power Plants*. The *plants* shall be capable of receiving these signals and acting accordingly.

#### 13.3.1 Active-Power Control

- (1) An *Active-Power Control* setpoint signal shall be sent by *Pohnpei Utilities Corporation* to the *Renewable Power Plant's* control system.

- (2) This setpoint shall define the maximum Active Power output permitted from the *plant*. The *plant's* control system shall be capable of receiving this signal and acting accordingly to achieve the desired change in Active Power output.
- (3) The *Renewable Power Plants* shall make it possible for the *Pohnpei Utilities Corporation* to remotely enable/disable the Active-Power control function in the plant's control system.

### **13.3.2 Connection Point CB Trip facility**

- (1) A facility shall be provided by the *Pohnpei Utilities Corporation* to facilitate the disconnection of the *plant*. It shall be possible for Pohnpei Utilities Corporation to send a trip signal to the circuit breaker at the *HV* side of *the point of connection to the grid*.

### **13.3.3 Synchronisation block signal**

- (1) A Synchronisation block signal shall be sent by *Pohnpei Utilities Corporation* to the *Renewable Power Plant's* control system to prevent the *Renewable Power Plant* from synchronising when system conditions dictate this.

### **13.4 Renewable Power Plants MW availability declaration**

- (1) The *Renewable Power Plant* shall submit *plant's* MW availability declarations whenever changes in MW availability occur or are predicted to occur. These declarations shall be submitted by means of an electronic interface in accordance with the requirements of *Pohnpei Utilities Corporation's* data system.

### **13.5 Data Communications Specifications**

- (1) The *Renewable Power Plant* shall have external communication gateway equipment that can communicate with a minimum of two simultaneous SCADA Masters, independently from what is done inside the *plant*.
- (2) The location of the communication gateway equipment shall be agreed between affected participants in the connection agreement.
- (3) The necessary communications links, communications protocol and the requirement for analogue or digital signals shall be specified by the *Pohnpei Utilities Corporation* as appropriate before a connection agreement is signed between the *plant* and the *Pohnpei Utilities Corporation*.
- (4) *Active Power Curtailment* or *Voltage Regulation* facilities at the *plant* shall be tested once a quarter. It is essential that facilities exist to allow the testing of the functionality without tripping the actual equipment.
- (5) Where signals or indications required to be provided by the *plant* become unavailable or do not comply with applicable standards due to failure of the *plant* equipment or any other reason under the control of the *plant owner/operator*, the *plant owner/operator* shall restore or correct the signals and/or indications within 24 hours.

## **14 Testing and Compliance Monitoring**

- (1) All *Renewable Power Plants* shall demonstrate compliance to all applicable requirements specified in this grid connection code and any other applicable code or standard, before being allowed to connect to the network.
- (2) The *plant* shall review, and confirm to the *Pohnpei Utilities Corporation*, compliance by the *plant* with every requirements of this code.
- (3) The *Renewable Power Plant* shall conduct tests or studies to demonstrate that the *plant* complies with each of the requirements of this code.
- (4) The *Renewable Power Plant* shall continuously monitor its compliance in all material respects with all the connection conditions of this code.
- (5) Each *Renewable Power Plant* shall submit to the *Pohnpei Utilities Corporation* a detailed test procedure, emphasising system impact, for each relevant part of this code prior to every test.
- (6) If *Renewable Power Plant* determines, from tests or otherwise, that the *plant* is not complying with one or more sections of this code, then the *plant owner/operator* shall (within 1 hour of being aware):
  - (a) notify the *Pohnpei Utilities Corporation* of that fact,
  - (b) advise the *Pohnpei Utilities Corporation* of the remedial steps it proposes to take to ensure that the relevant *plant* can comply with this code and the proposed timetable for implementing those steps,
  - (c) diligently take such remedial action to ensure that the relevant *plant* can comply with this code; the *plant owner/operator* shall regularly report in writing to the *Pohnpei Utilities Corporation* on its progress in implementing the remedial action, and
  - (d) after taking remedial action as described above, demonstrate to the reasonable satisfaction of the *Pohnpei Utilities Corporation* that the relevant *plant* is then complying with this code.
- (7) The *Pohnpei Utilities Corporation* may issue an instruction requiring the *plant* to carry out a test to demonstrate that the relevant *plant* with the code requirements. A *plant* may not refuse such an instruction, provided it is issued timeously and there are reasonable grounds for suspecting non-compliance.
- (8) The *plant owner/operator* shall keep records relating to the compliance of the *plant* with each section of this grid connection code, or any other code applicable to that *plant*, setting out such information that the *Pohnpei Utilities Corporation* reasonably requires for assessing power system performance, including actual *plant* performance during abnormal conditions. Records shall be kept for a minimum of 5 years (unless otherwise specified in the code) commencing from the date the information was created.

## **15 Reporting to Pohnpei Utilities Corporation**

- (1) The *Renewable Power Plant* shall design the system and maintain records *such* that the following information can be provided to the *Pohnpei Utilities Corporation* on a monthly basis in an electronic spread sheet format:
  - (a) Non-renewable/supplementary fuel used by the power plant.
  - (b) Actual hourly availability and output energy to the grid that occurred and the average primary resource for that hour.
  - (c) Actual hourly electricity imports from all sources as applicable.
  - (d) Any curtailed energy during the month.
- (2) These reports are to be submitted before the 15th of the following month to *Pohnpei Utilities Corporation* via an email.
- (3) These reports should also include details of incidents relating any unavailability of the network which prevented the *plant* from generating.
- (4) The *Pohnpei Utilities Corporation* requires suitable and accurate dynamic models, in the template specified by the requesting party applying for a connection to the *network*, in order to assess reliably the impact of the *plant* proposed installation on the dynamic performance and security and stability of the power system.
- (5) The required dynamic models must operate under RMS simulation to replicate the performance of the *plant* or individual units for analysis of the following network aspects:
  - (a) *Plant's* impact on network voltage stability
  - (b) *Plant's* impact on Quality of Supply at *point of connection*
  - (c) *Plant's* impact on network protection co-ordination
  - (d) *Plant's FRT* (Fault Ride Through) capability for different types of faults and positions (h) *plant's* response to various system phenomena such as:
    - (i) switching on the network
    - (ii) power swings
    - (iii) small signal instabilities
- (6) *Plant's* data exchange shall be a time-based process.
  - (a) **First stage** (during the application for connection)
    - (i) The following information shall be submitted by the *plant owner/operator* to the *Pohnpei Utilities Corporation*, as applicable:
      - Physical location (including the GPS coordinates)

- Site Plan
  - Number of wind turbines or *units* to be connected
  - MW output per turbine or *unit*
  - Initial phase MW value
  - Final phase MW value and timelines
  - Any other information that the service provider may reasonably require
- (ii) For the detailed *plant* design, the *Pohnpei Utilities Corporation* shall make available to the *plant owner/operator* at least the following information:
- *Point of connection* to the grid including the nominal voltages,
  - Expected fault levels,
  - The network service provider's connection between the Point of connection to the grid and the *plant*,
  - The busbar layout of the point of connection to the grid and *point of connection* substations,
  - The portion of the network service provider's grid that will allow accurate and sufficient studies to design the *plant* to meet the Grid Code. This information shall include:
    - Positive and zero sequence parameters of the relevant network service provider's transmission and distribution, transformers, reactors, capacitors and other relevant equipment
    - The connection of the various lines transformers, reactors and capacitors etc.
- (b) **Second stage** (after detailed *plant* designs have been completed but before commissioning the *plant*)
- (i) During this stage, the *plant* shall provide information on:
- Selected *plant* technology data.
  - Fault ride through capability and harmonic studies test report
  - Generic test model and dynamic modelling data per wind turbine or *unit* as from the type approval and tests result
- (c) **Third stage** (after commissioning and optimisation of the *plant*)
- (i) During this stage, the *plant* is compelled to provide information on:

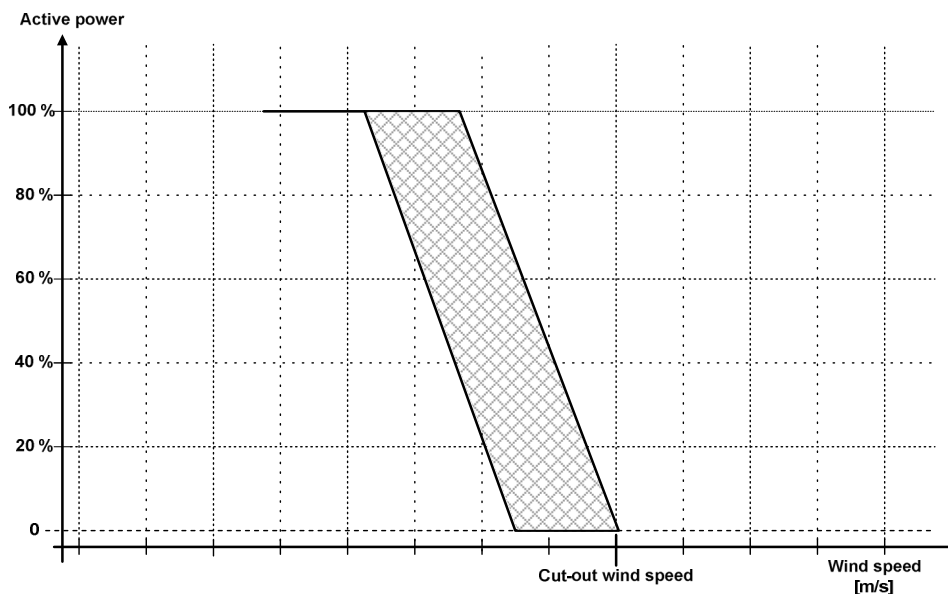
- A validated *plant's* electrical dynamic simulation model using commissioning test data and measurements
  - Test measurement data in the format agreed between the *plant* and the Pohnpei Utilities Corporation, as applicable.
- (7) The dynamic modelling data shall be provided in a format as may be agreed between the *plant owner/operator* and the Pohnpei Utilities Corporation, as applicable.
- (8) In addition, the *Renewable Power Plant* Generator shall provide the Pohnpei Utilities Corporation with operational data as prescribed in **Appendix 4**.

## 16 Appendix 1 - Wind Power Plants

### 16.1 High Wind Curtailment

- (1) It shall be possible to continuously downward regulate the active power supplied by the *plant* to an arbitrary value in the interval from 100% to at least 40% of the rated power. When downward regulation is performed, the shutting-down of individual wind turbine *generator* systems is allowed so that the load characteristic is followed as well as possible.
- (2) The *Wind Power Plant* shall stay connected to the *network* at average wind speeds below a predefined cut-out wind speed. The cut-out wind speed shall as a minimum be 25 m/s, based on the wind speed measured as an average value over a 10-minute period. To prevent instability in the *network*, the *Wind Power Plant* shall be equipped with an automatic downward regulation function making it possible to avoid a temporary interruption of the active power production at wind speeds close to the cut-out wind speed.
- (3) Downward regulation shall be performed as continuous or discrete regulation. Discrete regulation shall have a step size of maximum 25% of the rated power within the hatched area shown in Figure 7. When downward regulation is being performed, the shutting down of individual wind turbine *generator* systems is allowed. The downward regulation band shall be agreed with the *Pohnpei Utilities Corporation* upon commissioning of the wind power plant.

**Figure 7: Downward regulation of active power at high renewable speeds**



## **17 Appendix 2 - Photovoltaic Power Plants**

No special requirements for solar PV except the general requirement specified in this code.



### **Appendix 3 - *Battery Power Plants***

No special requirements for *Battery Power Plants* except the general requirement specified in this code.

## 18 Appendix 4 - Documentation

### 18.1 Master Data

Description	Text
<b>Identification:</b>	
Name of <i>electricity supply undertaking</i>	
Plant name	
ID number	
Planned commissioning	
<b>Technical data:</b>	
Manufacturer	
Type designation (model)	
Type approval	
Approval authority	
Installed kW ( <i>rated power</i> )	
Cos $\phi$ ( <i>rated power</i> )	
Cos $\phi$ (20% <i>rated power</i> )	
Cos $\phi$ (no load)	
3-phase short-circuit current immediately in front of the <i>power plant</i> (RMS)	
<i>Point of connection</i>	
Voltage level	

Description	Text
<b><i>Plant address:</i></b>	
Contact person (technical)	
Address1	
House number	
Letter	
Postal code	
BBR municipality	
X/Y coordinates	
Title number	
Owners' association on titled land	
<b><i>Owner:</i></b>	
C ID number	
Company name	
Contact person (administrative)	
Address1	
House number	
Letter	
Floor	
To the right/left	
Postal code	
Email address	

## 18.2 Technical Documentation

### 18.2.1 Step-Up Transformer

Description	Value
Make	
Type	
Comments	

Description	Symbol	Unit	Value
Nominal apparent power (1 p.u.)	$S_n$	MVA	
Nominal primary voltage (1 p.u.)	$U_p$	kV	
Nominal secondary voltage	$U_s$	kV	
Coupling designation, eg Dyn11	-	-	
Step switch location	-	-	<div>Primary side</div> <div>Secondary side</div>
Step switch, additional voltage per step	$du_{tp}$	%/trin	
Step switch, phase angle of additional voltage per step:	$\phi_{i_{tp}}$	degree/step	
Step switch, lowest position	$n_{tpmin}$	-	
Step switch, highest position	$n_{tpmax}$	-	
Step switch, neutral position	$n_{tp0}$	-	
Short-circuit voltage, synchronous	$u_k$	%	
Copper loss	$P_{cu}$	kW	
Short-circuit voltage, zero system	$u_{k0}$	%	
Resistive short-circuit voltage, zero sequence system	$u_{kr0}$	%	
No-load current	$I_0$	%	
No-load loss	$P_0$	%	

### 18.2.2 Single Line Diagram Representation

- (1) This applies to all *Renewable Power Plants* of Type B and C.
- (2) A single-line diagram representation of the plant shall be created, with indication of *point of connection to the grid*, metering points, including settlement metering, limits of ownership and operational supervisor limits/limits of liability. In addition, the type designation for the switchgear used shall be stated so as to make it possible to identify the correct connection terminals.
- (3) In instances when a single-line diagram representation is included in the grid use agreement between the *Renewable Power Plant* and Pohnpei Utilities Corporation, the grid *connection agreement* can be enclosed as documentation.

### 18.2.3 PQ Diagram

- (1) This applies to all *Renewable Power Plants* of Type B and C.

## **19 Appendix 5 – Compliance test specifications**

### **19.1 Introduction**

This section specifies the procedures to be followed in carrying out testing to verify compliance with this *Code*.

## 19.2 Test procedures

### 19.3 Renewable Power Plants protection function verification

Parameter	Reference	Description
Protection function and settings	Section 9	<p><b>APPLICABILITY AND FREQUENCY</b></p> <p>All new <i>Renewable Power Plants</i> coming on line or at which major refurbishment or upgrades of protection systems have taken place.</p> <p><b>Routine review:</b> All <i>plants</i> to confirm compliance every six years.</p> <p><b>PURPOSE</b></p> <p>To ensure that the relevant protection functions in the <i>Renewable Power Plants</i> are coordinated and aligned with the system requirements.</p> <p><b>PROCEDURE</b></p> <ol style="list-style-type: none"> <li>1. Establish the system protection function and associated trip level requirements from the <i>Pohnpei Utilities Corporation</i>.</li> <li>2. Derive protection functions and settings that match the <i>Renewable Power Plant</i> and system requirements.</li> <li>3. Confirm the stability of each protection function for all relevant system conditions.</li> <li>4. Document the details of the trip levels and stability calculations for each protection function.</li> <li>5. Convert protection tripping levels for each protection function into a per <i>unit</i> base.</li> <li>6. Consolidate all settings in a per <i>unit</i> base for all protection functions in one document.</li> <li>7. Derive actual relay dial setting details and document the relay setting sheet for all protection functions.</li> <li>8. Document the position of each protection function on one single line diagram of the generating <i>unit</i> and associated connections.</li> <li>9. Document the tripping functions for each tripping function on one tripping logic diagram.</li> <li>10. Consolidate detail setting calculations, per unit setting sheets, relay setting sheets, plant base information on which the settings are based, tripping logic diagram, protection function single line diagram and relevant</li> </ol>

		<p>protection relay manufacturers' information into one document.</p> <p>11. Submit to the <i>Pohnpei Utilities Corporation</i> for its acceptance and update.</p>
Protection function and settings (cont.)	Section 9 (cont.)	<p><b>Review:</b></p> <p>1. Review Items 1 to 10 above.</p> <p>Submit to the <i>Pohnpei Utilities Corporation</i> for its acceptance and update.</p> <p>Provide the <i>Pohnpei Utilities Corporation</i> with one original master copy and one working copy.</p> <p><b>ACCEPTANCE CRITERIA</b></p> <p>All protection functions are set to meet the necessary protection requirements of the <i>plant</i> with a minimal margin, optimal fault clearing times and maximum plant availability.</p> <p>Submit a report to the <i>Pohnpei Utilities Corporation</i> one month after commissioning and six-yearly for routine tests.</p>



### 19.3.1 Renewable Power Plants protection integrity verification

Parameter	Reference	Description
Protection integrity	Section 9	<p><b>APPLICABILITY AND FREQUENCY</b></p> <p>All new <i>Renewable Power Plants</i> coming on line and all other <i>power stations</i> after major works of refurbishment of protection or related plant. Also, when modification or work has been done to the protection, items 2 to 5 must be carried out. This may, however, be limited to the areas worked on or modified.</p> <p><b>Routine review:</b> All <i>plants</i> on: item 1 below: Review and confirm every 6 years Item 2, and 3 below: at least every 12 years.</p> <p><b>PURPOSE</b></p> <p>To confirm that the protection has been wired and functions according to the specifications.</p> <p><b>PROCEDURE</b></p> <ol style="list-style-type: none"> <li>1. Apply final settings as per agreed documentation to all protection functions.</li> <li>2. With the <i>unit</i> off load and de-energized, inject appropriate signals into every protection function and confirm correct operation and correct calibration. Document all protection function operations.</li> <li>3. Carry out trip testing of all protection functions, from origin (e.g. Buchholz relay) to all tripping output devices (e.g. HV breaker). Document all trip test responses.</li> <li>4. Apply short-circuits at all relevant protection zones and with <i>generator</i> at nominal speed excite <i>generator</i> slowly, record currents at all relevant protection functions and confirm correct operation of all relevant protection functions. Document all readings and responses. Remove all short-circuits.</li> <li>5. With the <i>Renewable Power Plants</i> at nominal production. Confirm correct operation and correct calibration of all protection functions. Document all readings and responses.</li> </ol>

		<p><b>Review:</b></p> <p>Submit to the <i>Pohnpei Utilities Corporation</i> for its acceptance and update.</p> <p><b>ACCEPTANCE CRITERIA</b></p> <p>All protection functions are fully operational and operate to required levels within the relay <i>OEM</i> allowable tolerances. Measuring instrumentation used shall be sufficiently accurate and calibrated to a traceable standard.</p> <p>Submit a report to the <i>Pohnpei Utilities Corporation</i> one month after test.</p>
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### 19.3.2 - Renewable Power Plants active power control capability verification

Parameter	Reference	Description
Active power control function and operational range	Section 10 depending on Type	<p><b>APPLICABILITY</b></p> <p>All new <i>Renewable Power Plants</i> coming on line and after major modifications or refurbishment of related plant components or functionality.</p> <p><b>Routine test/reviews:</b> Confirm compliance every 6 years.</p> <p><b>PURPOSE</b></p> <p>To confirm that the active power control capability specified is met.</p> <p><b>PROCEDURE</b></p> <p>The following tests shall be performed within an active power level range of at least 0.2p.u.or higher</p> <ol style="list-style-type: none"> <li>1. The <i>plant</i> will be required to regulate the active power to a set of specific setpoints within the design margins.</li> <li>2. The <i>plant</i> will be required to obtain a set of active power setpoints within the design margins with minimum two different gradients for ramping up and two different gradients for ramping down.</li> <li>3. The <i>plant</i> will be required to maintain as a minimum two different set levels of spinning reserve within the design margins.</li> <li>4. The <i>plant</i> will be required to operate as a minimum to limit active power output according to two different absolute power constraint set levels within the design margins.</li> <li>5. The <i>plant</i> will be required to verify operation according to as a minimum two different parameter sets for a frequency response curve within the design margins.</li> </ol> <p><b>ACCEPTANCE CRITERIA</b></p>

	<ol style="list-style-type: none"><li>1. The <i>plant</i> shall maintain the set output level within <math>\pm 2\%</math> of the capability registered with the <i>Pohnpei Utilities Corporation</i> for at least one hour.</li><li>2. The <i>plant</i> shall demonstrate ramp rates with precision within <math>\pm 2\%</math> of the capability registered with the <i>Pohnpei Utilities Corporation</i> for ramp up and down.</li><li>3. The <i>plant</i> shall maintain a spinning reserve set level within <math>\pm 2\%</math> of the capability registered with the <i>Pohnpei Utilities Corporation</i> for at least one hour.</li><li>4. The <i>plant</i> shall maintain an absolute power constraint set level within <math>\pm 2\%</math> of the capability registered with the <i>Pohnpei Utilities Corporation</i> for at least one hour.</li><li>5. The <i>plant</i> shall demonstrate that the requested frequency response curves can be obtained.</li></ol> <p>Submit a report to the <i>Pohnpei Utilities Corporation</i> one month after the test.</p>
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### 19.3.3 Renewable Power Plants reactive power control capability verification

Parameter	Reference	Description
Reactive power control function and operational range	Sections 6 and 7 depending on Type	<p><b>APPLICABILITY</b></p> <p>All new <i>Renewable Power Plants</i> coming on line and after major modifications or refurbishment of related plant components or functionality.</p> <p><b>Routine test/reviews:</b> Confirm compliance every 6 years.</p> <p><b>PURPOSE</b></p> <p>To confirm that the reactive power control capability specified is met.</p> <p><b>PROCEDURE</b></p> <p>The following tests shall be performed within a minimum active power level range of at least 0.2 p.u. or higher</p> <ol style="list-style-type: none"> <li>1. The <i>plant</i> will be required to regulate the voltage at the point of connection to the grid to a set level within the design margins.</li> <li>2. The <i>plant</i> will be required to provide a fixed Q to a set level within the design margins.</li> <li>3. The <i>plant</i> will be required to obtain a fixed PF within the design margins.</li> </ol> <p><b>ACCEPTANCE CRITERIA</b></p> <ol style="list-style-type: none"> <li>1. The <i>plant</i> shall maintain the set voltage within <math>\pm 5\%</math> of the capability registered with the <i>Pohnpei Utilities Cooperation</i> for at least one hour.</li> <li>2. The <i>plant</i> shall maintain the set Q within <math>\pm 2\%</math> of the capability registered with the <i>Pohnpei Utilities Cooperation</i> for at least one hour.</li> <li>3. The <i>plant</i> shall maintain the set PF within <math>\pm 2\%</math> of the capability registered with the <i>Pohnpei Utilities Cooperation</i> for at least one hour.</li> </ol>

		Submit a report to the <i>Pohnpei Utilities Corporation</i> one month after the test.
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#### 19.3.4 Renewable Power Plants power quality calculations

Parameter	Reference	Description
Power quality calculations for:	Section 8 depending on Type	<p><b>APPLICABILITY</b></p> <p>All new <i>plants</i> coming on line and after major modifications or refurbishment of related plant components or functionality.</p> <p><b>Routine test/reviews:</b> Confirm compliance every 6 years.</p> <p><b>PURPOSE</b></p> <p>To confirm that the limits for all power quality parameters specified is met.</p> <p><b>PROCEDURE</b></p> <p>The following tests shall be calculated within a minimum active power level range from 0.2p.u. to 1.0p.u.</p>
1. Rapid voltage changes		1. Calculate the levels for rapid voltage changes are within the limits specified over the full operational range.
2. Flicker		2. Calculate the flicker levels are within the limits specified over the full operational range.
3. Harmonics		3. Calculate the harmonics are within the limits specified over the full operational range.
4. Inter-harmonics		4. Calculate the interharmonics are within the limits specified over the full operational range.

5. High frequency disturbances		<p>5. Calculate the disturbances higher than 2 Hz are within the limits specified over the full operational range.</p> <p><b>ACCEPTANCE CRITERIA</b></p> <ol style="list-style-type: none"> <li>1. The calculations shall demonstrate that the levels for rapid voltage changes are within the limits specified over the full operational range.</li> <li>2. The calculations shall demonstrate that the flicker levels are within the limits specified over the full operational range.</li> <li>3. The calculations shall demonstrate that the harmonics are within the limits specified over the full operational range.</li> <li>4. The calculations shall demonstrate that the interharmonics are within the limits specified over the full operational range.</li> <li>5. The calculations shall demonstrate that the disturbances higher than 2 Hz are within the limits specified over the full operational range</li> </ol> <p>Submit a report to the <i>Pohnpei Utilities Corporation</i> one month after the test.</p>
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### 19.3.5 Renewable Power Plants fault ride through simulations

Parameter	Reference	Description
Simulations of fault ride through voltage droops and peaks.	Section 4	<p><b>APPLICABILITY</b></p> <p>All new <i>plants</i> coming on line and after major modifications or refurbishment of related plant components or functionality.</p> <p><b>Routine test/reviews:</b> None.</p> <p><b>PURPOSE</b></p> <p>To confirm that the limits for all power quality parameters specified is met.</p> <p><b>PROCEDURE</b></p> <p>By applying the electrical simulation model for the entire <i>plant</i> it shall be demonstrated that the <i>plant</i> performs to the specifications.</p> <ol style="list-style-type: none"> <li>1. Area A - the <i>plant</i> shall stay connected to the network and uphold normal production.</li> <li>2. Area B - the <i>plant</i> shall stay connected to the network. The <i>plant</i> shall provide maximum voltage support by supplying a controlled amount of reactive power within the design framework offered by the technology, see Figure 1.</li> <li>3. Area C - the <i>plant</i> is allowed to disconnect.</li> <li>4. Area D - the <i>plant</i> shall stay connected. The <i>plant</i> shall provide maximum voltage support by absorbing a controlled amount of reactive power within the design framework offered by the technology, see Figure 1.</li> </ol> <p><b>ACCEPTANCE CRITERIA</b></p> <ol style="list-style-type: none"> <li>1. The dynamic simulations shall demonstrate that the <i>plants</i> fulfils the requirements specified.</li> </ol> <p>Submit a report to the <i>Pohnpei Utilities Corporation</i> three month after the commission.</p>



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## Appendix 2: Description of GDAT model



Ricardo  
Energy & Environment



# **Description of Measurement of Real-time Dispatch Performance Program**

**June 2018**

**Document Status****Title: Description of Generation Dispatch  
Analysis Tool for Pacific Islands****Reference:****Issue:** Version 1.0**Date:** 26 June 2018**Electronic Doc Ref:** Description of GDAT model v1.0.pdf

Approved by

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**History**

<b>Issue</b>	<b>Date</b>	<b>Author</b>	<b>Description</b>
Ver 1.0	06 June 18	Graeme Chown, Grant Grobbelaar and Jason Miskin	Pacific Island model description

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<b>Name of Client</b>	<b>Pacific Power Association</b>
<b>Assignment Name:</b>	Assessment of Variable Renewable Energy (VRE) Grid Integration, and Evaluation of SCADA and EMS system design in the Pacific Island Counties

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## Executive Summary

This document contains the description of the Generation Dispatch Analysis Tool which is designed to simulate frequency control over a typical day / week, analyse various scenarios including wind, solar power and storage, evaluate different control strategies, determine spinning reserve requirements and audit system dispatch.

For the Pacific islands the model is developed specifically test the impact of increasing wind and solar. Mitigation strategies to control frequencies using battery power firstly to improve frequency control and secondly to act as a storage.

This document provides the details of the program and how to run simulation studies.

## 1 Introduction

The Generation Dispatch Analysis Tool (GDAT) is a product in MATLAB® & Simulink® that has been developed by Dr Graeme Chown with assistance from Optimum Solutions.

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
6. System Operator dispatch audit

The key features of the tool are:

1. Easy interface to input data
2. Automatic generation of code for the options chosen in the input data
3. Automatic saving of results
4. Graphical user interface to view results
5. Automatic generation of key performance statistics

This document is a description of the main features of the GDAT model, how to input data, run simulations and view results.

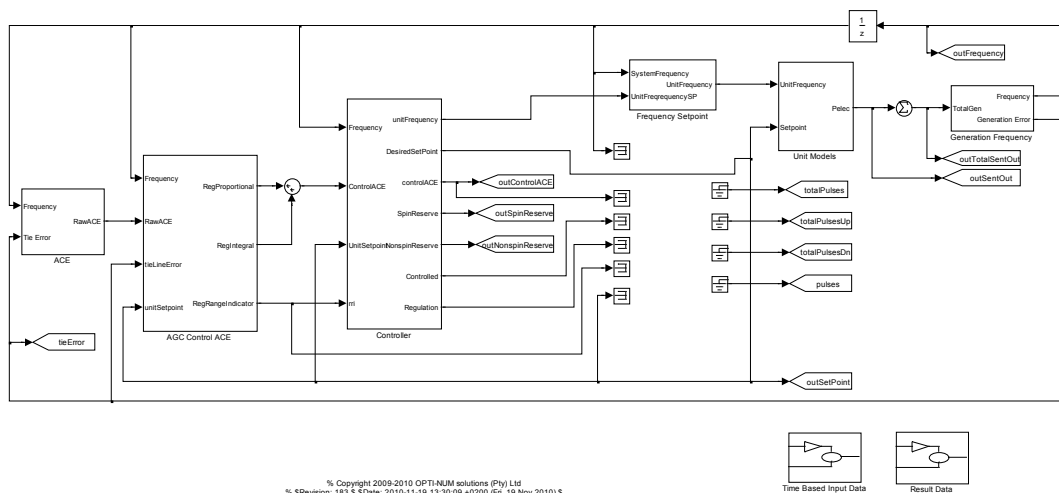
## 2 Description of GDAT model components

### 2.1 Overview of model components

Figure B1 shows the AGC model as built using MATLAB and Simulink. As shown, the model is made up of six different blocks (or modules), and each block is further made up of additional blocks and/or subroutines also built using MATLAB and Simulink. The following are the main modules of the MATLAB AGC model:

- ACE (Area Control Error): This is the first module and calculates the raw ACE. The ACE is calculated from the frequency difference between target and actual frequencies.

- **Controller:** This module calculates the amount of control needed. Considering the financial components, the module calculates the desired generation for all the units under AGC control.
- **Frequency Setpoint:** This module determines which units are on governing and should receive the actual system frequency; otherwise frequency is set to nominal for units not on governing.
- **Unit Models:** This module contains the models for all the units and produces the electrical power output for each unit.
- **Generation Frequency:** This module receives the sum of all the electrical power outputs from all the generating units to give the total generation. The Generation Frequency module compares the actual generation to the demand and then generates the frequency.



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% \$Revision: 183 \$ \$Date: 2010-11-19 13:30:09 +0200 (Fri, 19 Nov 2010) \$

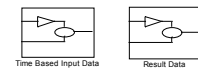


Figure B1: MATLAB AGC Model.

Two additional modules can be seen, viz. Time Based Input Data and Result Data. The Time Based Input Data is where the time based data is developed for use in the model. The Result Data is where the results are stored for later use, e.g. plotting.

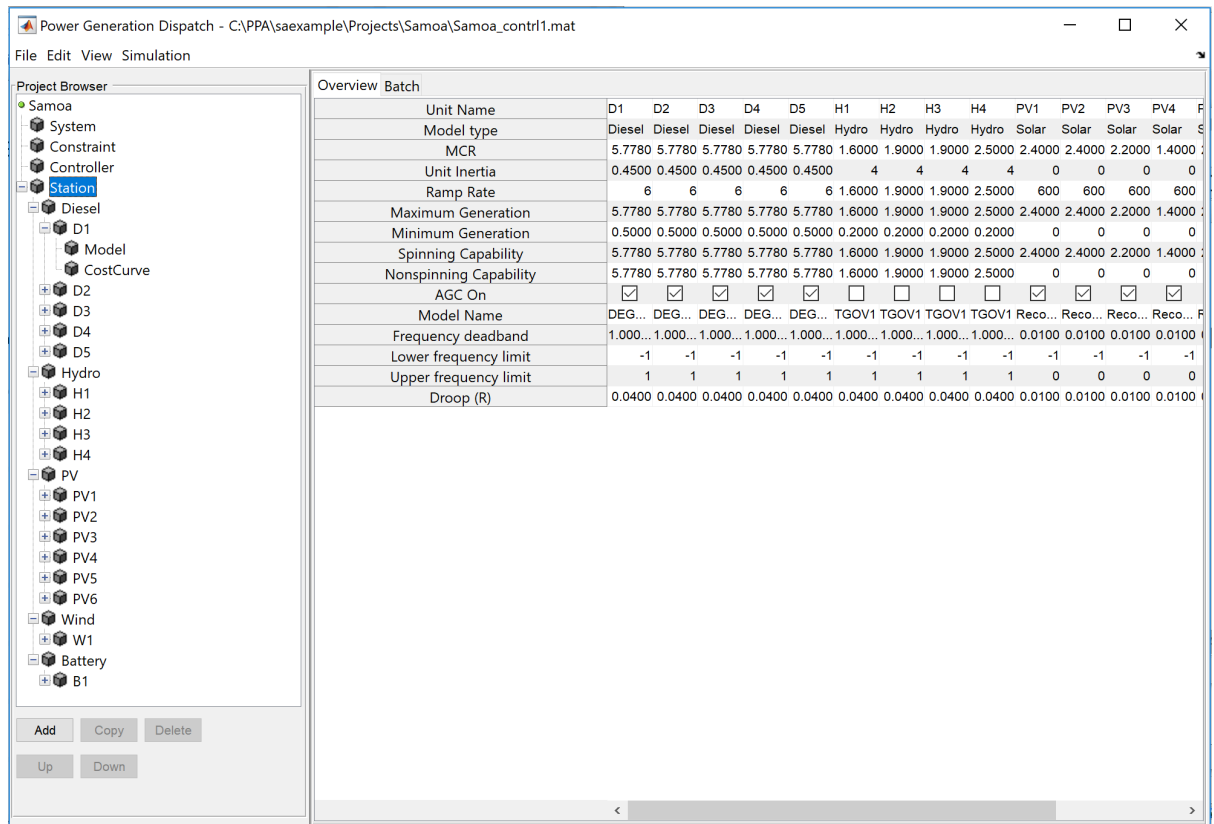
The details of each module are further described in the sections to follow. In addition, a description of the model's entry point is described – the Power Generation Model Graphical User Interface (GUI).

### 2.1.1 GDAT Model Input Data

Figure B2 shows the GDAT Graphical User Interface – the entry point of the MATLAB GDAT Model. All the information required for the studies is entered via this Graphical User Interface, i.e. external data files, generating

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units and their associated dynamic models and cost curves, AGC parameters, etc.



Unit Name	D1	D2	D3	D4	D5	H1	H2	H3	H4	PV1	PV2	PV3	PV4	PV5
Model type	Diesel	Diesel	Diesel	Diesel	Diesel	Hydro	Hydro	Hydro	Hydro	Solar	Solar	Solar	Solar	Solar
MCR	5.7780	5.7780	5.7780	5.7780	5.7780	1.6000	1.9000	1.9000	2.5000	2.4000	2.4000	2.2000	1.4000	1.4000
Unit Inertia	0.4500	0.4500	0.4500	0.4500	0.4500	4	4	4	4	0	0	0	0	0
Ramp Rate	6	6	6	6	6	1.6000	1.9000	1.9000	2.5000	600	600	600	600	600
Maximum Generation	5.7780	5.7780	5.7780	5.7780	5.7780	1.6000	1.9000	1.9000	2.5000	2.4000	2.4000	2.2000	1.4000	1.4000
Minimum Generation	0.5000	0.5000	0.5000	0.5000	0.5000	0.2000	0.2000	0.2000	0.2000	0	0	0	0	0
Spinning Capability	5.7780	5.7780	5.7780	5.7780	5.7780	1.6000	1.9000	1.9000	2.5000	2.4000	2.4000	2.2000	1.4000	1.4000
Nonspinning Capability	5.7780	5.7780	5.7780	5.7780	5.7780	1.6000	1.9000	1.9000	2.5000	0	0	0	0	0
AGC On	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>
Model Name	DEG...	DEG...	DEG...	DEG...	DEG...	TGOV1	TGOV1	TGOV1	TGOV1	Reco...	Reco...	Reco...	Reco...	Reco...
Frequency deadband	1.000...	1.000...	1.000...	1.000...	1.000...	1.000...	1.000...	1.000...	1.000...	0.0100	0.0100	0.0100	0.0100	0.0100
Lower frequency limit	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Upper frequency limit	1	1	1	1	1	1	1	1	1	1	0	0	0	0
Droop (R)	0.0400	0.0400	0.0400	0.0400	0.0400	0.0400	0.0400	0.0400	0.0400	0.0100	0.0100	0.0100	0.0100	0.0100

Figure B2: GDAT Model Input Data GUI.

### 2.1.2 GDAT Model Output (Plotting)

Figure B3 show the GDAT Simulation Results plotter which allows the user to plot simulation results. The interface allows for the plotting of important variables for analysis, viz. electrical power outputs of generating units, system frequency and other variables, e.g. ControlACE, SpinReserve, TotalGen, etc.

Figure B3: GDAT Simulation Results Plotter.

Figure B4 shows, for example, a plot of the Actual Sent Out (MW) for all the units modelled. Figure B5 shows Simulated Frequency (HZ) and Actual Frequency (Hz) plots.

The GDAT Simulation Results interface also has a “Tabulate” button (top right corner) which can be used to automatically generate Excel spreadsheets that compare variables based on the actual and simulated values. For example,

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the Excel spreadsheet calculates the cost of the original dispatch and shows the difference between the actual dispatch costs and the simulated dispatch costs. This difference is on an hourly and totals basis to enable easy identification of the difference between simulated and actual results. Figure B6 shows an example of the Excel spreadsheet.

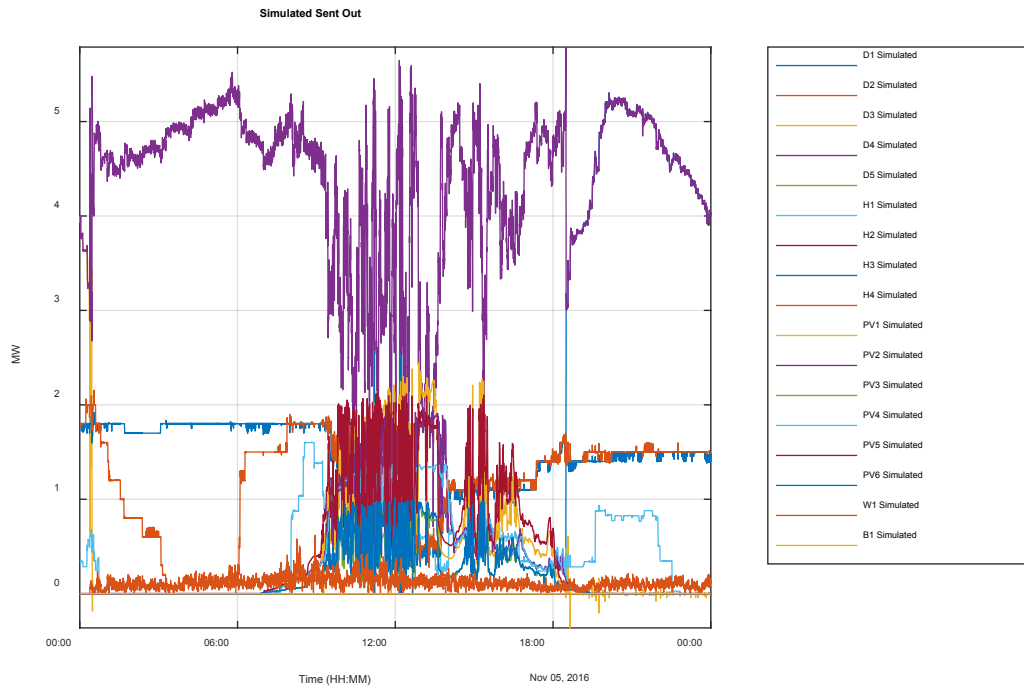


Figure B4: Simulated Sent Out (MW) Plot.

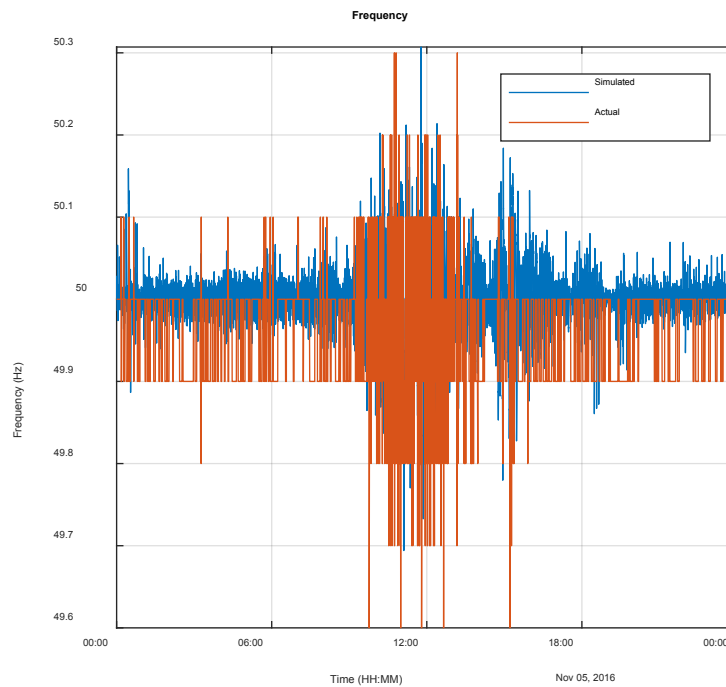


Figure B5: Simulated Frequency (blue) vs. Actual Frequency (orange) Plot.

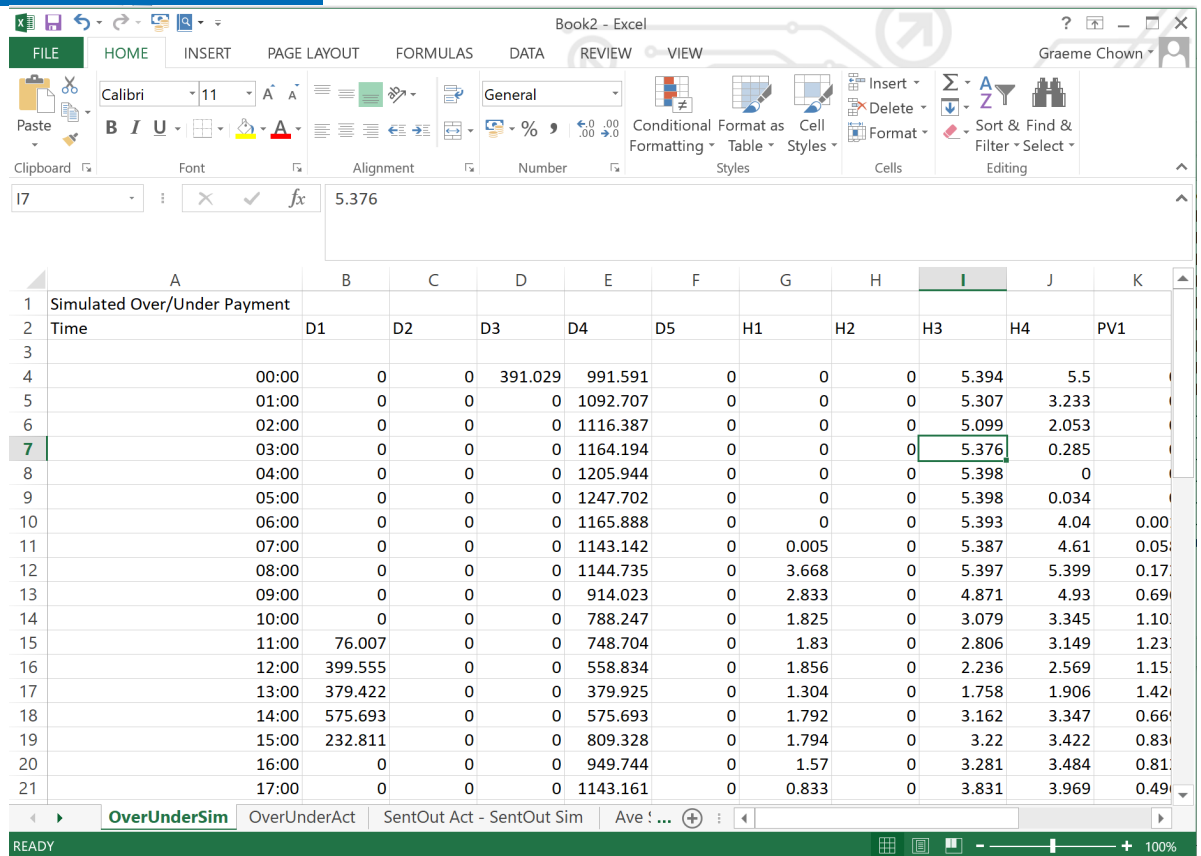


Figure B6: Excel Spreadsheet Example.

### 2.1.3 GDAT Model: ACE and Financial Controller

This section provides details of the following MATLAB GDAT model: ACE and Financial Controller.

Figure B7 shows a picture of the ACE module which calculates the raw ACE. The raw ACE is the calculation of the MW shortfall or surplus and is used in the Controller to determine the amount of MWs required to control the frequency. The bias used for raw ACE calculation is 10% of the maximum demand per 1 Hz frequency change, this is the international standard for the bias.

The model has the capability to be a part of an interconnection but this is not used for Pacific Islands – this is set by interconnect on/off flag set to false.

The raw ACE is fed into a PID (proportional-integral-derivative) controller (Financial Controller module) and the output of the controller is the control ACE (Figure B1).

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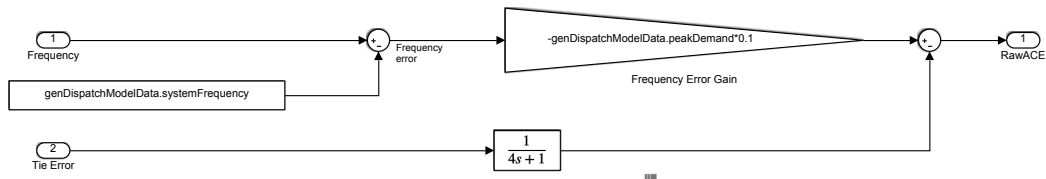


Figure B7: ACE Module.

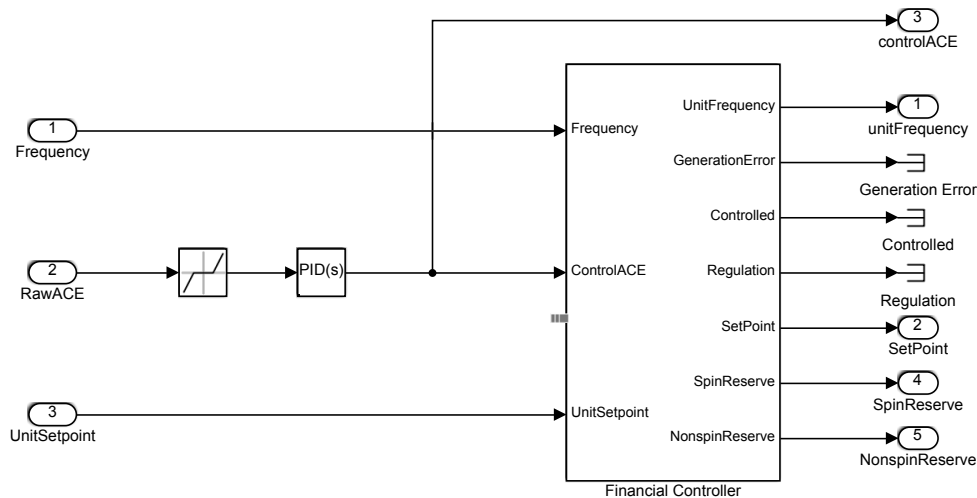


Figure B8: Controller Module.

The Controller (Figure B8) is designed to control the frequency at nominal (50 or 60Hz) by determining a new desired set point for generating units on AGC based on the Financial Controller routine. If the frequency is below nominal the controller will increase unit setpoints and visa-versa if the frequency is higher than nominal the controller will reduce unit setpoints.

The inputs to the Financial Controller (Figure B9) are as follows:

1. Frequency,
2. Control ACE which is from the output of the PID controller,

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3. Current MW output (or where the unit is currently),
4. Maximum and minimum MW which determines the range where the unit can be controlled,
5. Unit ramp rate determines how much the unit can move for the period,
6. Unit spin and non spin capability which is the maximum MWs that can be allocated to spinning and non spinning reserve for each unit,
7. Unit AGC on/off which determines whether the unit can be controlled or not,
8. Elbow and price which determines the cost for the unit, and
9. Previous set-point which is where the current unit was controlled on the previous cycle.

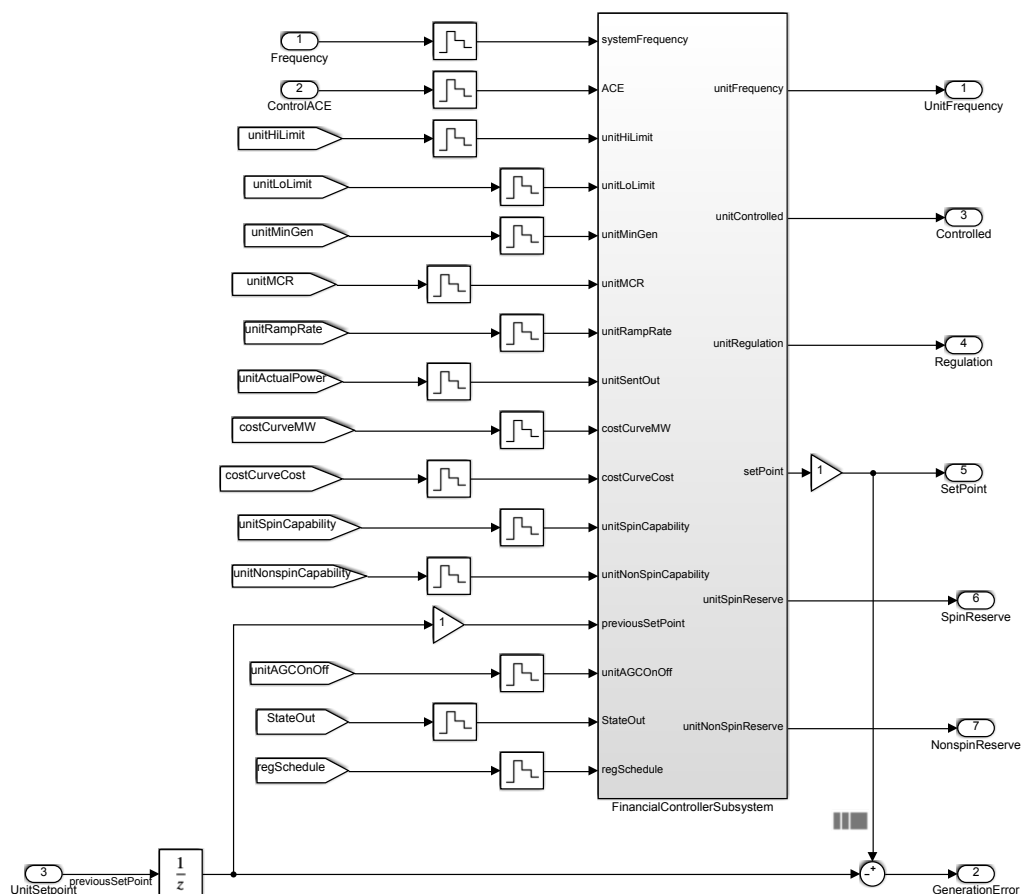


Figure B9: Financial Controller.

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The financial controller dynamically calculates the system inertia. A unit is online if it is  $>$  min generation limit of the unit. Inertia of each unit is an input parameter into the model. A factor of 0.2 is added to the system inertia to account for induction motors in the system which also contribute to the system inertia.

The units are broken into three categories in the financial controller to ensure best economic dispatch:

- Wind and Solar
- Storage
- Non renewable

The financial controller has two control options, namely controller 1 and controller 2.

Controller 1 set by parameter `agcControllerType = 1` in GUI

Controller 1 dispatches all units under AGC at an equal level. This controller is designed to reflect the current Pacific Islands practice of operating units in a group at the same dispatch level. This philosophy maximises security as it keeps an equal percentage level of spinning reserve on each unit.

The controller has the following other features:

1. Dynamic spinning reserve requirement calculated as the minimum spinning reserve requirement plus 30% of renewable power being produced, to ensure sufficient spinning reserve to cater for momentary dips in wind and solar units
2. Reducing wind and solar units if their output is higher than the technical capability of the existing synchronised units. This is calculated as required generation (current plus ACE)  $>$  renewable current power maximum output + synchronised units minimum generation level.
3. Pre-allocation to increase wind and solar units below their maximum capacity as determined a dynamic high limit capability limit sent by the wind and solar units and if there is room to move non-renewable units down
4. Charging of battery units set on AGC up to 95% if there is surplus wind and solar units generation. There is a high limit from when charge is 90% = -100% minimum setpoint proportionally down to a charge of

95% == 0% minimum setpoint. This allows 5% for primary frequency control high frequency incidents.

5. Discharging of battery units on AGC down to 20% before utilising diesel units. There is a high limit from when charge is 25% = 100% maximum setpoint proportionally down to a charge of 20% == 0% maximum setpoint. This allows 10% for primary frequency control low frequency incidents as the battery can only be discharged to 10%.
6. Keep primary frequency control only batteries (that is AGC off) above 50% charge by charging them at 5% of high limit
7. Switch off non-renewable and AGC on units if spinning reserve is double the requirement. The remaining non-renewable units must also be able to provide spinning reserve.
8. Switch on non-renewable and AGC on units if spinning reserve drops below target level.
9. A new setpoint is derived for non-renewable and AGC on units based on ACE plus current generation. The setpoint is apportioned proportionally to each units MCR. The amount the setpoint can change is then limited to the unit ramp rate.

Controller 2 set by parameter `agcControllerType = 2` in GUI

Controller 2 derives a new setpoint for all units that are on AGC using MATLAB's `optimiseCost` function.

The following additional feature are put into the `optimise` function:

1. Spinning reserve requirement
2. Unit high and low limit
3. Unit cost as derived from the cost curve

#### 2.1.4 GDAT Model: Unit Models

The Unit Models module contains all the governor models of all the generating units considered for the studies. The model parameters are in per unit and as a result each MW Demand is divided by the maximum continuous rating to obtain a per unit input into the models (Figure B10). Similarly the frequency is divided by 50.

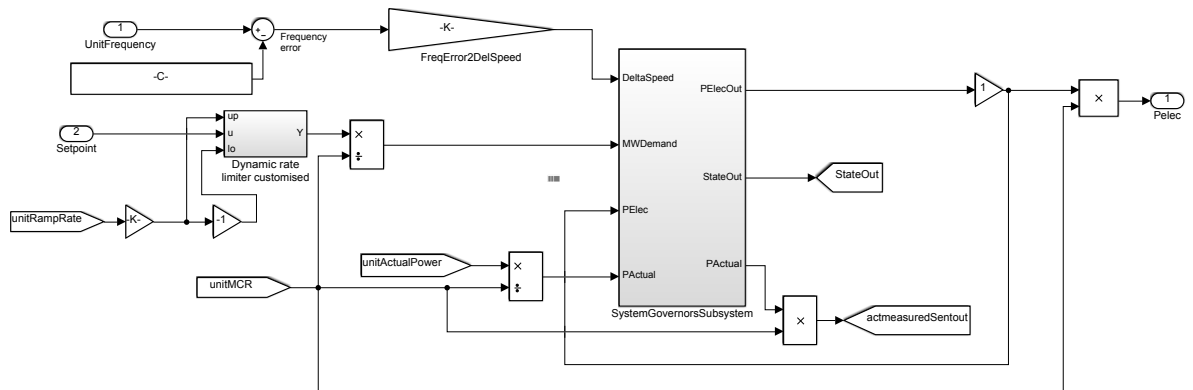


Figure B10: Unit Models Module.

Figure B11 shows the aggregated system governor models. Based on Figure B11 the study considers five kinds of governor models, three of which are standard models, namely DGOV1, HYG0V1 and TGOV1. Two additional models were created to represent wind and solar units (Figure B12) and batteries (Figure B13) respectively.

The recorded data model is used for the replaying nominal of the wind and solar recorded multiplied by wind or solar farm size. This does allow for scaling of the wind and solar unit by just adjusting the MCR. The model also has the facility to time shift the wind and solar data using parameter Time Shift. The recorded data the delta speed / frequency coming into the model and the primary frequency response can be set-up. Typically this will be a reduction in the output for frequencies greater than 0.5 Hz from nominal. The setpoint comes from the financial controller and this is limited to the level recorded on the day.

The battery model has the same primary frequency response and setpoint features as the recorded data. The battery has a charge recorder and the state of the charge is outputted as state. The state of charge is used in the financial controller to determine whether the battery can be charged / discharged. If the battery is fully charged the setpoint in is limited to zero and the same for when fully discharged.

DGOV1 controller has been simplified by removing the two lead lag controllers (PID) (shaded in Figure B14) and making this a simple PI controller. None of the diesel power stations logics and parameters provided had the differential activated so this is consistent with the diesel units performance.



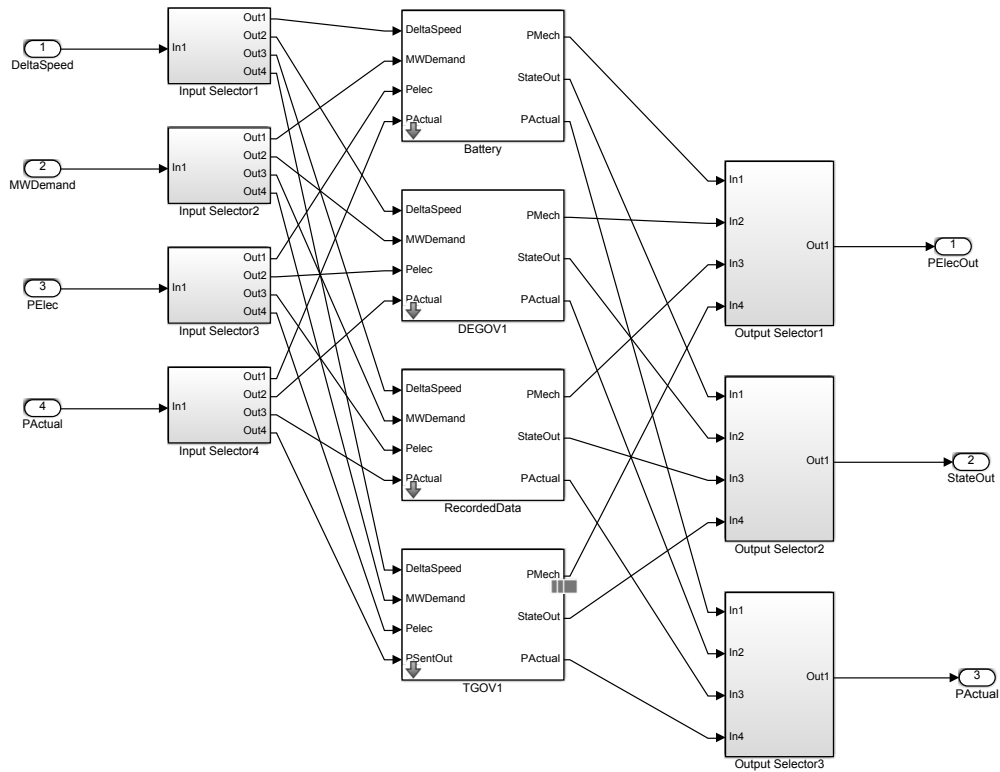


Figure B11: Aggregated System Governor Models.

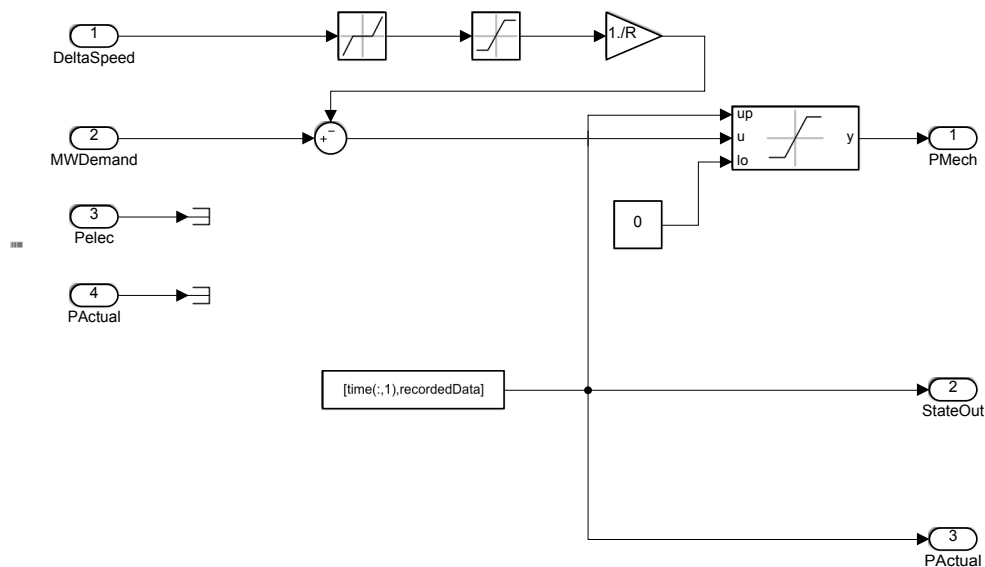


Figure B12: Recorded Data – used for Wind and Solar model.

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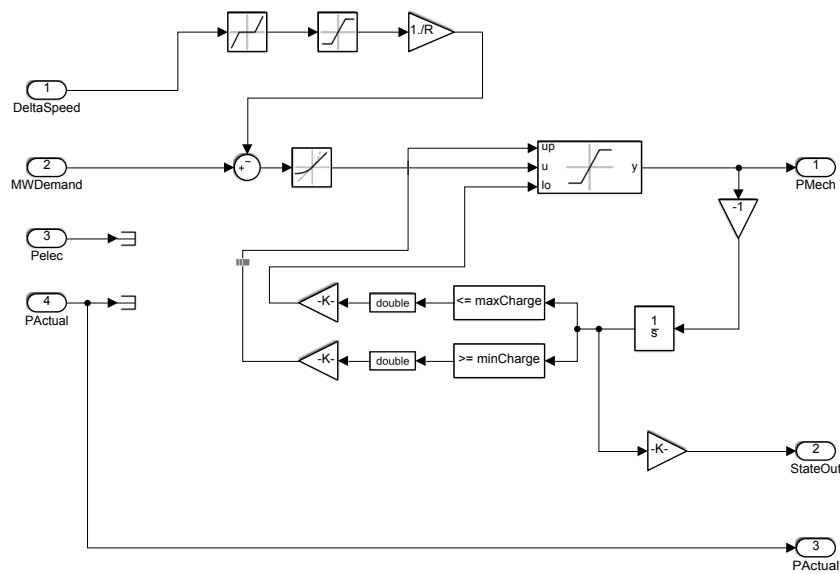


Figure B13: Battery Model.

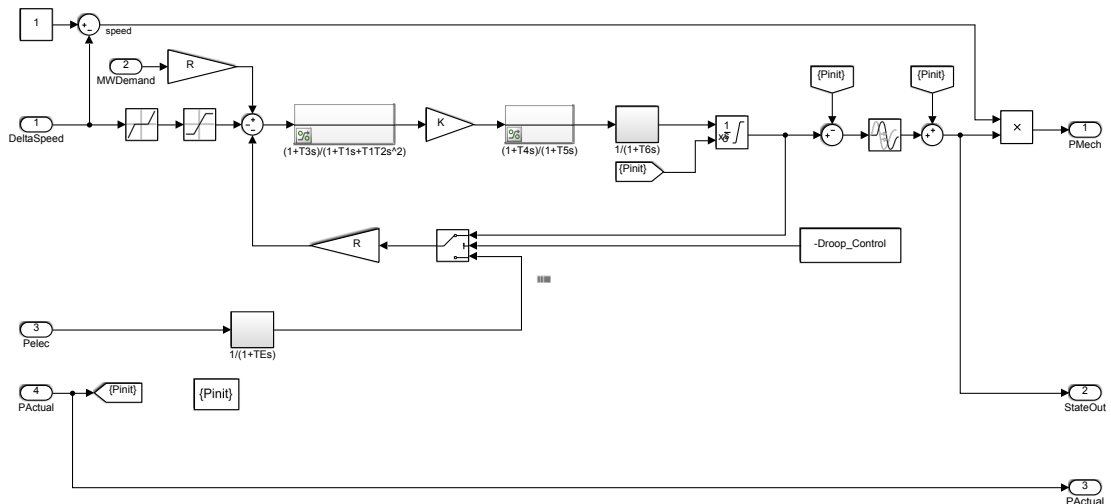


Figure B14 DGOV1 controller with lead lag (PID) controllers deactivated

### 2.1.5 GDAT Model: Generation Frequency Module

The total load is calculated to be the total generation that was recorded by the SCADA system plus load frequency support when the frequency was not at nominal 50 Hz – Figure B15. The difference between the simulated generation and load determines the new frequency. The simulated frequency error is a function of the network inertia which is dynamically calculated by the units online (see financial controller) and the load frequency support. The

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frequency error is added to nominal 50 Hz to give the final simulated frequency.

The model is further adapted to be able to operate in an interconnected system and calculate tie line error and interconnection frequency.

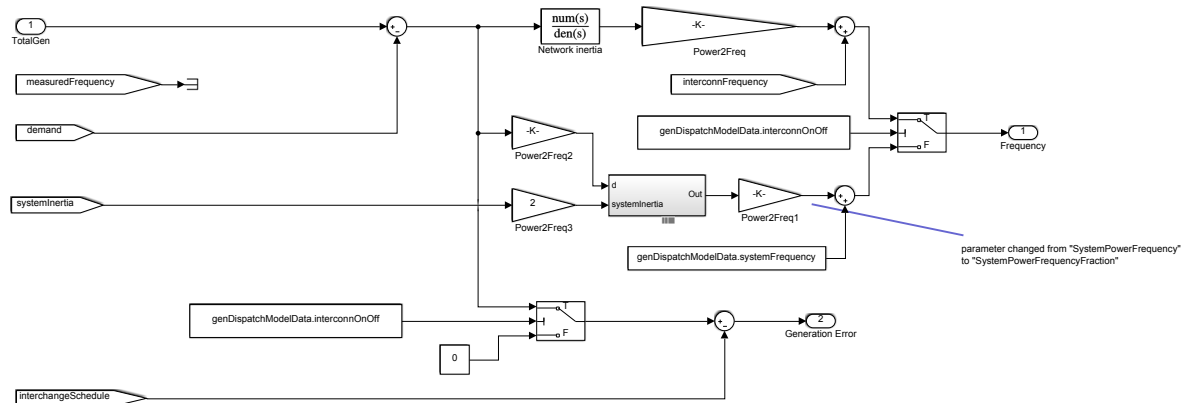


Figure B15: Generation Frequency Model.

## Appendix 3: Description of SCADA and EMS

# **Description of SCADA and Energy Management System (EMS)**

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## 1.1 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 a 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.

## 1.2 SCADA Systems Basic activity

As indicated into the acronym of SCADA, **S**ystem **C**ontrol and **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.

### 1.2.1 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 ( $\pm 0 - 2000$ ), transmitted in digital format and, at reception are transformed to engineering

values (Volts, Amperes etc.). 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 are collected and sent to the Control Centre as 0 or 1. These values represents either the status of a breaker or an isolator or if an alarm is 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, prepares it to communicate and transfer it to the control center when it is triggered to do so.

This communication is demanded by the control center, which is normally done on a timely basis (scan). In case of alarms, the RTU may initiate the communication with the control center, requesting to establish a communication and to be interrogated.

Size and capacity of an RTU can be adjusted to the needs, from a simple RTU to collect one value to an RTU to collect and operated a big substation, using in each case the appropriate technology. Even Programmable Logic Controller (PLC<sup>1</sup>) have been used in small systems.

### 1.2.2 Communications Management

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

Communications technologies used for transmission of a big amount of information in a wide area can be based on wired or wireless solutions. The wired solution varies 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 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 creates a dependency that the supplier of the RTU that should be the same (or compatible) with the SCADA system. This could be avoided by ensuring that an RTU supplier emulates the SCADA protocol with the information that is provided by the supplier. This situation is changing but some of those protocols are still in service due to long usable life of RTUs.
- 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

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<sup>1</sup> PLC acronym is used also as Power Line Carrier, a communication technology that uses the electric wires as communications carrier.



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, which allows a multi-vendor option for systems and elements.
- d. The Internet Protocol (IP) is the principal communications protocol used to establish Internet, which uses source and destination addresses. Its routing function enables internetworking and is useful for connecting the RTUs 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.

### 1.2.3 Information validation

The analogue information ( $\pm 0 - 1$  mA as example) is converted and sent to the control centre in counts  $\pm 0 - 2000$  (for example, 0 mA = 0 counts and 1 mA 1.900 counts). The first activity in the Control Centre converts the counts into engineering units and computes 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 within 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.

### 1.2.4 Alarms subsystem

The alarms are one simplified way to alert operators to some irregularities in the system. This helps to the operator to concentrate on 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.

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#### **Pacific Power Association**

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

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.

#### 1.2.5 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.

Databases can be presented to the operator in form of tabular or full graphics. The 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.

#### 1.2.6 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 an efficient control of the network conditions.

### 1.2.7 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.

Communications  
Management

Basic  
SCADA  
Functionality

Network Control

## 1.3 Added applications

SCADA has been used to control electricity systems. SCADA systems were first implemented in the transmission systems and were commercially available in the late 60's and early 70's. For the electricity system, SCADA very soon became the most effective control tool to improve system information and control and, at the same time, reduce operative costs.

For these reasons, around the world, SCADA applications have been developed and they form an important part 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.

## 1.4 EMS versus DMS

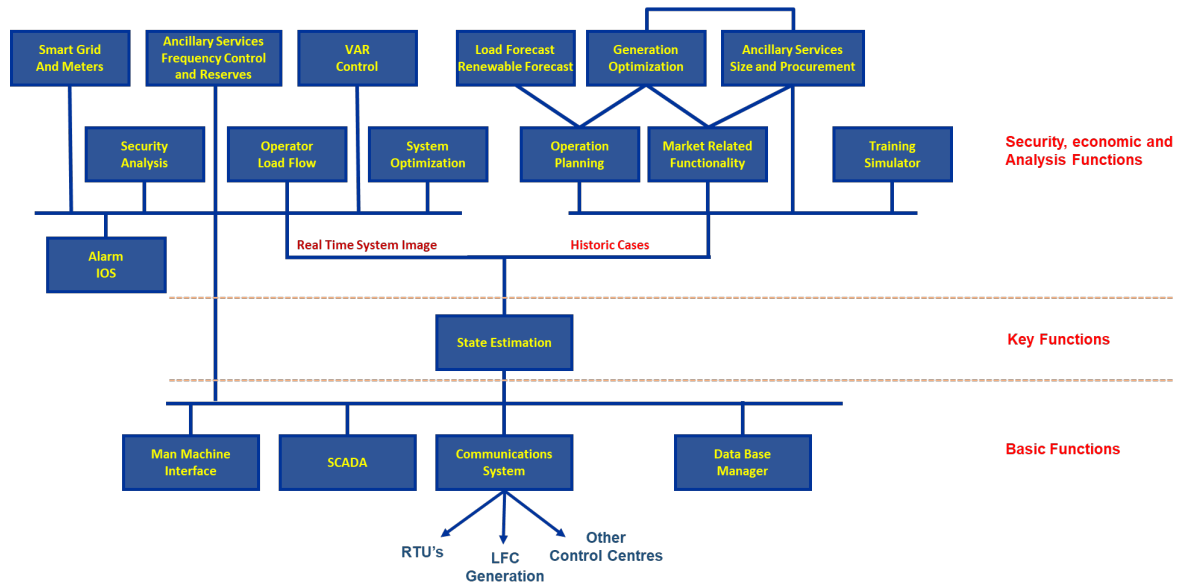
There are two main suites of external applications that group the main functionalities design, according to different objectives of the network to be controlled like generators control, transmission systems or distribution systems:

- 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 through zero voltage.

### 1.4.1 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.

**Figure Error! No text of specified style in document.-1: EMS functionalities supported by the SCADA System**



Briefly, the following applications are oriented to:

#### 1.4.1.1 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 that any value in the system would have some element of error. For example, the voltage measurements show that voltage at a node is 220 kV, which means that the value sent to the control centre is 220 kV, but the real value could be any value between 198 and 222 kV. The same error is expected in other readings that are obtained for power and current measurements.

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.

#### 1.4.1.2 Load Flow

Once the state estimator is well tuned and available, then its solution could be used as input for the load flow studies. It is possible to run the load flow, based on information available in the network model and the information available for the generation and load connected to each node. The model calculates the real voltages and flows on each node or network element at real time or in study mode. In addition to this, the load flow will simulate any new situation, which could have modified generation or load profiles or the network topology. This load flow study results, based on simulations, would show the system conditions such as voltage and power flows.

#### 1.4.1.3 Optimal Load Flow.

In this case, the inputs are the same as in above but in addition, the results will show the optimal values for some control elements values such as reactive generation, shunt devices or tap changes. It could be proposed that these devices are changed, after evaluating the need for change in control and considering the cost of changing the asset. On similar lines, system losses will also have a cost. The control function will display the cost of an optimal set of control elements and the motive would be to reduce losses with a minimum cost. The use of different costs for each action will reflect the system control priorities.

#### 1.4.1.4 Ancillary Services requirements

Two of the most important aspects of system security are:

- The **Load Frequency Control (LFC)**, is the application in the system that controls directly the governors of the dedicated generating units in an automated closed loop. The application increases or reduces the actual generation to maintain the frequency stability. The LFC sends a signal to raise/lower or fix a set point and this is also known as Automated Generation Control (AGC).
- **Voltage control**, especially with the integration of renewable generation parks has become an important requirement to maintain the power quality. In many parts of the world, the new renewable generation plants have had limited contribution to voltage stability as compared to the conventional units. The voltage control could be achieved by use of modern tools such as shunt devices, VAR systems, SVC and STATCOM units.

#### 1.4.1.5 Security Analysis

The security analysis applications are 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), which has all the conditions included in the security criteria and these are tested during operation planning and in real-time.

These suite of functions are basic to determine the capability of the system to survive to any contingency included in the security criteria established in the grid codes or in the regulation laws.

#### *1.4.1.6 Forecast Applications*

Load demand forecast and Renewable Generation forecasts applications normally provide forecasts at park level for wind and solar generation. The forecast is done for longer term, which is used for planning and at a year-to-year level to guarantee the availability of resources.

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.

#### *1.4.1.7 Generation schedule*

Using the load and RE forecasts as inputs, the generation schedule be developed. In the generation schedule, the generation needs are estimated for the day ahead or in Real Time for the near future. The schedule also verifies the needs for controls and the availability on the system for different types of reserves, according to the security constraints.

#### *1.4.1.8 Generation Control*

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

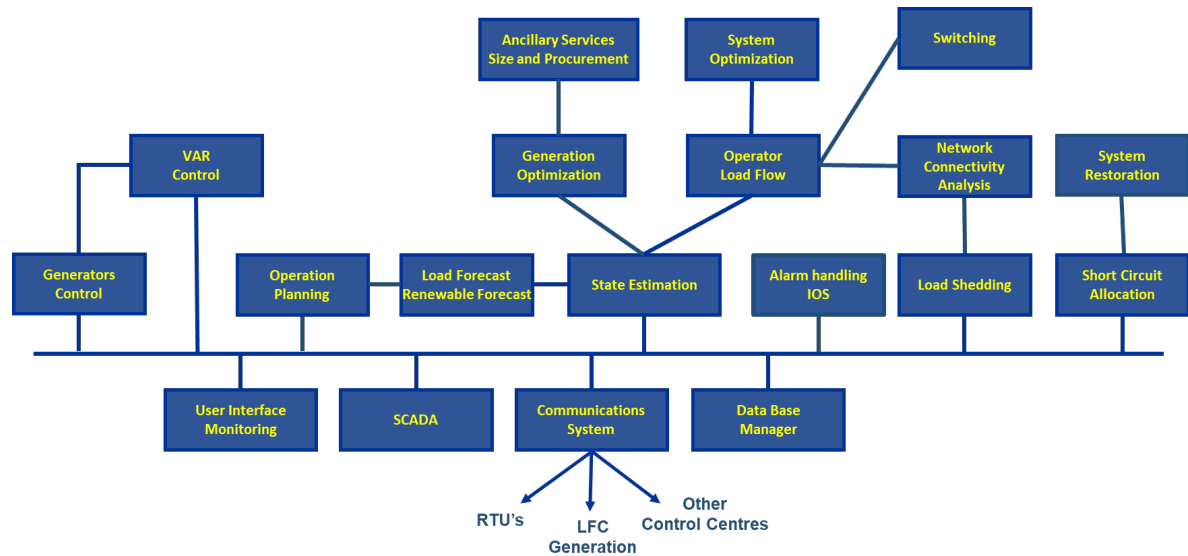
This control philosophy is extended to most large power plants from Nuclear Plants to Coal, Gas or hydro units. It is not a simple application. To control a unit or a power plant, a group of applications are run in a coordinated mode and these allow operators to control a variety of assets, from the high voltage park to any kind of fuel based plants. Those applications facilitate the control of many generating units, which are controlled from a centre located outside of the plant itself, reducing the operating costs considerably.

### 1.4.2 Distribution Management System (DMS) System

The Distribution Management System is more oriented to manage distribution networks. For radial networks, the applications are completely different than those for the meshed networks.

The functionality of applications are similar than in case of Energy Management System (EMS) but the methodology and mathematical approach are quite different.

**Figure Error! No text of specified style in document.-2: Functionality of DMS applications**

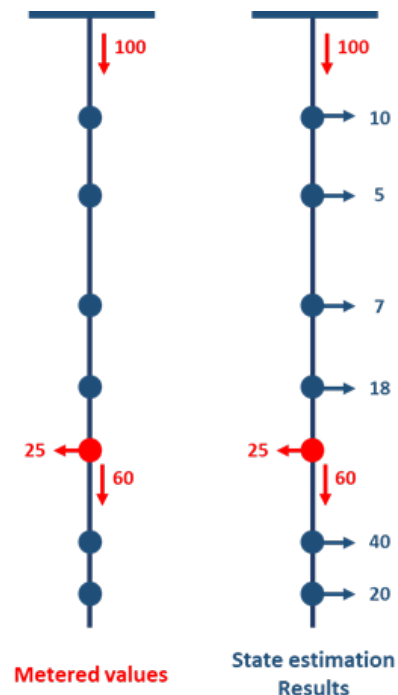


The main applications are:

#### 1.4.2.1 State Estimation (SE).

The state estimator is an integral part of the overall monitoring and control systems for transmission networks. It is mainly designed to provide a reliable estimate of the system values. The state estimators could calculate various system variables with high confidence despite the facts that their measurements may be corrupted by noise or could be missing or inaccurate.

Even though we may not be able to directly obtain the system values, they could be calculated 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.



#### 1.4.2.2 Load Flow Applications (LFA).

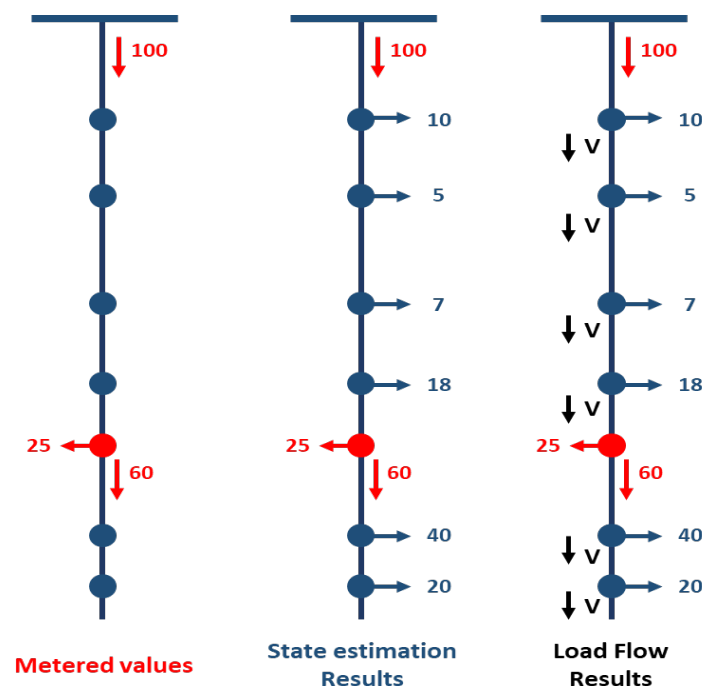
The Load Flow study is an important tool involving numerical analysis applied to a power system. The load flow study usually uses simplified notations like a single-line diagram and focuses on various forms of AC power rather than voltage and current. It analyses the power systems in normal steady-state operation. The purpose 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 available, active and reactive power flow on each branch as well as generator reactive power output could be analytically determined.



Due to the nonlinear nature of this problem, various numerical methods are employed to obtain a solution that is within acceptable tolerance limits. 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 assets.

For a better understanding of the combined use of those two applications, an example is shown in the figure below. The figure shows a scheme that represents a feeder with only the metered information and a second scheme that uses the State Estimation, which estimates the load in the transformer stations without this information. The third example shows the results obtained after running the load flow, which calculates all flows and voltages. The estimated values will probably to some extent modified by the load flow due to 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.

**Figure Error! No text of specified style in document.-3: Example of a State Estimator**



#### 1.4.2.3 Generation Control.

A generator embedded in the distribution networks normally has a power capacity that is compatible with the feeder where it is connected to. The generators embedded in the distribution networks would be significantly smaller than units connected into the transmission grid. These groups will be easy to operate and at the same time support network security, frequency and voltage maintenance. The big control panels filled with push buttons and analogic measures in the past, have now been substituted by digital systems that provide much better capabilities to operate the generator and monitor system values.

This application is normally developed by each generator suppliers for their own generators. This control application always runs on the top of a SCADA System and the generation control



is limited in most cases to the generator from the same supplier. For this reason, in some cases, we found that two SCADA systems were used to control generators from two 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 poor quality on frequency control. This methodology is used in some isolated systems.
- ✓ **Automated:** The computer controls the deviation of the frequency, generates the raise / lower signals to the generators control elements to maintain the frequency precisely to set point. Even some dispatches 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 that it allows fair interchanges.

#### 1.4.2.4 Network Connectivity Analysis (NCA)

By analysing the network information obtained through the SCADA system, NCA considers the position of all switching elements and assists the operator by illustrating the state of the distribution network, which includes the information for the radial mode, loops and parallels in the network.

#### 1.4.2.5 Switching Schedule & Safety Management.

Control engineers prepare switching schedules to isolate and disconnect a section of a network in which the work has to be done. The Distribution Management System (DMS) validates the possible working schedules based on the results of the network model. When the required section of the network has been isolated, 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.

#### 1.4.2.6 Voltage Control

Voltage could be controlled in the system, using:

- ✓ Reactive power generation or absorption in generators (VAR control)
- ✓ Tap Changers - Modifying the transformer's ratio, changing taps with temperature variations. 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.

- ✓ Autotransformers: These transformers could have a turns-ratio that is very close to 1.00, which means that the voltage variation is small and these are used only for voltage control at 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 automated, controlling the voltage in the connection point.

#### 1.4.2.7 Short Circuit Allocation.

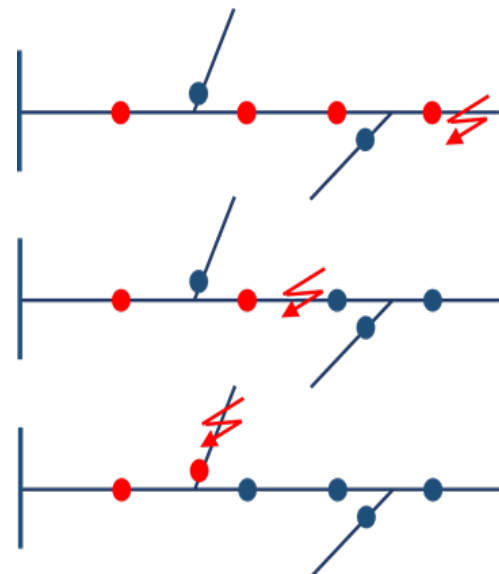
Unexpected and undesired short circuits in the network are a reality and that cannot be avoided but could be reduced with good maintenance that will improve the system reliability. The impact of a short circuit and its impact into the Quality of Service can be mitigated by detecting the portion of the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

Short circuit allocation is based on the use of short-circuit current elements in the network that simply detects and communicate the fault details 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 dots represent the locations with elements that detected the passing of the current.

For each location of the short circuit in the network (feeder), there is a different configuration of elements which detects the pass of the short-circuit current and in consequence, the short circuit location itself which will allow the operator to perform actions for restoring the system immediately.

The detectors shall be capable of communicating with the control centre (could be based on a Power-line communication (PLC) or General Packet Radio Services (GRPS) communication systems) or incorporating the signal into an RTU that collects other types of information.



#### 1.4.2.8 Load Shedding Application (LSA)

One of the key aspects of an electric system control is to maintain the equilibrium between load and generation. In order to control the generation to match the demand, operation planning could be done on a day-ahead based or real-time adjustments could be made.

But at times when the demand increases or decreases significantly or at times when key generation units' trip, the balance between supply and demand is lost. The system reacts by modifying the system frequency that must be corrected by 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 and this is known as load shedding.

This reduction or Load Shedding could be done manually or could be automated using a Load Shedding Application (LSA). This is the most common method is to reject some load from the system when the frequency reaches unacceptable levels. The load shedding with the double

objective to protect the generators and to stabilize the network, which makes the restoration easy and faster.

The load shedding is normally “triggered” by a protection system that scans the frequency or the frequency variations. Once the frequency is recorded lower than acceptable values, the protection system trips some feeders to reduce the load reduction. In a system normally there are a few frequency levels defined to reduce the load (between 3 and 5) and at each frequency level, a certain amount of load is rejected (from 15% to 25%).

#### 1.4.2.9 Fault Management & System Restoration (FMSR).

Some incidents in the network are, because of the way they are caused, impossible to avoid or reduce. For example, it is difficult to avoid the damage that could be caused by storms or other weather conditions but the quality of service could be improved by ensuring faster restorations.

Fault Management & System Restoration (FMSR) applications tend to reduce the restoration time by automating a 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). Once the allowed time has elapsed, in order to test a cable, the operators have to be physically present at the fault location, to verify there is no danger to the public during the test.

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

#### 1.4.2.10 Distribution Load Forecasting (DLF)

As mentioned in the previous section, one of the main aspects is to ensure the balance between generation and load. The system load includes the client's consumption and the system's technical and nontechnical losses.

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

The traditional energy balance equation is:

$$DG + RE + IB = LO + SL$$

Where: DG 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:

$$DG = (LO + SL) - RE$$

Estimated together
Estimated Individually

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

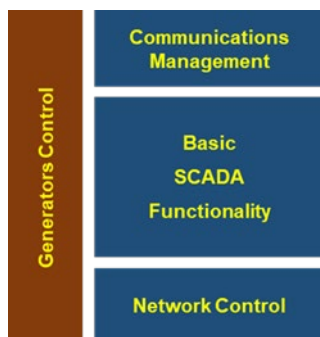
- ✓ Load + Losses forecast, this will require a cleaned historic load data base.
- ✓ Renewable or non-dispatchable generation, which could be estimated globally on the island or independently for solar or wind parks.

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.

#### 1.4.2.11 Load Balancing via Feeder Reconfiguration (LBFR)

The Load Balancing via Feeder Reconfiguration involves automating 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 develop an optimal solution to manage the network.



#### 1.4.3 Requirements of the Distributions Systems

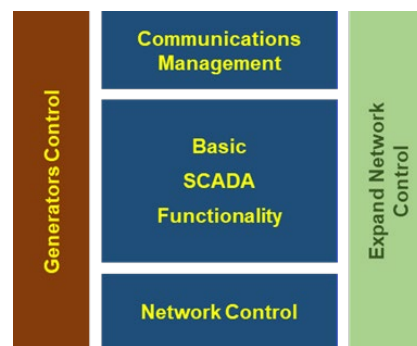
For the Distribution Systems such as the one in Chuuk or as seen in the other islands, the following three requirements have been identified:

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

#### 1.4.3.1 Network Control and Monitoring

For network control and monitoring:

- SCADA systems normally provides enough information for system monitoring and control
- The user interface should be simple and capable to show the network at different levels depending on the real-time requirements
- The options for zoom, panning and clustering should be available in the system.
- The capacity for supervisory control shall be protected in a two steps operation (i.e. selection and execution)



#### 1.4.3.2 Quality Assurance

Maintaining a good quality of service is essential for any distribution system. This could be considered under two aspects:

1. **Service Continuity:** The first challenge is to maintain the service under different situations and circumstances.

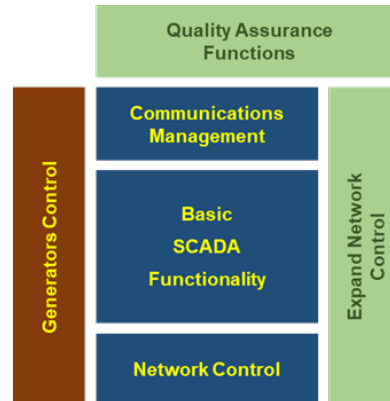
The continuity of services could be affected by external incidents into the network, such as; lightning, storms, high-speed winds, car accidents and vegetation. There are only limited ways to avoid the existence of those incidents, but they can be mitigated using more secure network elements.

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:** The quality of supply is maintained by managing the main parameters such as the frequency, voltage and harmonics.

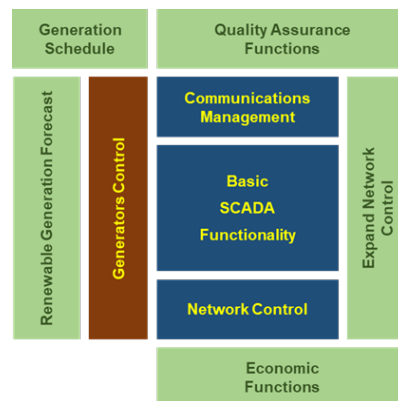
Normally external factors do not affect the quality aspects. Operation planning process, which is normally done for a day in advance, considers the resources existing or made available for

operation. Some applications are available to control those aspects, together with the reserves capacity and allocation, which does not directly impact the quality, but in case of other incidents, such capacity will help to limit the extent and magnitude of the incident and eventually reduce the restoration time.

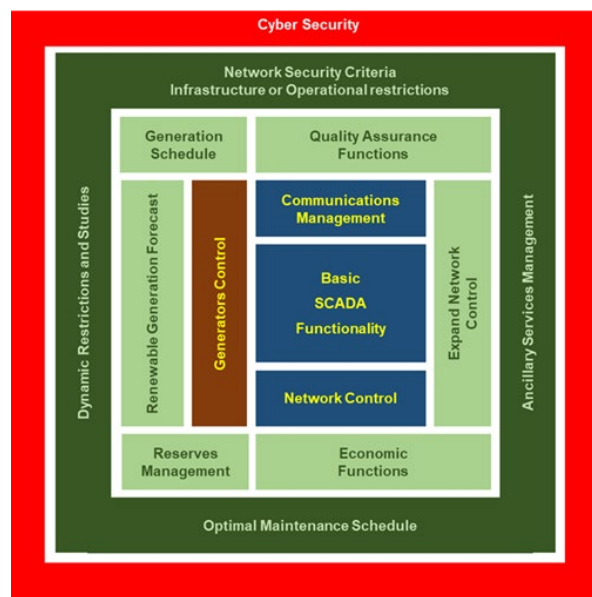


#### 1.4.3.3 System Economic Optimization

Apart from ensuring continuity of supply and quality of power, it is important that the network is managed in the most economical way. Firstly, to run the power system in the most economical way, the generation schedule should be optimised. Once the generation is optimised, the network operator's main aspect is to reduce system losses. The SCADA application provides tools to control network losses and ensures optimal switching in the network to reduce feeder losses.



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



#### 1.4.4 Recommendation between EMS and DMS

Both are systems have 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 for Chuuk is to implement a tailored Distribution Management System (DMS) instead of adapting an EMS for the Island.

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.

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