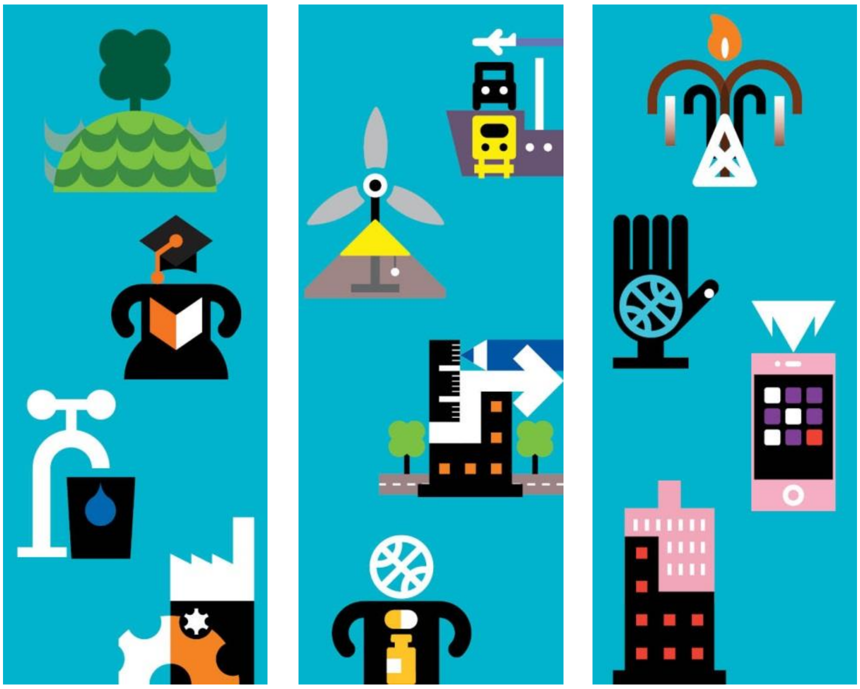

Malawi Grid Capacity Study

Final Report

June 2016

Management and Engineering Technologies International (METI)

Mott MacDonald

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Issue and revision record

Revision	Date	Originator	Checker	Approver	Description
3	30/06/2016	J de la Bat	D Leeburn	P Tuson	Final Report

Contents

Executive Summary

Malawi is short of generation capacity and is actively looking for ways to increase public and private generation. There are varying opinions on the integration capacity of additional generation onto the existing ESCOM Malawi 132kV, 66 and 33kV transmission grid.

The Client is looking to gain a good understanding of how many additional Megawatts (MWs) Malawi's grid can absorb on the current system, to guide and facilitate Power Purchase Agreement (PPA) development with Independent Power Producers (IPPs).

As some of these IPPs are proposing Photovoltaic (PV) solar power solutions, the Client is also looking to get a sense of how much variable or intermittent power Malawi's grid can handle today and over the next 12-24 months, until MCC and the World Bank's Transmission and Distribution (T&D) improvements come on line. There is a belief in Malawi that the electricity network can only handle up to 5% of installed capacity in new variable Renewable Energy (RE) sources, limiting the size of any solar IPP to 17.5 MW. The Client requires this assumption to be explored, tested and confirmed or disproved.

Two study years are considered in this study as follows:

1. The "as-is" 2016 system
2. The 2018 system – certain transmission upgrades and additional diesel generation are planned to be commissioned by 2018

In each year of study the maximum export capacity at individual transmission busbars was determined. The export capacity was determined by the thermal limits, voltage limits and fault levels after the integration of new generation.

Thereafter, a study was carried out to determine the maximum individual renewable plant size through observing the frequency stability of the power system following a loss-of-plant contingency. The frequency stability study was carried out for 2016 and 2018. Simulation results were compared with measurements taken doing a controlled generator unit trip at Nkula A Power Station. Measured response and simulated response showed excellent correlation which provides confidence in the results of the study.

The conclusions are presented below.

1. Steady-State Analysis:
    - The load flow studies indicate that connections of 4MW to 300MW are possible from a steady state point of view at various busbars in the network.
    - System losses decrease by up to 20% after integration at some areas of the network. However, if the distributed generation exceeds local load, losses start to increase and even exceed previous levels in some cases.
2. Frequency Response Studies
    - Modified governor settings were found to provide good correlation with an actual Nkula A generator tip.
    - The limiting scenario for a PV connection in the meshed network is 17MW.
    - The limiting scenario for a PV connection in the radial northern network is 15MW.
3. PV integration Analysis

- Although the northern system is suitable for PV connections from a system losses, geographical and network diversity point of view, it is limited in the amount of generation it can transfer due its radial nature especially for 2016 (a trip of the radial line disconnects northern PV plants from the bulk network).
- Due to the meshed nature of the Southern and Central parts of the transmission system, larger increments of power can be connected on these networks.
- With the assumed reserve margin, multiple uncorrelated (at least 20km apart) PV units can theoretically be connected across the system however it is recommended that this is initially limited to 70MW for system inertia and governing response reasons.
- It should be noted that if PV is to be integrated, an operational project-specific study will need to be undertaken in order to determine the required amount of online units (for both inertial and governing purposes) under all possible conditions.
- PV plants take up approximately 2 hectares per MW of land and this needs to be considered when positioning plants.
- The overall study undertaken indicates that for all normal operating conditions up to 2018, a loss of a 17MW PV plant in the meshed system will not induce UFLS if only one (1) unit of Nkula A is offline. The same is true of 15MW in the radial northern system.
- No additional load should be connected after the integration of PV plants. This is due to the fact that PV has a narrow mid-day generation band where maximum power is achievable and even then it is not guaranteed. Adding extra load will in fact decrease the existing small reserve margins (Appendix G), increasing the chance of invoking UFLS and decreasing system reliability.

4. Peaking Plant Analysis
   - Peaking plants should initially be limited to around 17MW in size
   - The plants should be integrated in a meshed area of the grid to increase the availability of the peaking plant and overall system security
   - The peaking plant was found to improve the system frequency response (increased inertia and governing capability)
   - The peaking plants will be transiently stable if integrated within the meshed system
   - Peaking plants should only be run at system peak and not at any other time (for economic reasons)
5. Thermal Base Load Analysis
   - Base load plants need to provide some spinning reserve in order to allow larger units to be connected to the system (equipment prices, unit efficiency and economies of scale). An example is 4x30MW units all operating at 26MW.
   - As with the diesel peaking plants, the thermal plants should be integrated in a meshed area of the grid to increase system security
   - Thermal plants improve the system frequency response (inertial response and governing capability)
   - The plants will be transiently stable if integrated within the meshed system
   - Once an international interconnector is built, larger thermal units may be connected to the power system. This is because the SAPP system can then provide additional inertial response and governing capability

The following are recommendations based on findings and conclusions of this study:

1. Multiple 17MW PV power plants can be connected to the meshed network at system substations which meet the MEC requirements.
2. Multiple 15MW PV power plants can be connected to the radial northern network at system substations which meet the MEC requirements.
3. PV plants larger than 17MW can be installed if they are built and connected in such a way that a single contingency only removes 17/15MW from the system at a time. This can be achieved through multiple transmission lines and or transformers etc.
4. The total of installed PV should initially be limited to 70MW.
5. The UFLS relays should be reconfigured to operate instantaneously to improve system frequency recovery.
6. Operational studies should be carried out for each PV plant to be connected to ensure that there will always be enough system inertia and governing reserve to ride through a plant trip under all operational conditions.
7. PV power plants should be dispersed in the following manner:
   - Connected to different backbone transmission systems (e.g. northern system, Lilongwe system, Golomoti system, Salima system, various Blantyre systems) which creates electrical connection diversity
   - Connected in a geographically dispersed manner with electrical and weather diversity benefits
8. No Additional load should be connected to the ESCOM power system
9. If more load is to be serviced on the ESCOM power system, the following infrastructure should be prioritized:
   - <u>SAPP Interconnector</u> (emergency reserve, regulatory reserve, system inertia from the SAPP system, energy (kWh) when available from SAPP countries, diversity from hydro, export of Malawi PV kWh when available)
   - <u>Peaking HFO or Diesel plant</u> (already in the mini-IRP and makes sense for system peak). HFO has cheaper USc/kWh, fast frequency response but likely to be too expensive as spinning reserve for non-dispatchable PV during the day
   - <u>Baseload coal</u> (emergency reserve, regulatory reserve, kWh, diversity from hydro, fast frequency response) Probably 2 x 100MW units due to the size of the Malawi system versus cost savings in terms of unit size (economies of scale)
   - <u>Baseload gas</u> (emergency reserve, regulatory reserve, kWh, diversity from hydro, fast frequency response). If gas can be obtained at ~$5/GJ to $7/GJ, gas will likely be comparable to coal but a gas source needs to be found
   - <u>Solar PV</u> (kWh, non-dispatchable, can help with frequency response if output constrained, does not increase/improve system inertia). PV can decrease coal or gas input costs when sun shining (kWhs) but cannot be relied upon for capacity
   - <u>Hydro</u> (hydro is weather dependent and if poor rainfall all hydro generators equally affected). Malawi needs to diversify away from hydro until other baseload, interconnector or peak generation sources are in place
10. Although a Mini-IRP document has been developed by MERA in Malawi, a further refinement to this IRP should be considered taking into account demand forecasts, forecasted Load Duration Curves (LDCs), Shire River hydrology, competing generation capital and variable costs and planned imported/exported generation.

1 Introduction

1.1 Background

Malawi is short of generation capacity and is actively looking for ways to increase public and private generation. There are varying opinions on the integration capacity of additional generation onto the existing ESCOM Malawi 132kV, 66 and 33kV transmission grid.

The Client is looking to get a solid understanding of how many additional Megawatts (MWs) Malawi’s grid can absorb on the current system, to guide and facilitate PPA development with IPPs.

As some of these IPPs are proposing Photovoltaic (PV) solar power solutions, the Client also needs to get a sense of how much variable or intermittent power Malawi’s grid can handle today and over the next 12-24 months, until MCC and the World Bank’s Transmission and Distribution (T&D) improvements come on line. There is a belief in Malawi that the electricity network can only handle up to 5% of installed capacity in new variable renewable energy sources, limiting the size of any solar IPP to 17.5 MW. The Client requires this assumption to be explored, tested and confirmed or disproved.

1.2 Report Structure

The structure of this report is as follows:

- Section 2 presents the study assumptions and general methodology for the study
- Sections 3-8 present the technical analysis from the study
- Section 8 presents the conclusions of the study
- Section 9 presents the recommendations of the study

2 Study Assumptions and Methodology

This section outlines the assumptions and methodology by which the study was carried out.

2.1 Steady-State Studies and Assumptions

- The Maximum Export Capacity (MEC) will be determined at all 66kV and 132kV busbars in the existing and future transmission networks. Existing generation busbars are excluded as diversification of generation both technologically and geographically is required in Malawi in order to increase reliability.
- Studies will be undertaken to comply with the Malawi Grid Code Final 2015.
- MEC values will be undertaken assuming no installation of additional reactive devices e.g. shunt capacitor banks or shunt reactors.
- Studies will be undertaken taking into account normal operating conditions (N-0) only. It is the Consultant's experience that IPP developers are only interested in system healthy conditions as the chance of equipment failure in the transmission system is low. The consequence of failure rates above standard levels is normally dealt with in the Power Purchase Agreement (PPA).
- Grid code limits will be applied as follows:

Table 2.1: Voltage Limits

System Condition	Minimum Voltage (p.u.)	Maximum Voltage (p.u.)
Healthy (N-0)	0.95	1.05
Emergency (N-1)	0.90	1.10

Table 2.2: Thermal Limits

Equipment	Normal Loading (%)	Emergency Loading (%)
Transmission Line	100	120
Cable	100	100
Transformer	100	100

- All generation units are available for operation
- Studies will be undertaken for two load and generation scenarios as follows:
  - Maximum noon load (maximum solar PV output)
  - Minimum noon load (maximum solar PV output)
- Studies will be undertaken assuming IPP generator operating modes as follows:
  - Constant power factor studies (generation is not permitted to contribute to localised voltage control)
  - Constant voltage studies (generation may contribute to localised voltage control by varying the reactive power output between 0.95 leading and lagging power factors)

It should be noted that constant voltage studies will only be carried out for instances where the limiting factor is the voltage itself.

2.2 Stability studies and Assumptions

Frequency stability studies include the following:

- Detailed generator and governor modelling
- System response to loss of large increments of generation
- Under frequency load shedding (UFLS) modelling

Transient stability studies are not required for the following reasons:

- PV power plants are asynchronously connected to the grid via inverters so no pole slipping (as with synchronous power plants) can take place
- Most of the existing hydro generation power plants are in close proximity to each other (Kapichira, Tedzani and Nkula) and are connected via a meshed transmission system

The stability studies will assume that no additional load is added as intermittent generation technologies cannot be considered as base load generation. Further discussions on the addition of load are presented in Appendix G.

Another study goal is that the addition of any new generation should not increase the chance of invoking Under Frequency Load Shedding (UFLS).

2.3 Exclusions

The following tasks are not included in this study:

- Harmonic and flicker studies
- Grid Code Compliance studies including:
  - High voltage ride-through (HVRT) and Low voltage ride-through (LVRT) analysis using Original Equipment Manufacturer (OEM) Wind Turbine (WT) model or standard model
  - Dynamic reactive power analysis using OEM Wind Turbine (WT) model or standard model
  - Review of frequency response
- Environmental studies
- Designs and drawings
- Techno-financial and options studies

2.4 General Methodology

Two study years will be considered as follows:

3. The as-is 2016 system
4. The 2018 system – certain transmission upgrades and additional diesel generation is planned to be commissioned by 2018

Appendix A includes a list of planned Transmission lines for Malawi. Appendix F includes a list of planned thermal generation projects for Malawi.

In each year of study the maximum export capacity at individual transmission busbars will be determined. The export capacity will be determined by the thermal limits, voltage limits and fault levels after the integration of new generation.

Thereafter, a study will be carried out to determine the maximum individual plant size through observing the frequency stability of the power system following a loss-of-plant contingency. The frequency stability study will be carried out for 2016 and 2018.

2.5 Data Collection

Data was collected through email correspondence between the Consultant and the relevant ESCOM personnel as well as a brief site visit from the 26th-29th January 2016. The details of the data collection phase are presented in Table 2.3 below.

Table 2.3: Data Received

Item	Description	Source
1	2015 and 2020 Digsilent simulation files	ESCOM
2	List of expected commissioning dates for future transmission and generation projects (Appendix A)	ESCOM
3	Under Frequency Load Shedding (UFLS) Relays and Loads (Appendix B)	ESCOM
5	NCC SCADA snapshots (Appendix C)	ESCOM
3	2014 Generation Log Sheets (Appendix D)	ESCOM
4	Malawi IRP 2010	ESCOM
6	Power Trading Report	ESCOM
8	Transmission line and transformer parameters	ESCOM
9	Draft Governor Modelling Report	ESCOM

The site visits that were carried out included meetings with the ESCOM Planning Department, NCC and GCC as well as briefly visiting the Nkula and Tedzani power stations.

A second round of data collection was carried out to determine the accuracy of the dynamic model developed. This was carried out between the 30th May and 3rd June. A planned trip of a single unit at Nkula A was carried out and the frequency response was recorded. Mott MacDonald worked closely with ESCOM generation, planning and national control in order to obtain results.

3 Base Case System Modelling

The following sections describe how the base case models for 2016 and 2018 were developed using the data received from ESCOM.

3.1 System Generation Curve

The monthly average of daily generation profiles for 2014 are presented in Figure 3.1 below. The generation profiles give an indication of the ESCOM load profiles which have a fairly distinctive shape. The minimum system load occurs during the early hours of the morning and increased system loading occurs between 6-8pm as expected. The working day profile is interesting as it plateaus from 6-12am then drops off at 12 noon until system peak between 6pm and 9pm.

The unusual drop off in the afternoon load is a natural occurrence and not due to load shedding.

This working day profile (between dawn and dusk in the profile below) is of particular interest to this study as it coincides with typical hours of solar PV production (daily solar irradiation).

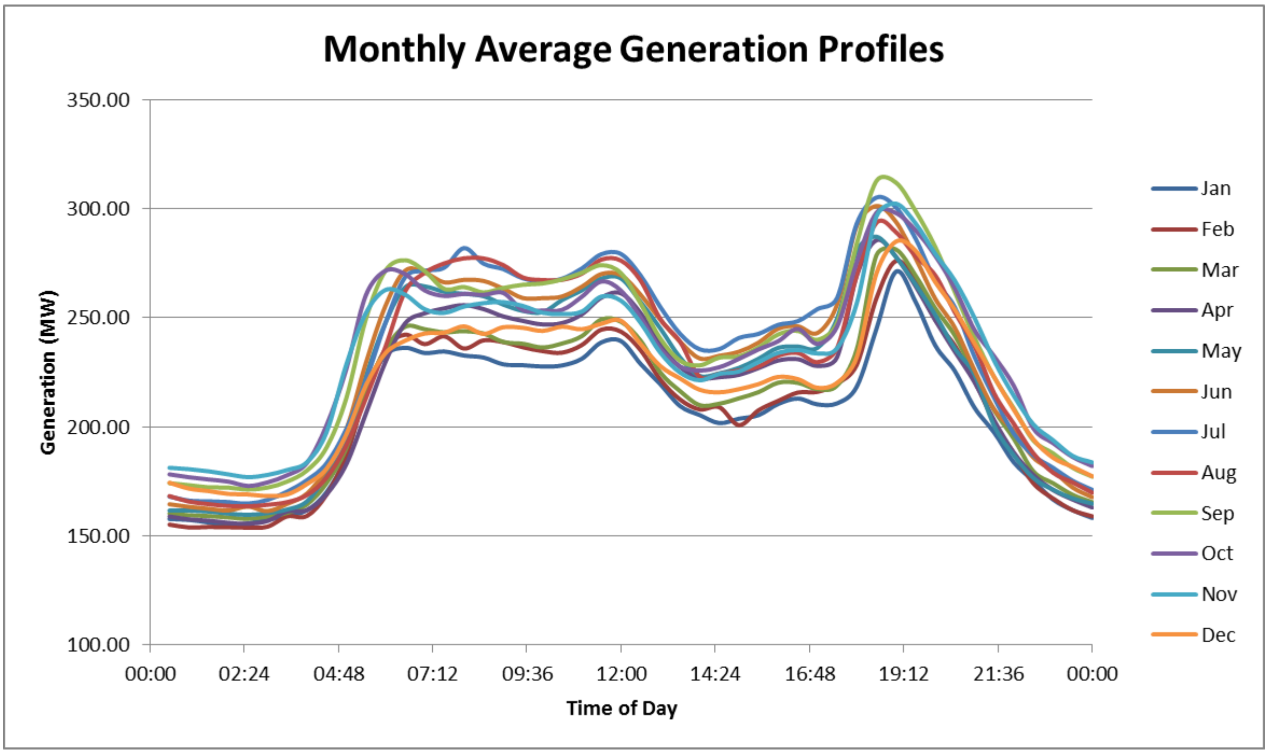


Figure 3.1: Monthly average generation profiles

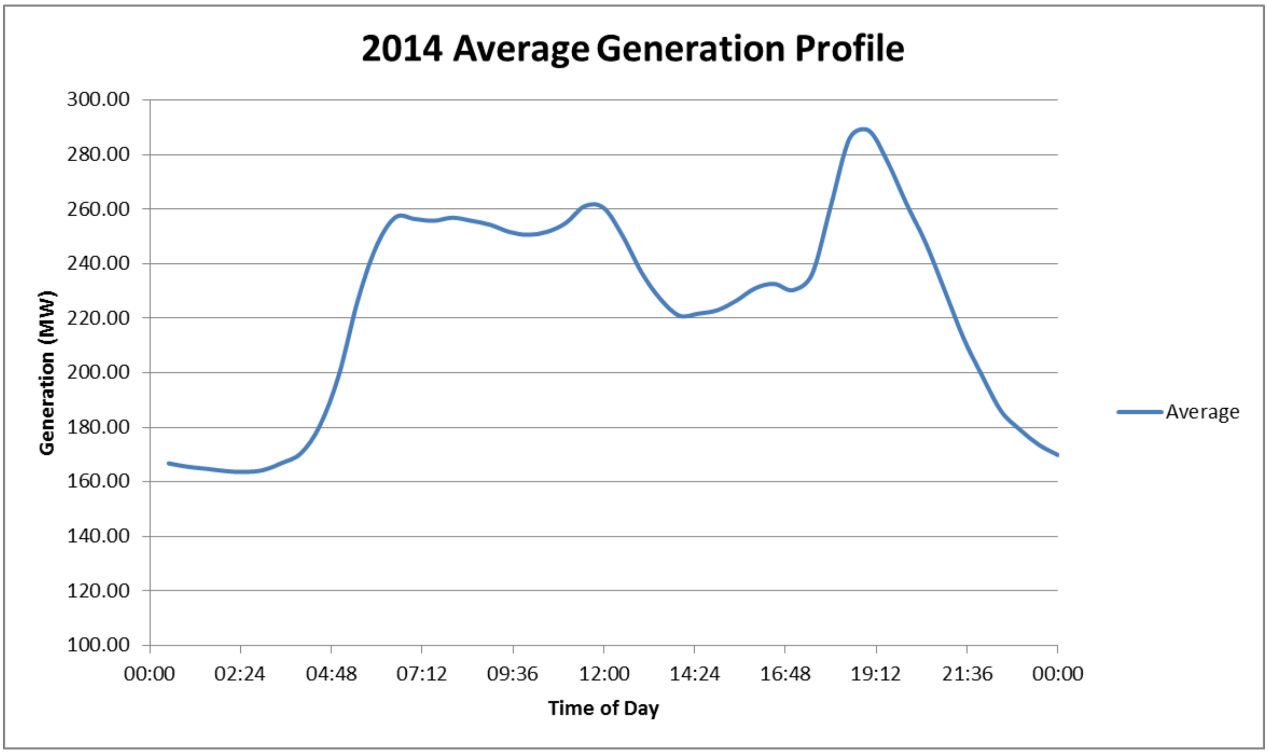


Figure 3.2: 2014 average generation profile

3.2 Additional infrastructure for 2018

A number of projects are due to be completed by 2018. These include some additional generation as well as major changes to the transmission system topology. A list of these projects is provided below.

Table 3.1: Projects to be completed by 2018

Type	Description
Generation	Kanengo 10MW Diesel
Generation	Mzuzu 6MW Diesel
400kV Line	Phombeya – Nkhoma
132kV Line	Chinteche – Luwinga – Bwengu
132kV Line	Nkhoma – Bundu
66kV Line	Lilongwe Ring
Substation	Associated substations for the above projects

The line parameters for the additional lines as well as the transformers parameters for the new substations were obtained from the 2020 simulation file received from ESCOM.

3.3 Loading conditions for 2016 and 2018

The load of the 2015 base case model received from ESCOM was adapted to represent the generation loading observed in the 2014 curves above. The maximum and minimum load values between 12am-2pm are used for the study as it represents the time at which the solar PV plant is likely to generate at its capacity. The resultant load was adjusted by 6% per year to reach the base case values presented below:

Table 3.2: Base Case System Load

Year	Midday Maximum	Absolute Maximum	Absolute Minimum
2016	270MW	303MW	150MW
2018	303MW	327MW	170MW

3.4 Generation Dispatch

The base assumption used for the study is that all generation units are available for operation. The generation is dispatched so that there is enough reserve for the largest single unit on the system (i.e. 1 unit at Kapichira). This is a reasonable assumption based on the information gathered during the site visits. The dispatch of the installed generators is provided in Appendix I.

3.5 Generator Governor and Exciter Models

The generator governors were modelled using information from the Draft Governor Modelling Report received during data collection. The models were replicated and tuned in order to obtain a satisfactory response. The Consultant in conjunction with ESCOM carried out confirmatory site frequency response tests in order to determine the validity of the models that were used. The generator exciters were modelled using standard models and values. Both the governor and exciter models can be found in Appendix D and E.

Figure 3.3 below compares the measured frequency response with the simulated response whilst Table 3.3 provides a comparison of the unit dispatch before the trip event. The dispatch values are similar and the main differences are due to Nkula B G6 having problems with its bearings preventing it from operating normally resulting in Tedzani I and II needing to operate at full power.

Nkula A G2 (dispatched at 8MW) was tripped and the frequency response recorded. The correlation between the simulated and measured responses is very good, especially at the frequency nadir. The frequency nadir will be used in the analysis to determine the maximum unit size of new plants and it is therefore important to have confidence in the simulated accuracy.

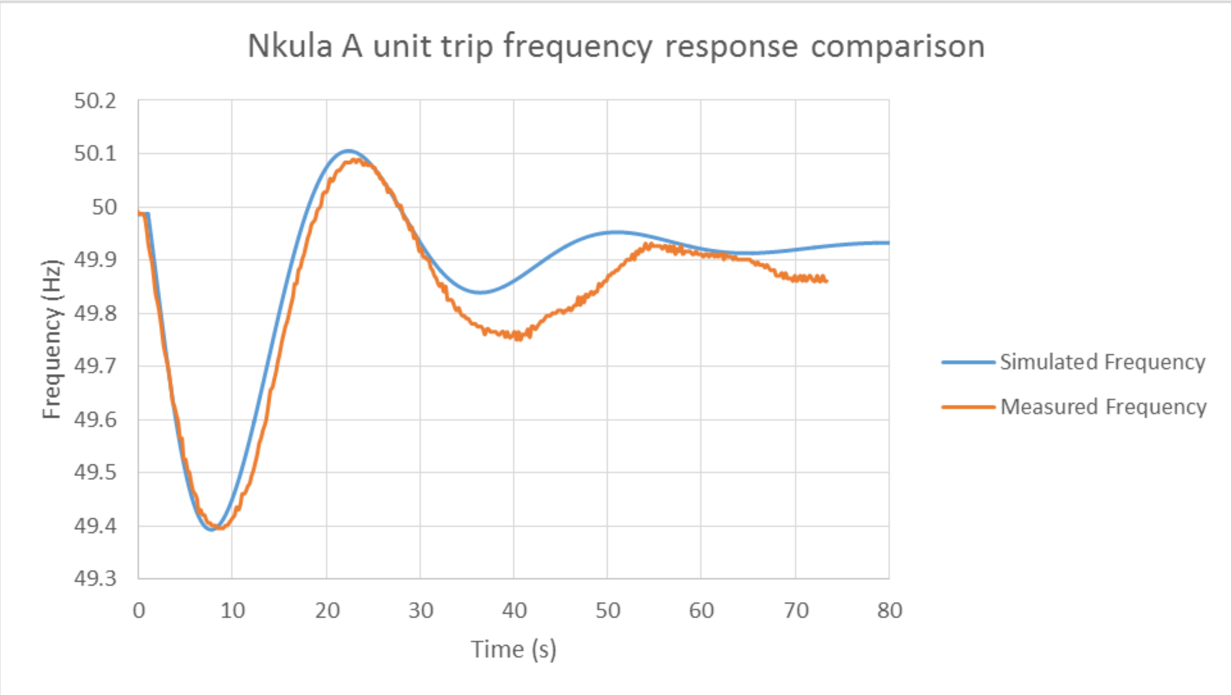


Figure 3.3: Measured vs Simulated Frequency Response

Table 3.3: Unit Dispatch Comparison

Generator	Approximate Dispatch	Simulated Dispatch
Nkula A G1	7.3	6.9
Nkula A G2	8	8
Nkula A G3	7.3	6.9
Nkula B G4	16	14.7
Nkula B G5	15	14.7
Nkula B G6	7.5	14.7
Nkula B G7	15	14.7
Nkula B G8	16	14.7
Tedzani I G1	10	10
Tedzani I G2	10	10
Tedzani II G3	10	10
Tedzani II G4	10	10
Tedzani III G5	-	-
Tedzani III G6	26	22.5
Kapichira I G1	19.6	22.5
Kapichira I G2	21.6	22.5
Kapichira II G3	24.2	22.5
Kapichira II G4	24.9	22.5
Wovwe Lumped	Unknown	4.3

4 PV Maximum Export Capacity Studies

4.1 Load Flow Studies

Load flow studies have been carried out for both scenarios (2016 and 2018) and indicate that sites can accommodate between 4-300MW depending on the site and system condition.

The tables below are an extract of the results under peak mid-day loading for the Northern part of the 66kV Transmission system. The full set of results for the entire system can be found in Appendix H. Table 4.1 shows the MEC for 2016 under unity power factor (UPF) control and the association loss reduction and limiting factor.

When the limiting factor is a busbar voltage, a further load flow was undertaken using voltage control (VC) which typically increases the MEC. When operating in VC, the power factor is limited to 0.95 leading or lagging. The results show that for all busbars south of and including T/Hill, up to 21MW can be exported under UPF control and 55MW can be exported under VC. All busbars North of T/Hill can only export 4.3MW due to the 33kV bottleneck from T/Hill to Bwengu.

With the introduction of new transmission line infrastructure in 2018, the MEC increases due to improved voltages and additional local load in service. These results are given in Table 4.2. A negative loss reduction indicates an increase in system losses after integrating the new generation.

Table 4.1: 2016 Peak mid-day load Northern 66kV results

Busbar	Voltage	Unity Power Factor MEC (MW)	Loss Reduction (MW)	Limit	Voltage Control MEC (MW)	Loss Reduction (MW)
Bwengu	66kV	4.3	1.88	Thermal	-	-
Chikangawa	66kV	21	4.02	Voltage	45	-1.86
Chintheche	66kV	21	4.74	Voltage	55	1.53
Karonga	66kV	4.3	1.80	Thermal	-	-
Livingstonia	66kV	4.3	1.79	Thermal	-	-
T/Hill	66kV	17	4.48	Voltage	55	-5.96
Uliwa	66kV	4.3	1.76	Thermal	-	-

Table 4.2: 2018 Peak mid-day load Northern 66kV results

Busbar	Voltage	Unity Power Factor MEC (MW)	Loss Reduction (MW)	Limit	Voltage Control MEC (MW)	Loss Reduction (MW)
Bwengu	66kV	20	2.11	Voltage	50	-1.43
Chikangawa	66kV	21	1.69	Voltage	45	-4.87
Chintheche	66kV	20	2.34	Voltage	45	-0.29
Karonga	66kV	12	0.43	Voltage	25	-3.75
Livingstonia	66kV	20	0.79	Voltage	40	-4.94
T/Hill	66kV	30	1.54	Voltage	35	-0.78
Uliwa	66kV	10	0.60	Voltage	35	-4.78

It should be noted that the steady state results mentioned above are not a true reflection of the potential export capacity of IPPs as the frequency response of the ESCOM system needs to be considered.

Figure 4.1 below shows the 2016 base case load flow for the Northern Transmission system. The Chintheche 132kV busbar has a low voltage as recorded during data collection and the step-down transformers are able to control the 66kV network voltages to within grid code limits. At mid-day peak, the load north of and including Chintheche approaches 20MW.

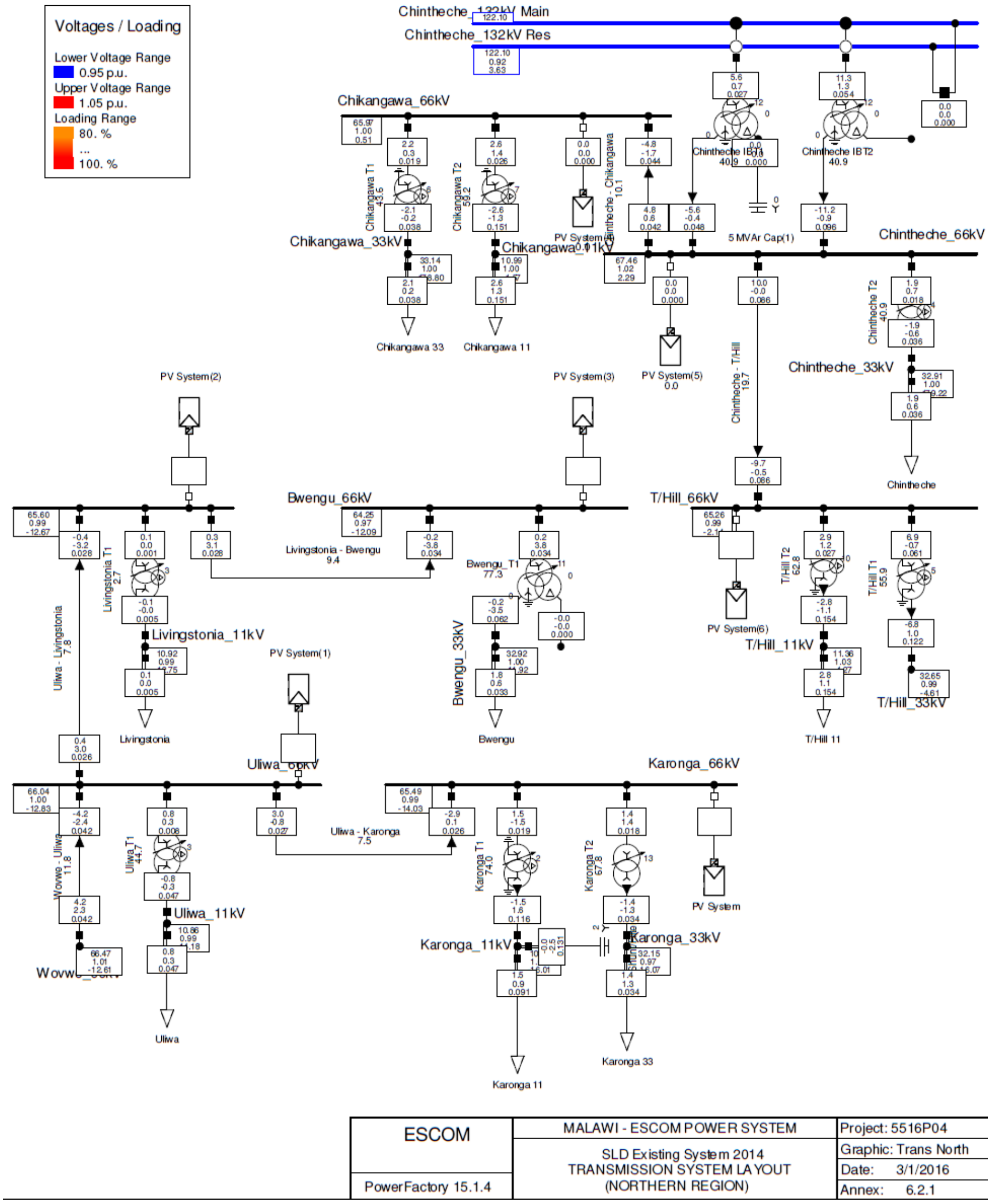


Figure 4.1: 2016 Base Case Northern Transmission System

Figure 4.2 below shows the 2016 base case load flow for the Northern Transmission system after the integration of a PV plant operating in UPF control at Karonga. It is clear that the limiting factor is the Bwengu 66/33kV transformer thermal limit once the PV plant output reaches 4.3MW. An improvement in busbar voltage at the point of integration is also observed.

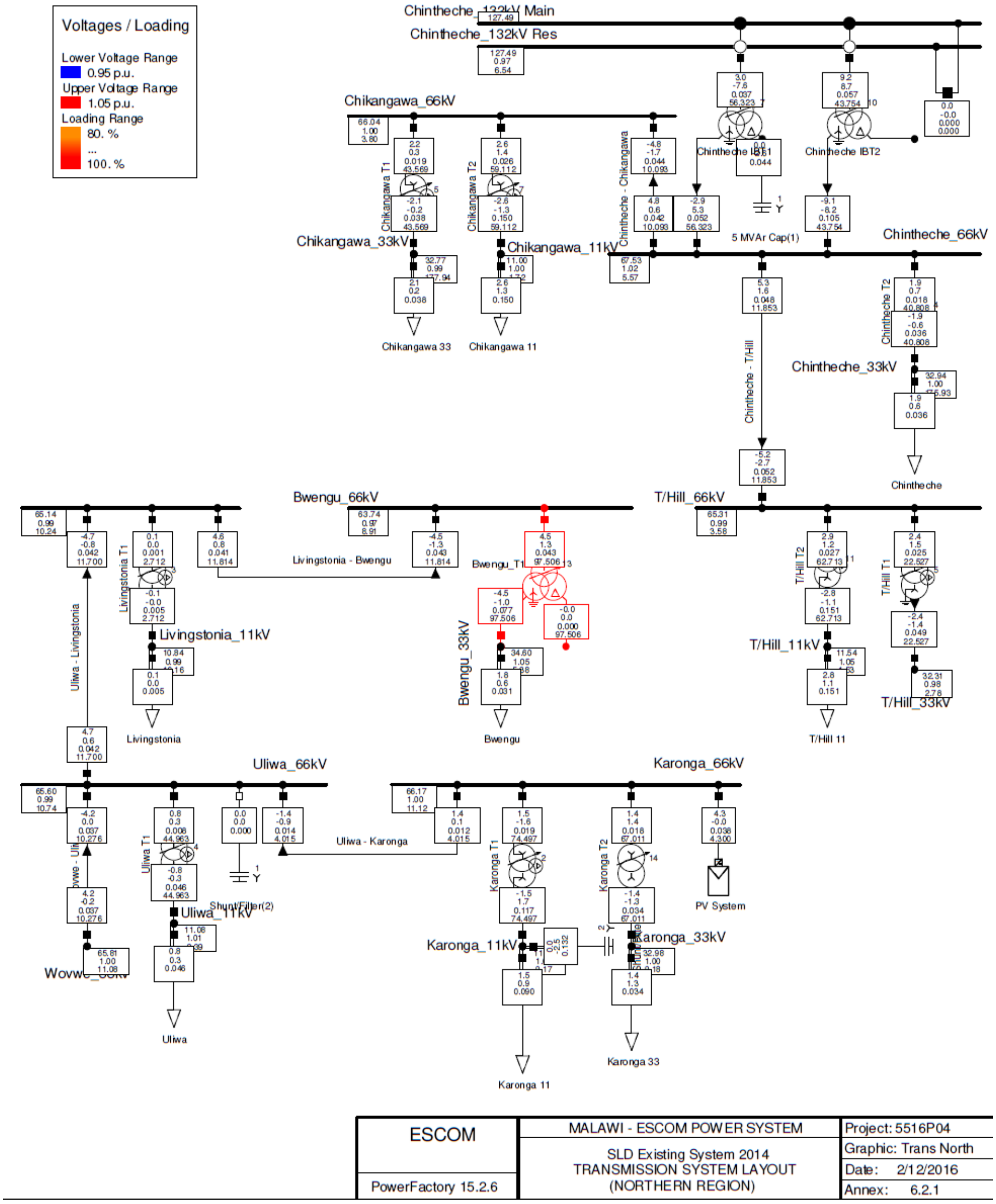


Figure 4.2: 2016 Northern Transmission System with PV at Karonga 66kV

Figure 4.3 below shows the 2018 base case load flow for the Northern Transmission system. The Chintheche 132kV busbar voltage adheres to the grid code due to the addition of 400kV and 132 kV lines in the transmission system. The 132kV line from Chintheche to New Bwengu increases the MEC of busbars north of Bwengu.

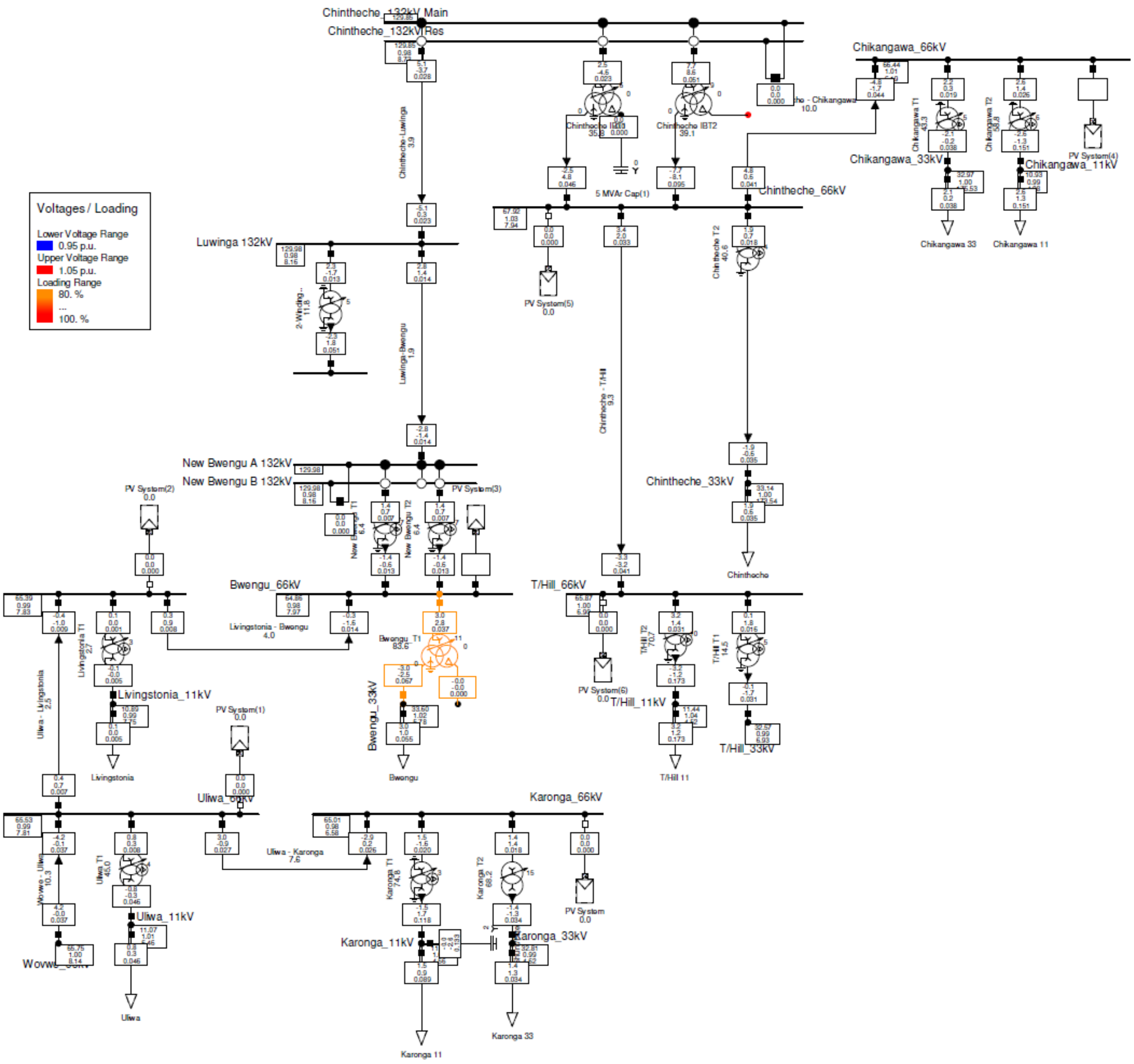


Figure 4.3: 2018 Base Case Northern Transmission System

Figure 4.4 below shows the 2018 base case load flow for the Northern Transmission system after the integration of a PV plant operating in UPF control at Chikangawa. It is clear that the limiting factor is the voltage at Chikangawa 66kV which reaches 1.05 pu. Figure 4.5 shows the effect of operating the plant in VC, increasing the output of the plant from 21MW to 45MW. The limiting factor in this case is the thermal capacity of the Chintheche 132/66/11kV transformer which reaches 99.7%.

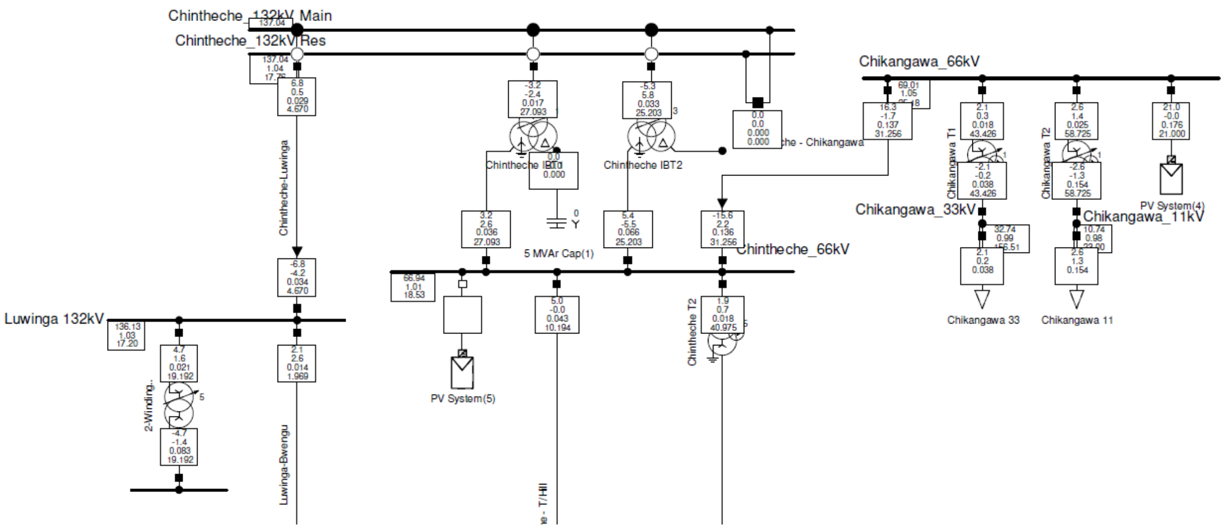


Figure 4.4: 2016 Northern Transmission System with PV at Chikangawa 66kV (UPF)

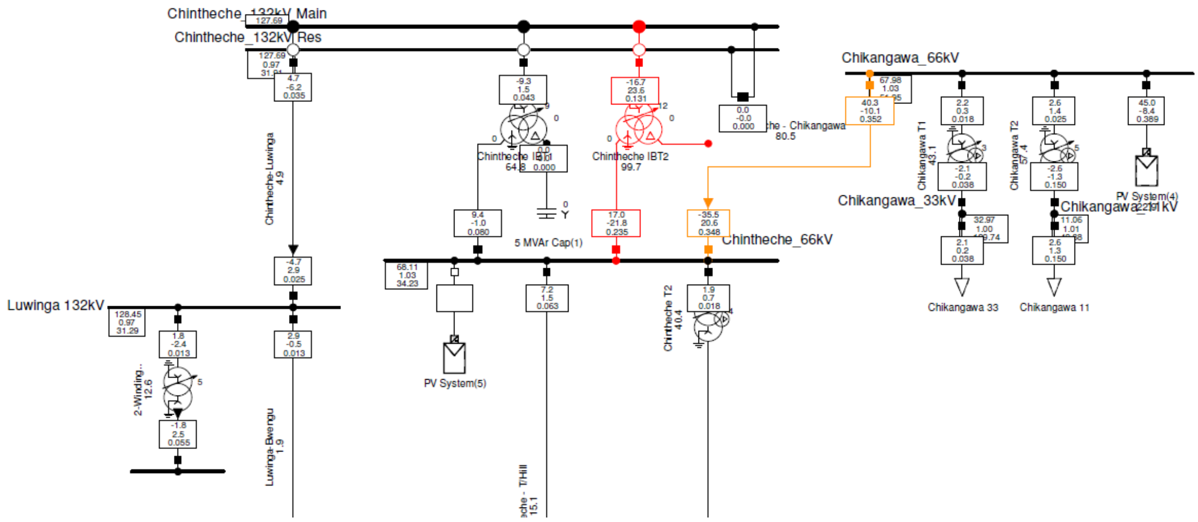


Figure 4.5: 2016 Northern Transmission System with PV at Chikangawa 66kV (VC)

4.2 System Loss Analysis

The loss analysis has revealed that generation near the load centre of Lilongwe as well as the northern part of the transmission system not only improves voltages but also results in loss reduction by up to 20% in certain cases. The system losses in the ESCOM system are mainly due to having a centralised generation area (surrounding Blantyre) and having to transport large amounts of power to the load centre of Lilongwe, as well as the northern transmission system.

The actual load of the northern transmission system is small but power is transported over vast distances at relatively low voltages. Table 4.3 below shows the total base case system losses for the two years of study.

Table 4.3: ESCOM base case system loss summary

Year of study	Max load losses (MW)	Min load losses (MW)
2016	26.25	-
2018	24	-

A decrease in system losses is observed in 2018 even though the system is more heavily loaded. This is due to the addition of 400kV and 132kV lines installed on the transmission system, increasing transmission voltages, thereby reducing the losses.

From the results presented in Appendix H It is observed that installing generation at busbars in general decrease system losses, however if the MEC is large, system losses may increase. This phenomenon can be explained as follows. The initial decrease in system losses is due to local load being serviced, thereby reducing the amount of power that is transported over large distances. If the MEC becomes larger than the serviceable local load, the losses will start to increase again as the power is transported to other parts of the transmission system.

The reduction of system losses will play a major part in the placement of any new generation onto the system which is discussed in Chapter 6.

5 PV Frequency Stability Studies

The results of the frequency stability studies are presented in this chapter. It should be noted that the reserve margin for the 2016 simulation was 34MW and the reserve margin for the 2018 simulation was decreased to 20MW due to the increasing yearly load and lack of sufficient additional base load generation. The PV plant was placed in the meshed part of the ESCOM grid. Additionally, no extra load was added after the integration of the PV plants.

5.1 Scenario Comparison

Four scenarios were considered in order to determine the worst case frequency response:

- 2016 Midday Maximum
- 2016 Midday Minimum
- 2018 Midday Maximum
- 2018 Midday Minimum

The simulation was carried out with all generators in service. A 17MW PV plant was tripped and the results represented in Figure 5.1 indicate that the worst case is 2018 midday maximum loading. This is due to the limited available reserve generation and shows that PV plants should be limited to 17MW. The remaining three scenarios have similar responses with the 2016 midday minimum representing the worst of the three. This scenario will be investigated further as it represents the current system response.

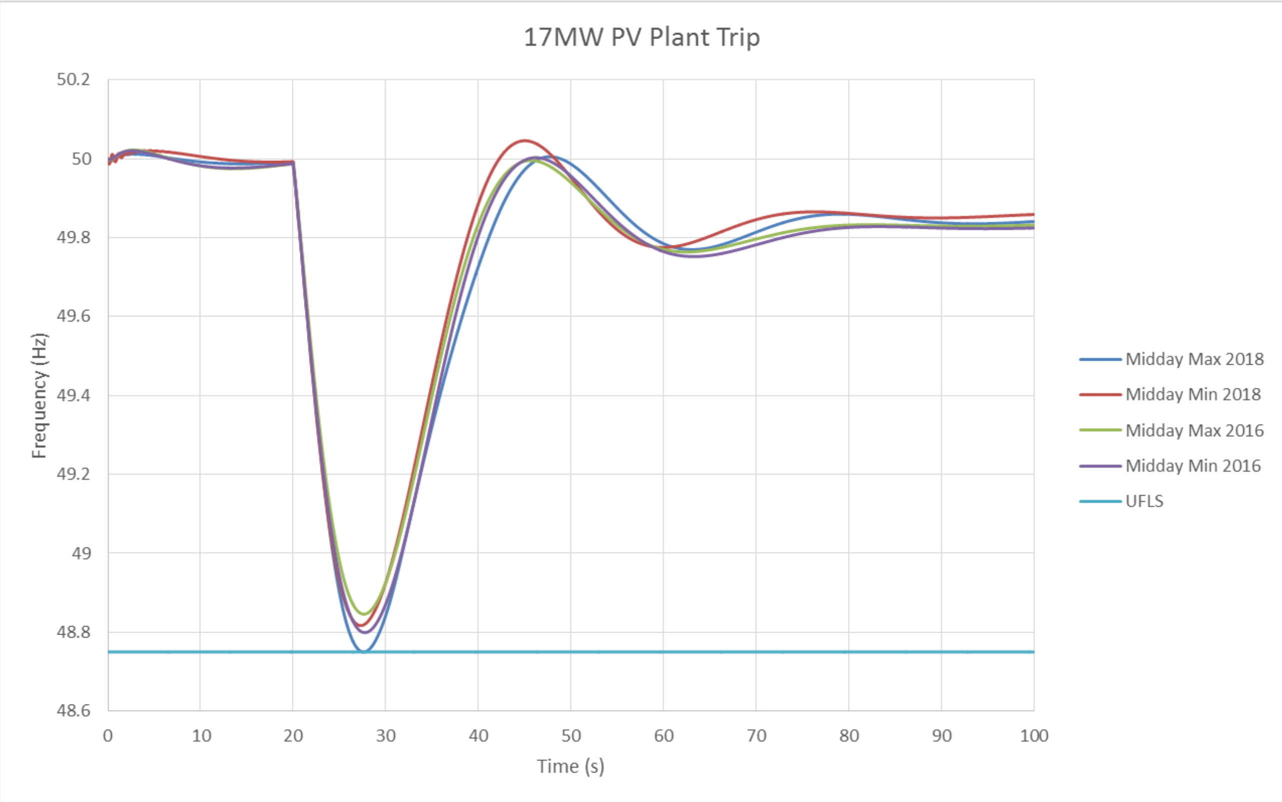


Figure 5.1: Comparison of system frequency response under different network scenarios

5.2 Effect of turning off Hydro Units 2016 midday minimum loading

System inertia as well as the reserve margin governing ability are the two most important factors in determining the frequency nadir after a plant trip. Generator units are switched off when the reserve margin is large enough in order to store water in the inlet pools of the power stations. The simulation was carried out in order to study the effect of switching off generator units on the system frequency response after the trip of a 17MW PV plant.

Figure 5.2 shows that after a single unit of both Nkula A and Tedzani 3 are turned off, the frequency breaches the under-frequency load shedding (UFLS) limit but not long enough (there is a four (4) second delay) to induce UFLS.

The UFLS relays should be reconfigured to operate instantaneously to improve system frequency recovery.

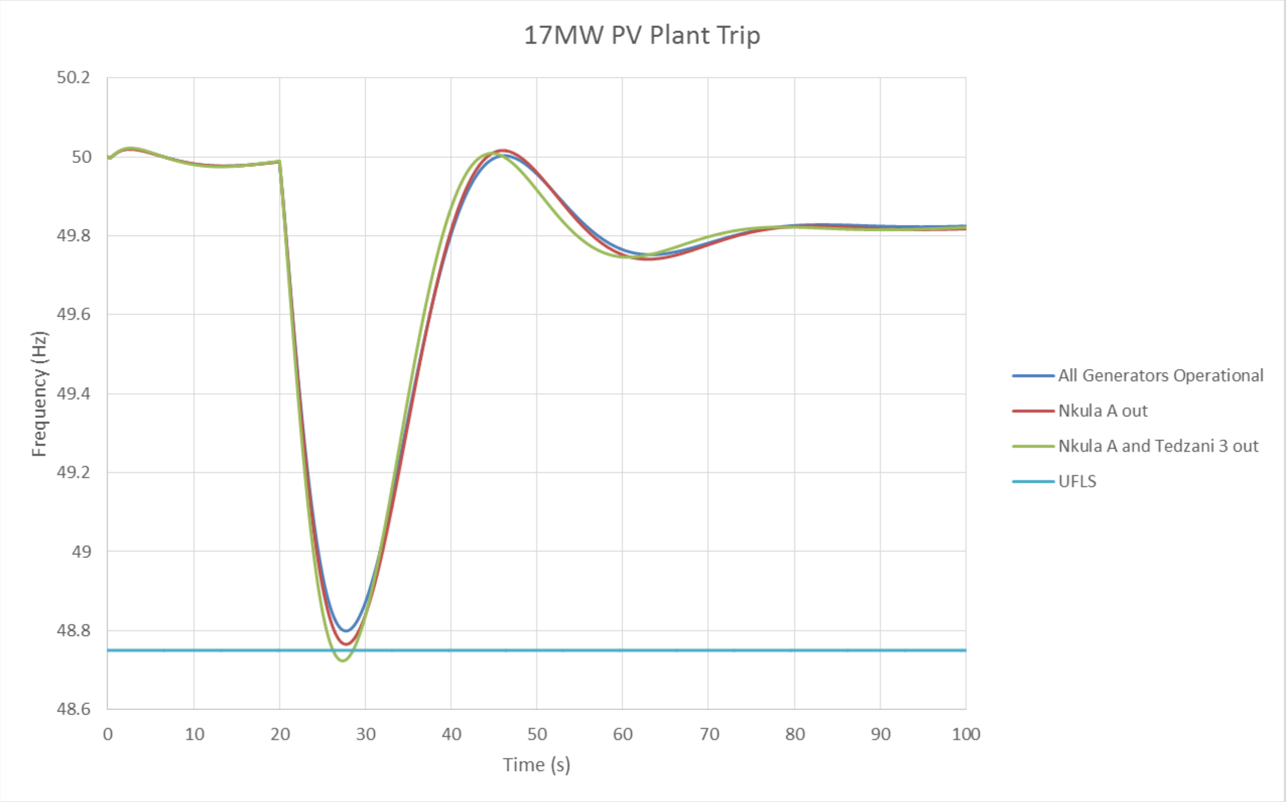


Figure 5.2: Effect of switching off generation units on system frequency response - 2016 midday minimum loading

5.3 Effect of turning of Hydro Units 2018

Similarly to section 5.2 above, the simulation was carried out in order to study the effect of switching off generator units on the system frequency response after the trip of a 17MW PV plant for 2018 midday maximum.

Figure 5.3 shows that after a single unit at Nkula A, the frequency breaches the UFLS limit but not long enough (there is a four (4) second delay) to induce UFLS. The slower frequency recovery is due to the in service governors reaching their control limitations.

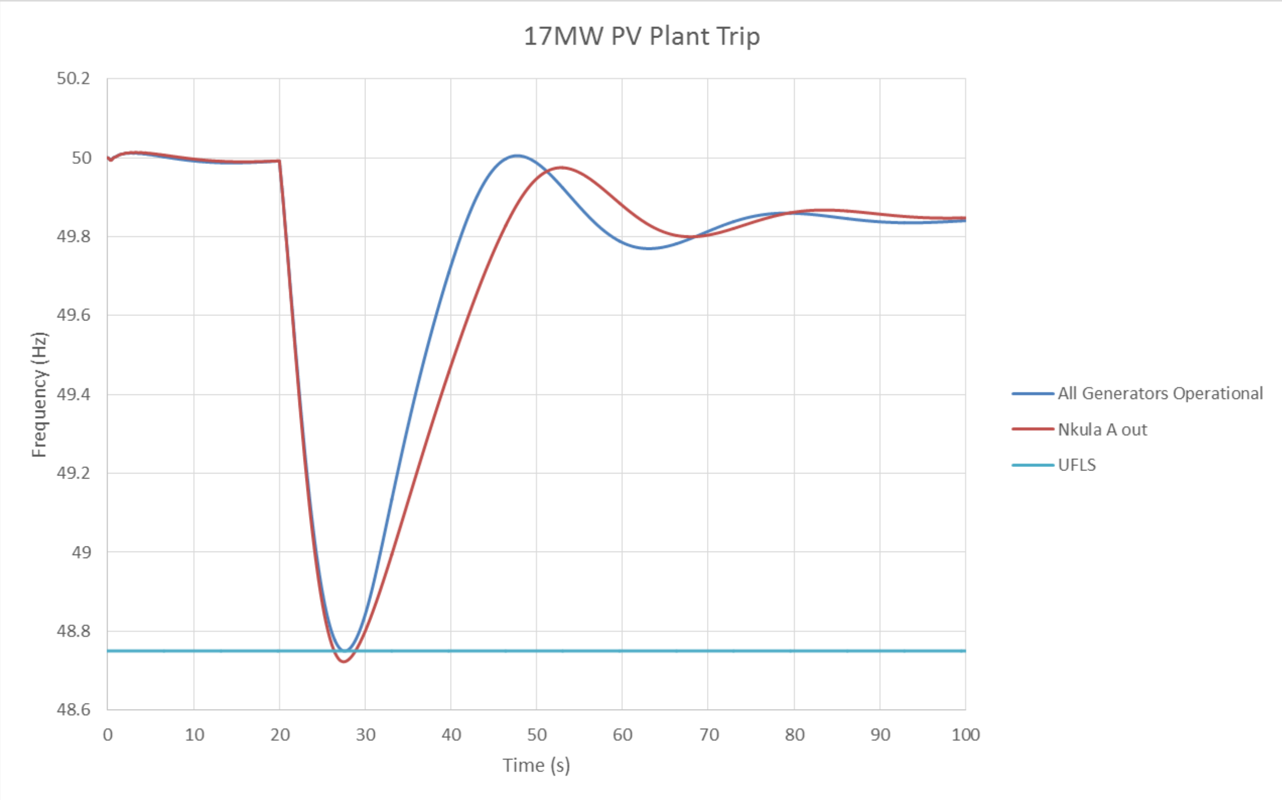


Figure 5.3: Effect of switching off generation units on system frequency response - 2018 midday maximum loading

5.4 Effect of additional PV plants 2016

An important output from this study is to determine how many PV plants can be installed. It was determined in Section 5.1 that a maximum of 17MW can be lost at one time and this simulation determines the effect of adding additional PV capacity in 17MW increments. In the 2016 midday minimum scenario the simulation was carried out with a single unit at both Nkula A and Tedzani 3 out of service as this represents the observed normal operational protocol.

Figure 5.4 shows that when additional PV generation is added, there is an initial drop in the frequency nadir, however this remains constant as further generation is added. The drop in the frequency minima is not enough to induce UFLS.

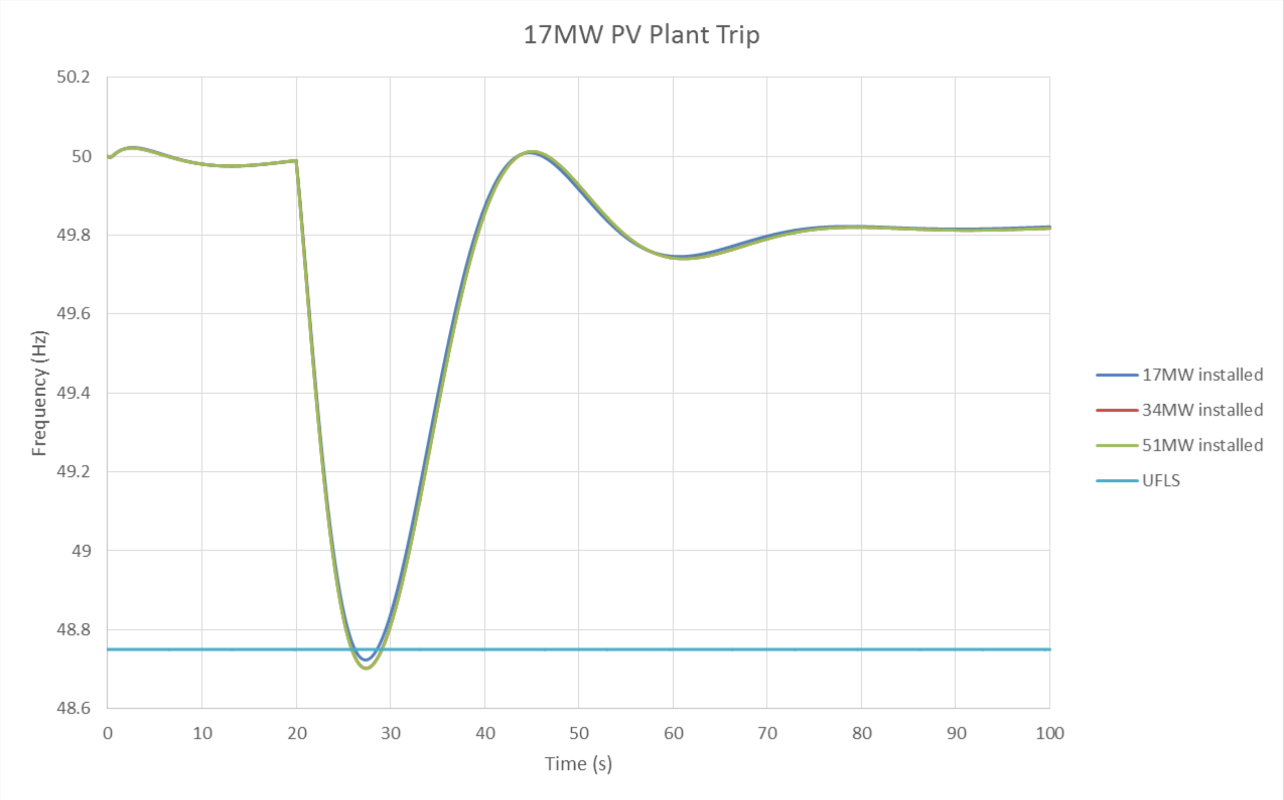


Figure 5.4: Effect of adding PV capacity on system frequency response - 2016 midday minimum loading

5.5 Effect of additional PV plants 2018

In 2018 midday maximum, the simulation was carried out with a single unit at Nkula A out of service.

Figure 5.5 shows that when additional PV generation is added, both the frequency nadir as well as the frequency recovery time improves. This is due to the PV plants offsetting power produced at the hydro stations which can in turn provide additional spinning reserve with governing capability. In the 17MW case, some of the generator units are already operating at maximum output, effectively removing their governing capability and slowing down the overall frequency recovery time.

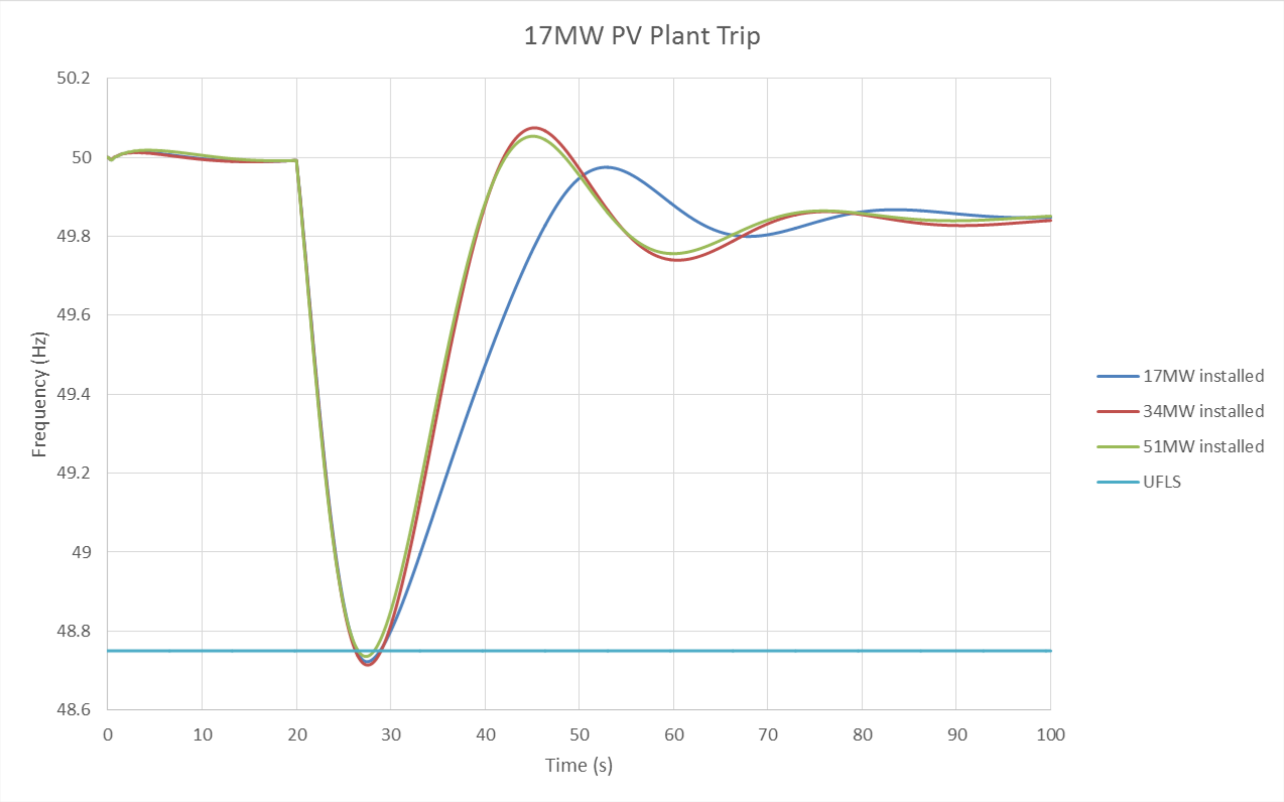


Figure 5.5: Effect of adding PV capacity on system frequency response - 2018 midday maximum loading

5.6 Effect having PV plant in the northern region

The previous sections have considered the frequency response after losing a PV plant in the meshed area of the network. It is important to investigate the effect of losing a PV plant in the northern region of the network which is radial in nature. In this case the network not only loses the generation from the PV plant but also a significant amount of system loss reduction caused by locating the plant near distant loads. Therefore it is expected that the maximum unit size in the northern region will be smaller than that in the meshed grid.

The following scenarios were used for the simulations below:

- 2016 midday minimum: a single unit at both Nkula A and Tedzani III is out of service
- 2018 midday maximum: a single unit at Nkula A is out of service

Figure 5.6 presents the frequency response during midday minimum loading in 2016. The results show that up to 16MW can be tripped in the radial northern region of the network. The frequency dips below 48.75Hz but for less than four (4) seconds and UFLS is narrowly avoided. It is therefore recommended that a safer limit of 15MW is set.

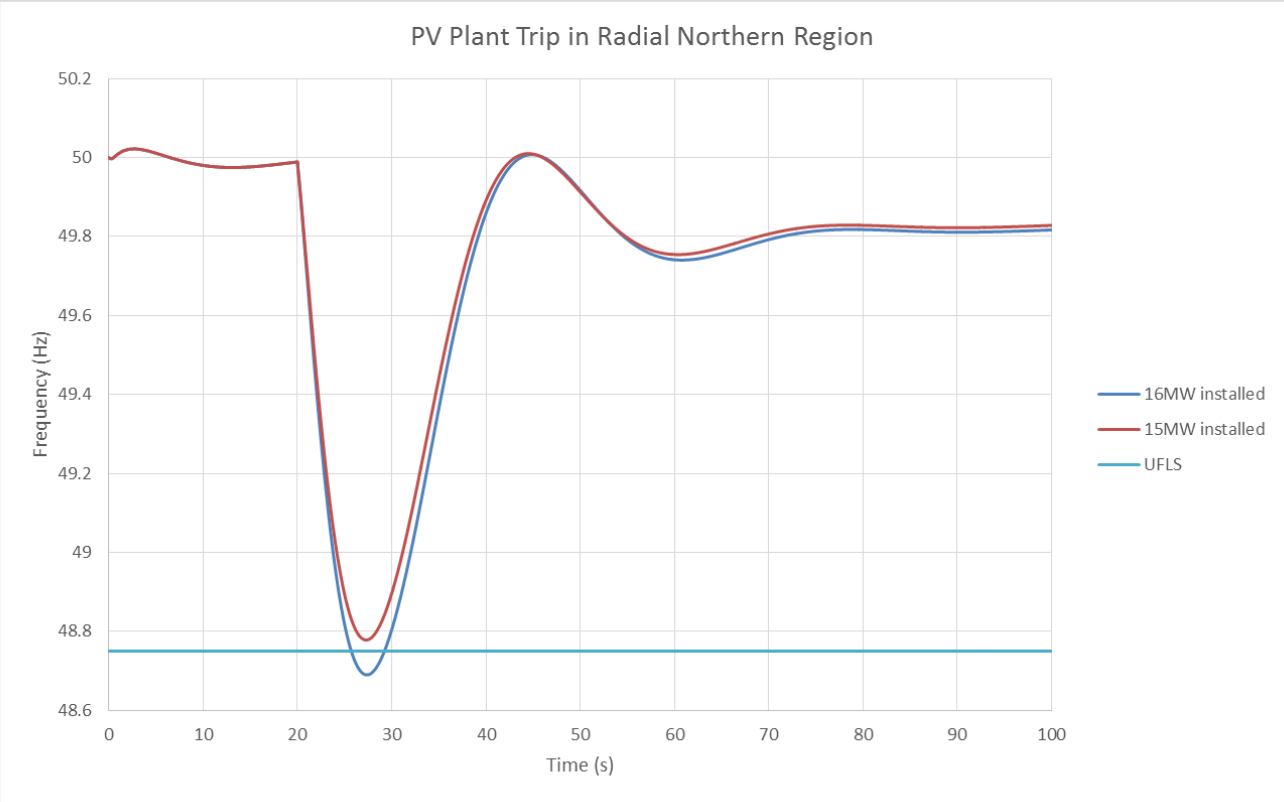


Figure 5.6: 2016 Min Midday comparison of system frequency response for different PV plant sizes in radial northern region

Figure 5.7 presents the frequency response during midday maximum loading in 2018. For the same unit size trips, the frequency deviates less than the 2016 simulation. This is due to the additional infrastructure which has been installed, reducing system losses, especially in the radial northern region.

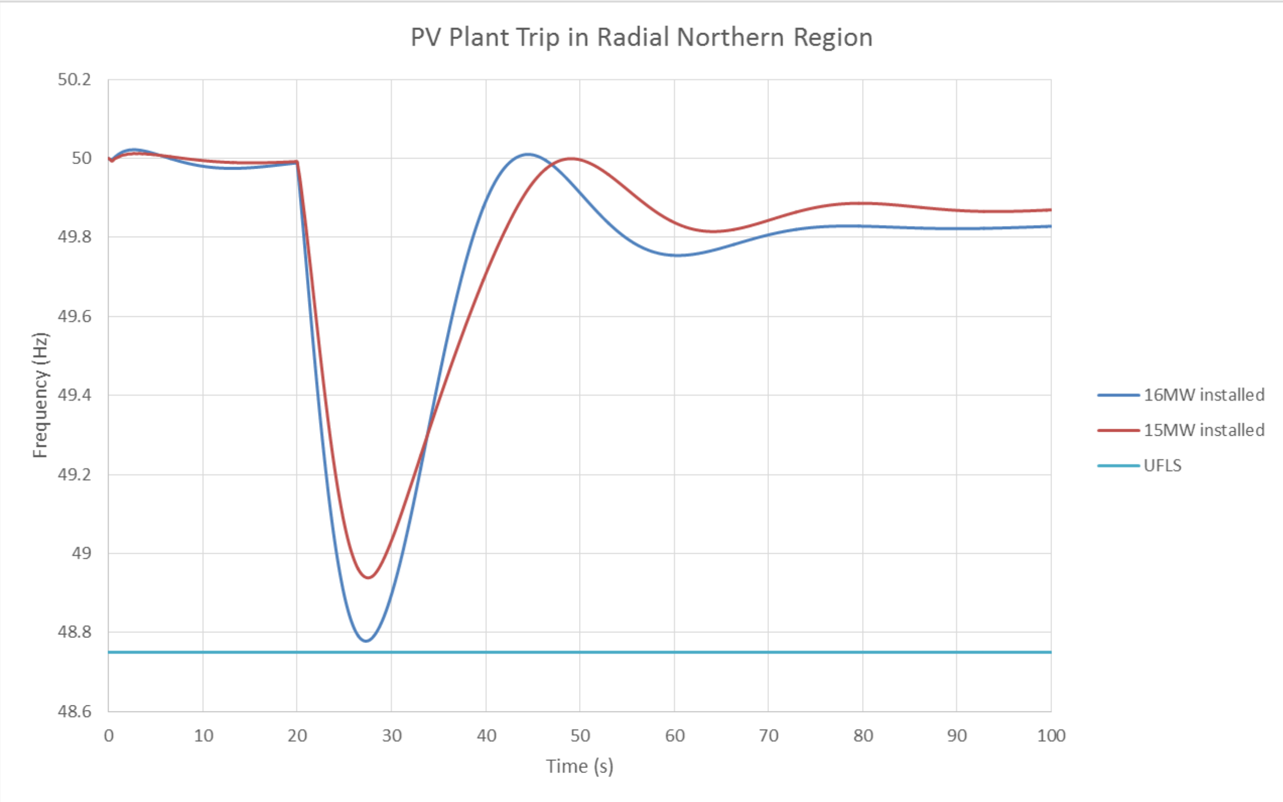


Figure 5.7: 2018 Max Midday comparison of system frequency response for different PV plant sizes in radial northern region

5.7 1-Minute Frequency Studies

The 1-minute deviation study determines the maximum 1-minute deviation due to the intermittency of installed variable generation. The generation output is decreased to 20% of its rated power over a 1-minute time period which represents the maximum possible 1-minute deviation for 1 plant under normal operating conditions. The study was carried out for 2018 only as it represents the worst case frequency response scenario. In Section 6, the 1-minute deviation of PV plants is discussed.

The study indicated that in order to avoid invoking UFLS, the maximum 1-minute variation is 70MW. This represents the maximum amount of power which can be lost due to clouds moving over the installed PV plants over the period of 1-minute. As mentioned, this is based on the assumption that there is no additional load from current system loadings (2016, 2018) and that existing hydro generation is curtailed (with a minimum of 70MW reserve) when the PV plants are in operation.

It is recommended that no more than 70MW of PV is installed initially. Although this is a conservative number, it will help keep the system stable when unplanned generator outages coincide with highly variable solar radiation (overcast conditions). It should be noted that under any condition only a single unit at both Nkula A and Tedzani III may be out of service or an equivalent combination in terms of inertia and governing ability. If these restrictions are not adhered to, there is a chance that UFLS will be needed in the case of a PV plant trip.

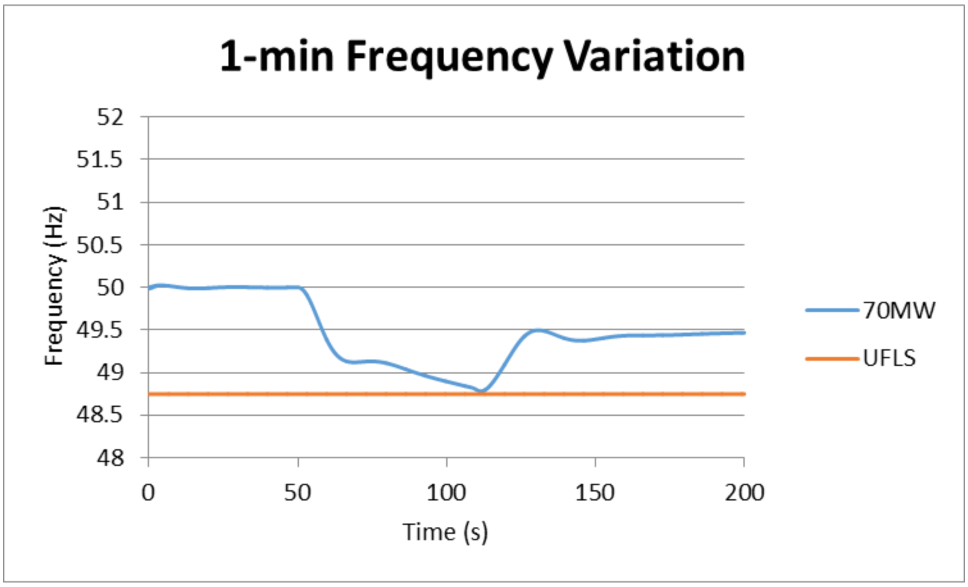


Figure 5.8: 2018 Frequency response for 1-minute variations in PV output

5.8 Limitations on PV generation - summary

In summary, the results from the preceding sections impose the following limitations on any PV installed onto the ESCOM network before additional base load generation is added or the Mozambique – Malawi interconnector is completed. It also assumes that no additional load has been added (discussed in Appendix G).

Maximum unit size in meshed network: 17MW

Maximum unit size in radial northern network: 15MW

Maximum 1 – minute deviation due to cloud movement: 70MW

Maximum installed PV capacity: 70MW

6 PV Integration Analysis

6.1 Probabilistic/geographical analysis of PV power plants

Figure 6.1 [1] below shows the long-term average Direct Normal Solar Irradiation in Malawi. It can be seen that high irradiation levels are predominantly in the central-lake and northern regions of Malawi. Moderate to high irradiation levels are well dispersed throughout the country.

The geographically wide spread high levels of radiation is a positive finding in terms of the probability of losing large amounts of PV generation due to localised cloud movements. In other words, if 100MW of solar PV generation were installed across the country in e.g. 10MW increments, the likelihood of a sudden loss of all 100MW of PV generation is very small.

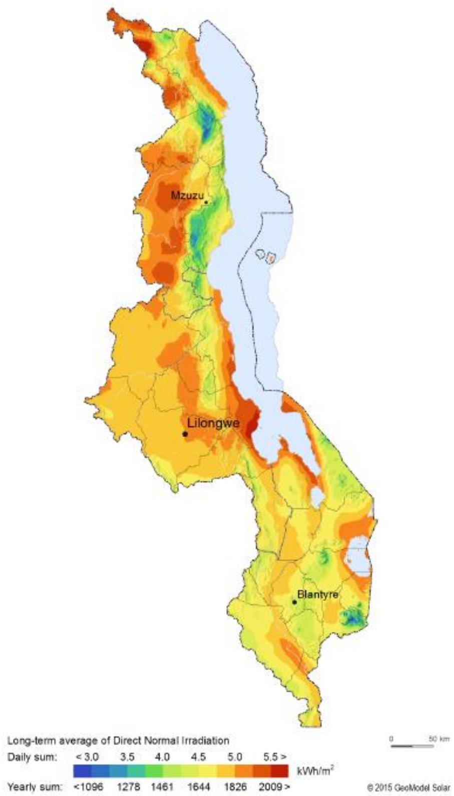


Figure 6.1 – Malawi Long-term average of Direct Normal Irradiation solar map [1]

There are many studies that have been carried out on the smoothing effect of geographical distribution on the power output of variable generation [2] [3] [4] [5] [6].

For example Mills and Wiser [2] indicate that a single plant can have an 80% unavailability (or variation) over one (1) minute intervals. Five (5) PV plants in close proximity have only a 40% variation and twenty three (23) PV plants distributed over a 400 square kilometre area can have only a 20% variation of available power. Based on these values, we use their method of calculating the maximum expected variation for a number of uncorrelated plants (more than 20 km apart [2]), and given in the equation below.

$$r \propto \frac{1}{\sqrt{N}}$$

Where *r* is the deviation from the maximum available power in per unit and *N* is the number of uncorrelated plants. Figure 6.2 presents the above formula graphically for up to 21 plants.

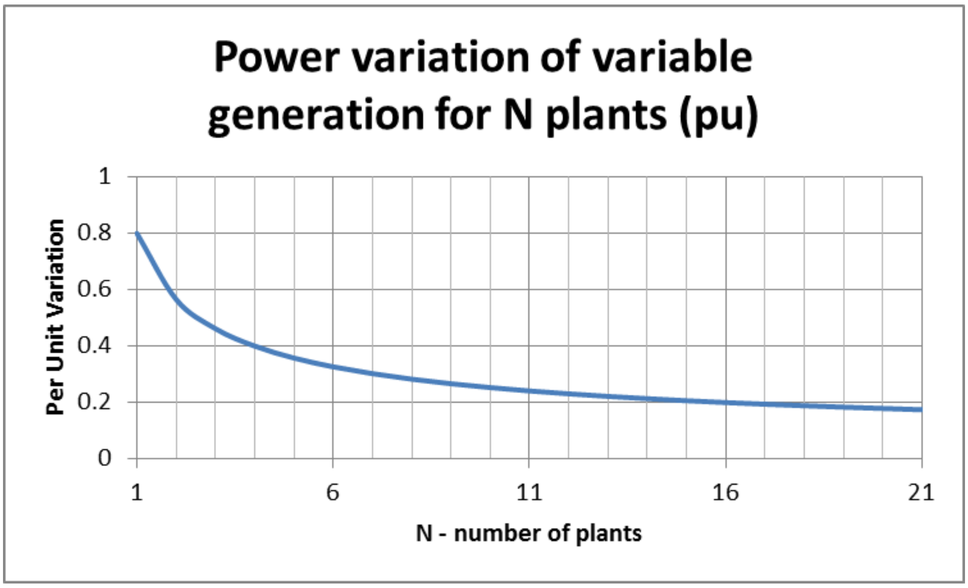


Figure 6.2: Per unit power variation on 1 min intervals for N number of plants

It follows that it is beneficial to have a higher number of small plants than fewer large plants to obtain a certain capacity goal.

6.2 Geographical location of PV plants

The technical limitations on where PV plants should be located are determined by the network topology, solar resources and system losses.

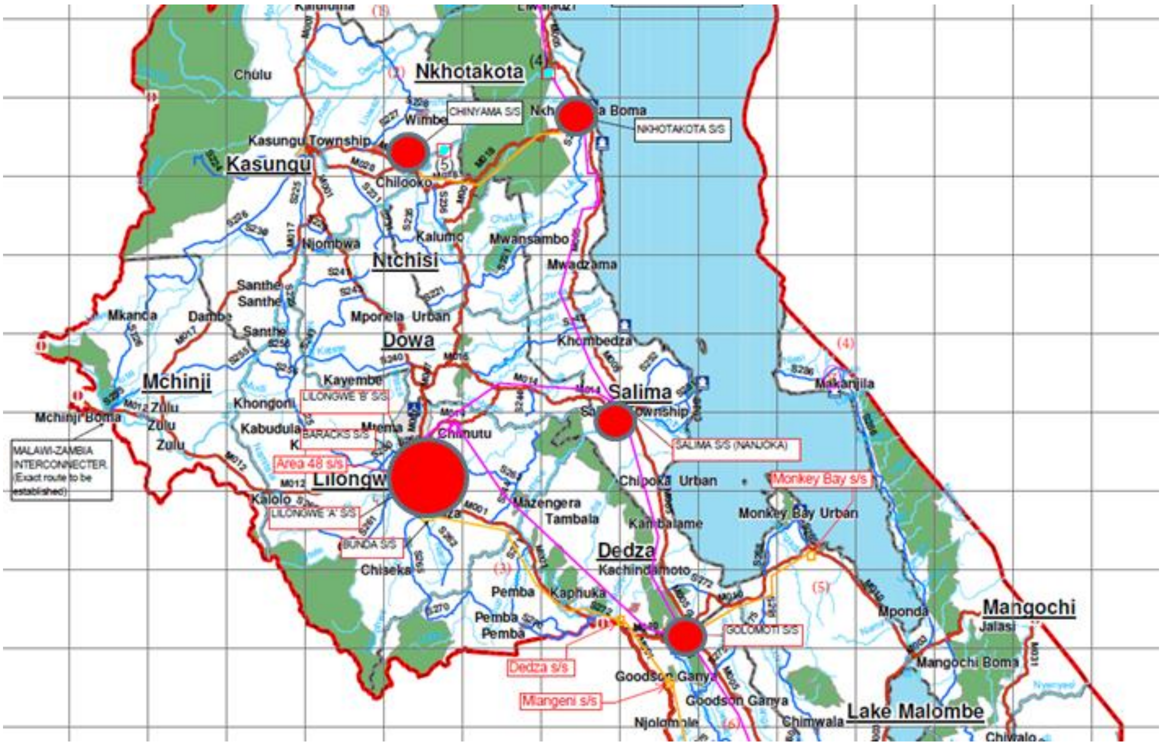
Based on both system losses and the solar resource map, it would be beneficial to have the plants installed near Lilongwe or in the Northern region, however the network should be able to recover from an N-1 contingency, limiting the amount of power that can be exported out of a radial part of the network to 15MW (from 2016 frequency response results).

Due to the limited load available in the radial northern region (27MW at mid-day peak in 2016), no more than two 15MW plants should be installed from Nkhotakota, northwards. In the case of losing the radial Nanjoka - Nkhotakota 132kV line, the total loss of generation would be less than 15MW.

A similar scenario occurs at Mulambe in the south of Malawi, where due to the local load and the radial 132kV line connecting it to Kapichira, only 1 plant of 15MW can be installed. In addition to this, the southern location provides minimal loss reduction as well as inferior conditions for PV plants in comparison to other regions.

The balance of the transmission system is well meshed resulting in lower restrictions on the amount of power which can be installed in the Southern and Central areas.

The figures below illustrate potential areas for integrating PV plants.




Chitipa Boma
Chitipa s/s
Mwenemisuku
Mwakaboko
Kilupula
Chitipa
Chisenga
Karonga s/s
Karonga Town
Mwenewenya
Karonga
Mwirang'ombe
Nthalire
Wovwe s/s
Uliwa s/s
Chilumba
Wasambo
Livingstonia s/s
Mwalweni
Mwalweni
Rumphi
Mwahenga
Jaravikuba Munthali
BWENGU S/S
Mtwalo
Musisya
Mpherembe
LUWINGA S/S
Mbalachanda
Mtwalo
Lupaso
Nyaluwanga
Euthini
Mtwalo
TEL. HILL S/S
Nkhata Bay Boma
Nkhata Bay
Mzimba
Lake malawi
Chikangawa s/s
Sibande
CHINTHECHE S/S
Mzimba Boma
Edingeni
Mkumpa
Embangweni
Dwambazi
Kafuzila
Mabulabo

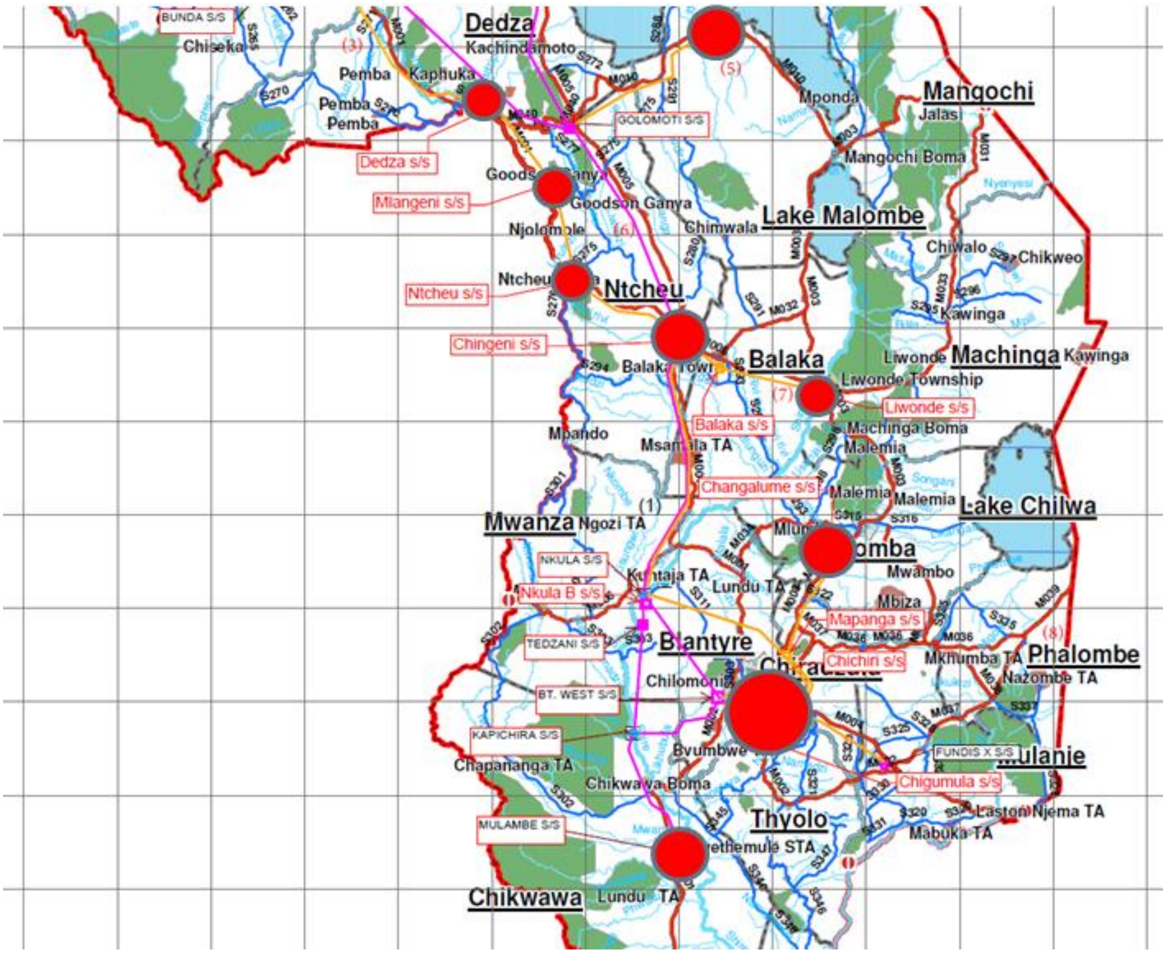


Table 6.1 below illustrates a ranked order for installing PV generation including the effect on system losses. The sites were selected considering local load as well as distance from the centralised generation located near Blantyre. The reduced effect on system losses in 2018 is due to the improved transmission infrastructure. It should be noted that the loss reduction values are for peak midday load and for one plant only

Table 6.1: Ranked order of PV integration

Notes	Busbar (66kV)	Size (MW)	2016 loss reduction	2018 loss reduction
One of the following	T/Hill	15	4.83	3.45
	Chikangawa	15	3.97	3.2
	Chintheche	15	4.2	3.73
	Nkhotakota	15	3.11	2.57
-	Dedza	17	3.76	1.93
One of the following	T/Hill	15	4.83	3.45
	Chikangawa	15	3.97	3.2
	Chintheche	15	4.2	3.73
	Nkhotakota	15	3.11	2.57
In any order	Barracks	17	2.57	1.14
	Area 48	17	2.85	1.22

The effect on losses of installing multiple plants is illustrated in Table 6.2. For illustrative purposes, the PV plants were added in the following order:

1. Chintheche
2. Dedza
3. Nkhotkota
4. Barracks

Table 6.2: Step-wise Integration of PV plants

Number of installed plants	Installed Capacity (MW)	2016 loss reduction	2018 loss reduction
1	15	4.83	3.45
2	32	8.38	5.41
3	47	9.98	6.37
4	64	11.55	7.01

Once again, the reduced effect on system losses in 2018 is due to the improved transmission infrastructure. In 2016 the transmission losses are almost halved after integrating 4 PV plants which nearly represents an entire PV plant on its own.

6.3 Short-Circuit Analysis

A short circuit analysis was carried out using the IEC60909 method. The base case fault levels are generally low as Table 6.3 illustrates. The fault levels, increase in 2018 as expected due to the newly installed transmission infrastructure.

Table 6.3: Base Case Fault Levels

Busbar	2016 fault level (kA)	2018 fault level (kA)
Chintheche	0.852	0.958
Nkhotakota	0.887	0.980
Dedza	0.499	1.450
Barracks	1.880	3.245

Table 6.4 presents the fault levels after integration of the 5 PV plants. After integration there is a small increase in fault level but the values are still well within standard circuit breaker ratings.

Table 6.4: Fault Levels after integration of PV plants

Busbar	2016 fault level (kA)	2018 fault level (kA)
Chintheche	1.135	1.226
Nkhotakota	1.181	1.255
Dedza	0.71	1.691
Barracks	2.301	3.710

7 Peaking Plant Analysis

The very low reserve margins observed at system peak in Malawi can be aided by generation that is designed to be on standby during this period. This section presents the effect of diesel peaking plants on the power system.

7.1 Assumptions

- Only the 132kV network busbars are considered
- Only maximum load is considered, because peaking should not operate under any other condition
- The maximum demands are as follows:
  - 2016: ***303MW***
  - 2018: ***327MW***
- The MEC is not allowed to exceed the total system load

7.2 Export Capacity

The export capacity was assessed at system peak for 2018 at 132kV busbars. The resulting values are similar in both 2016 and 2018 and are well over the maximum unit sizing of 17MW. The MEC at the various points in the network for 2018 maximum system loading are as follows:

Table 7.1: 2018 Peak load Transmission 132kV results

Busbar	Voltage	Voltage Control MEC (MW)	Limit
BT West	132kV	250	Voltage
Chintheche	132kV	94	Thermal
Golomoti	132kV	300	Load Limit
Kanengo	132kV	300	Load Limit
Luwinga	132kV	94	Thermal
Mlambe	132kV	115	Thermal
Nanjoka	132kV	230	Thermal
New Bwengu	132kV	94	Thermal
Nkhoma	132kV	300	Load Limit
Nkhotakota	132kV	107	Thermal
Phombeya	132kV	300	Load Limit

7.3 Unit Sizing and Location

The maximum unit sizes can be would be the same as the maximum PV unit size (17MW in meshed network and 15MW in radial northern network) with the limiting factor being frequency stability.

Any peaking plants installed should be integrated on part of the meshed transmission system and not on a radial line. This is to ensure greater system security during the critical peak loading hours. As a study scenario, the Nanjoka substation along with the Golomoti - Nanjoka contingency represents the worst-case in terms of transient stability. Within the meshed portion of the transmission system, the frequency response is similar at all substations.

7.4 Frequency Response

Figure 7.1 and Figure 7.2 below illustrate the positive effect of diesel generation on the frequency response of the system after tripping a unit of Nkula A. For the simulation, it is assumed that any diesel generators are operating at approximately 50% of their capacity and that no extra load has been added. The diesel governor and AVR are modelled using standard DEGOV and IEEET1 models. The improvement in the base case result of 2018 vs 2016 is due to newly installed diesel generation being available at Mzuzu and Kanengo. It should be noted that diesel plants running at 50% are fairly inefficient and this has only been used for illustrative purposes.

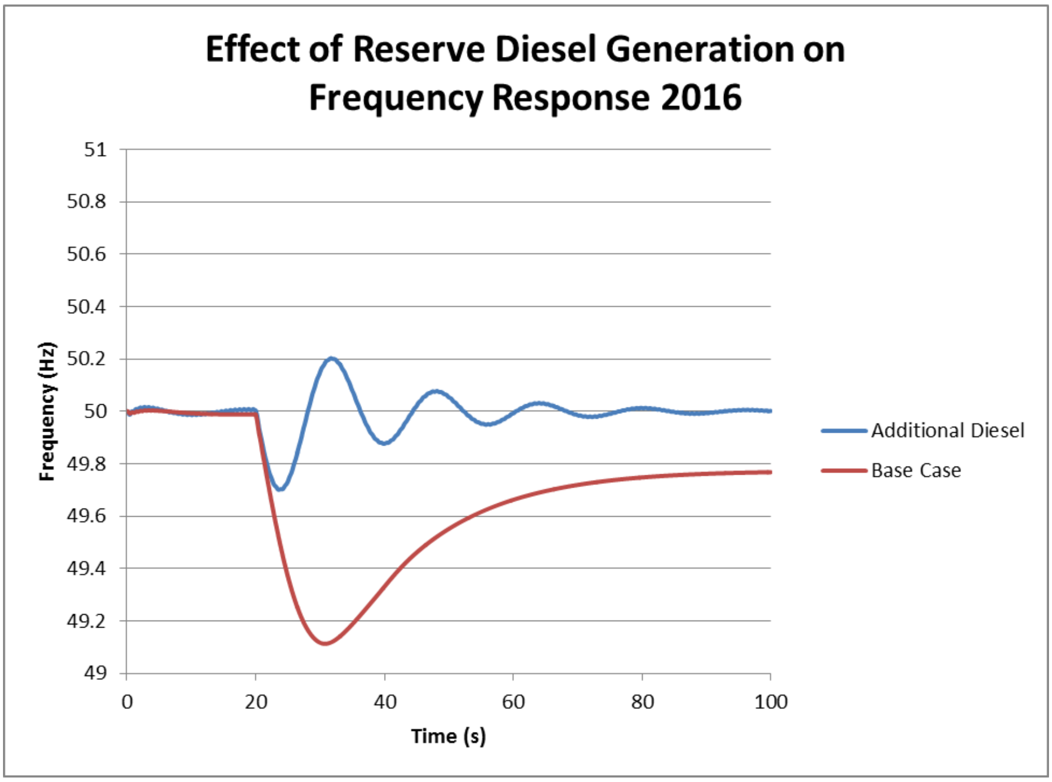


Figure 7.1: 2016 Frequency Response with additional peaking diesel generation

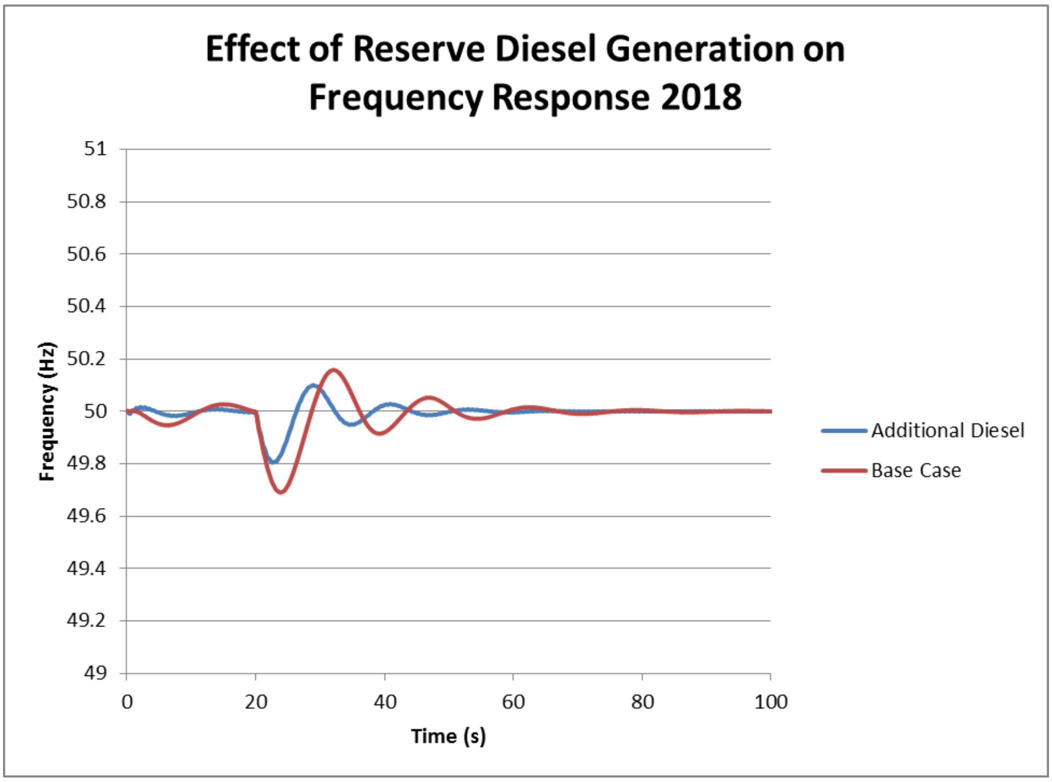


Figure 7.2: 2018 Frequency Response with additional peaking diesel generation

7.5 Transient Stability

The transient stability of the peaking diesel generator is assessed by causing a fault and tripping the Golomoti – Nanjoka 132kV line after 100ms. This has the effect of moving the diesel generator electrically further from the generation centre in Blantyre changing the power angle. Figure 7.3 and Figure 7.4 below illustrate this with an increase in the generator rotor angle after the contingency. In 2018, an oscillation is observed in the rotor angle after the contingency. This is due to the Mzuzu diesel generator oscillating and if turned off, the oscillations are removed. It should be noted that although oscillations are observed, the system is still transiently stable. The oscillations can be corrected by tuning the AVR or applying a Power System Stabiliser.

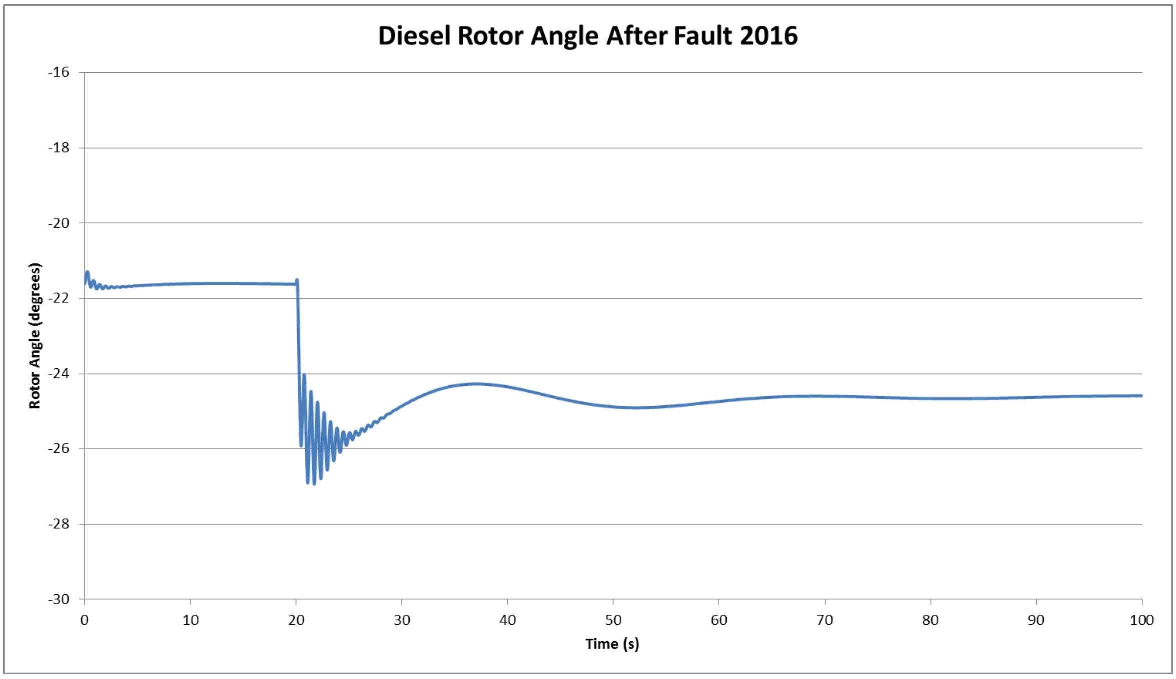


Figure 7.3: 2016 Transient stability with additional peaking diesel generation

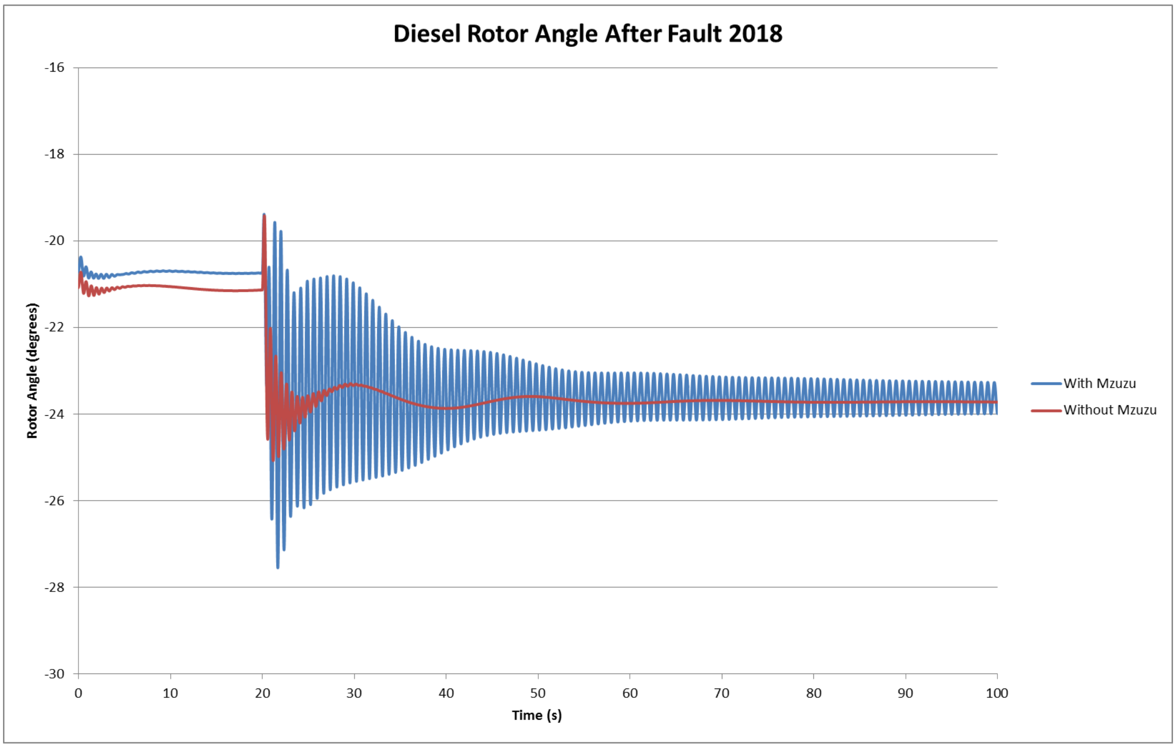


Figure 7.4: 2018 Transient stability with additional peaking diesel generation

8 Base Load Analysis

In addition to peaking plants the effect of base load plants need to be investigated on the islanded Malawi system. Thermal base load plants can provide fast governing reserve as well as allowing additional load to be added to the system. This section determines the effect of base load plants on the power system.

8.1 Assumptions

- Only the 132kV network busbars are considered
- Only minimum load is considered for the MEC as this represents the worst case
- The minimum demands are as follows:
  - 2018: ***170MW***
- The MEC is not allowed to exceed the total system load

8.2 Export Capacity

The export capacity was assessed at system minimum for 2018 at 132kV busbars. Only the 132kV network was assessed in order to give an indication of the areas export capacity. Only 2018 needs to be assessed due to the long lead times for base load thermal projects.

The 2018 system minimum loading MEC at various points in the network are as follows:

Table 8.1: 2018 Minimum load Transmission 132kV results

Busbar	Voltage	Voltage Control MEC (MW)	Limit
BT West	132kV	150	Load Limit
Chintheche	132kV	90	Thermal
Golomoti	132kV	150	Load Limit
Kanengo	132kV	150	Load Limit
Luwinga	132kV	90	Thermal
Mlambe	132kV	110	Thermal
Nanjoka	132kV	150	Load Limit
New Bwengu	132kV	90	Thermal
Nkhoma	132kV	150	Load Limit
Nkhotakota	132kV	95	Thermal
Phombeya	132kV	150	Load Limit

8.3 Unit Sizing and Location

A large amount of power can be produced from multiple thermal base load units however, without spinning reserve that is faster than the current hydro based system, the unit sizes are limited. Therefore any thermal IPP that connects to the ESCOM network will need to contribute to spinning reserve in order to allow larger units (which are far more efficient) to trip as a N-1 contingency before under frequency load shedding (UFLS) is invoked. Similarly to peaking plants, base load should be integrated in a meshed part of the Transmission system to ensure maximum security.

As an example, Figure 8.1 shows the frequency response after tripping one (1) of four (4) 30MW units running at 26MW each at Nanjoka. This represents a power station totalling 120MW, dispatched at 104MW. It can be seen that UFLS is avoided at both maximum and minimum system loading. It should be noted that no extra load was added for this simulation and the exact amount of extra load which can be added to the system after installing base load plants like these needs to be studied carefully in order to ensure the correct reserve margins are kept at all times. Standard TGOV1 and IEEET1 models were used to model the governor and AVR respectively.

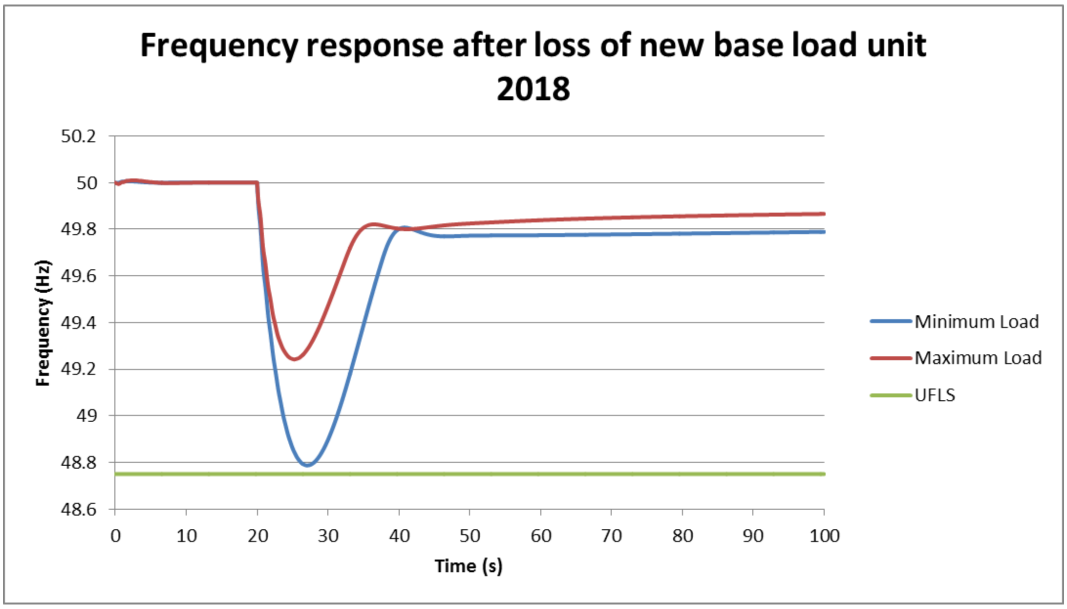


Figure 8.1: Frequency response after losing 1 of the 4, 30MW thermal base load units

8.4 Frequency Response

Figure 8.2 below illustrates the positive effect of thermal base load generation on the frequency response of the system after tripping a unit of Nkula A. For the simulation, it is assumed that all thermal units are operating at 26MW (of their 30MW capacity) and that no extra load has been added.

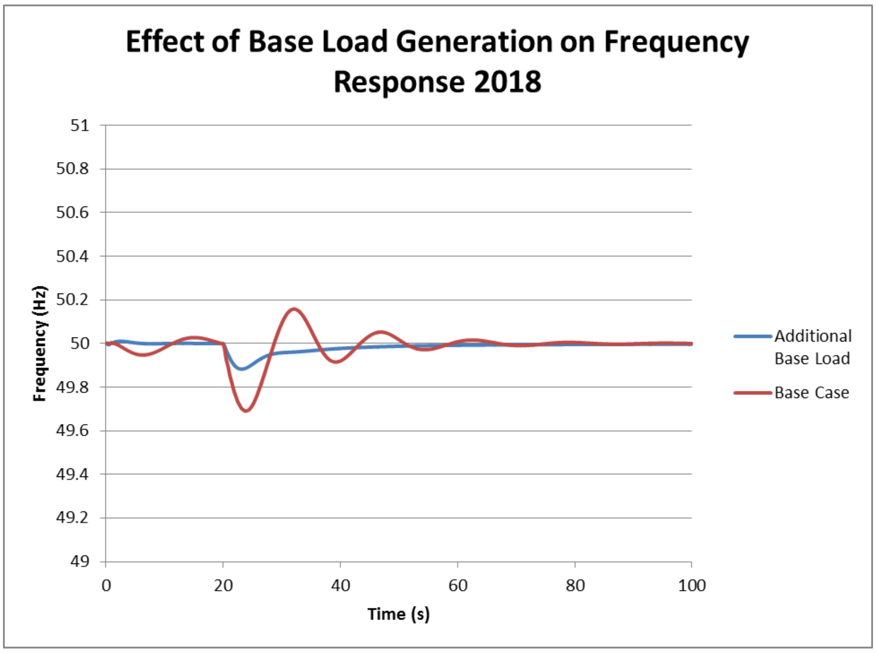


Figure 8.2: 2018 Frequency Response with additional base load thermal generation

8.5 Transient Stability

The transient stability of the thermal base load generators are assessed by causing a fault and tripping the Golomoti – Nanjoka 132kV line after 100ms. This has the effect of moving the generators electrically further from the generation centre in Blantyre, changing the power angle. Figure 8.3 below illustrate this with a slight increase in the generator rotor angle after an oscillation period. The new generation is transiently stable for the worst case contingency.

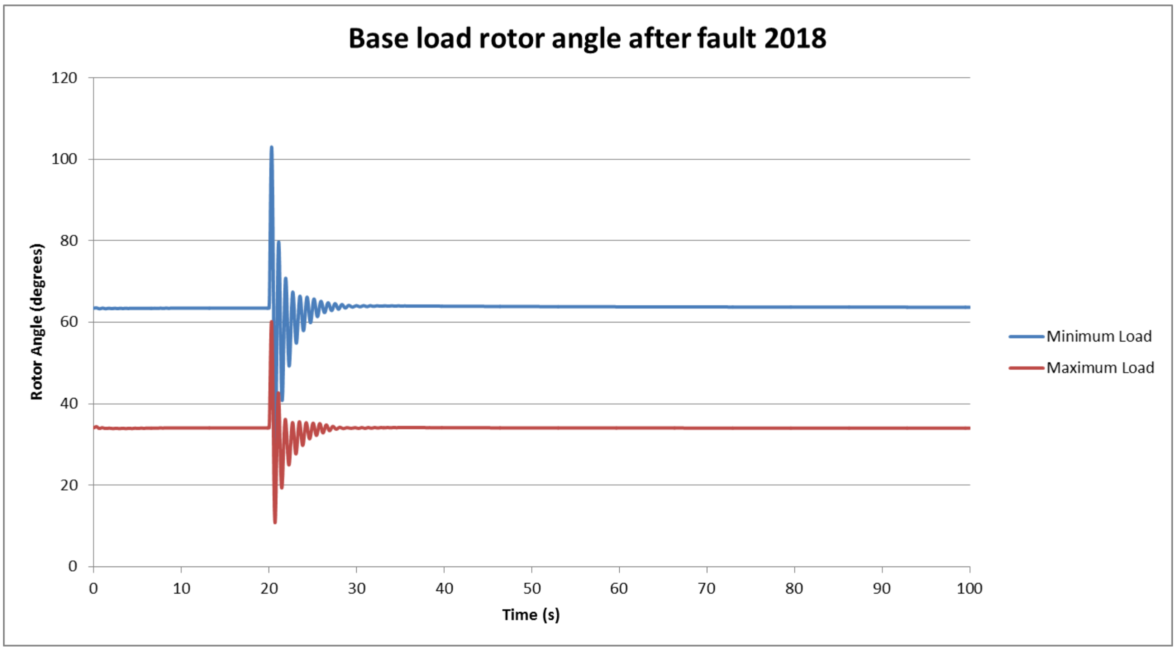


Figure 8.3: 2018 Transient stability with additional base load generation

9 Conclusions

The following conclusions are presented below.

Conclusions may change once system response curves are received from the power plants or once site measurements have taken place however on the basis of information collected so far, we feel the model provides a fair representation of what occurs on the system.

The conclusions are presented below.

1. Steady-State Analysis:
   - The load flow studies indicate that connections of 4MW to 300MW are possible from a steady state point of view at various busbars in the network.
   - System losses decrease by up to 20% after integration at some areas of the network. However, if the distributed generation exceeds local load, losses start to increase and even exceed previous levels in some cases.
2. Frequency Response Studies
   - Modified governor settings were found to provide good correlation with an actual Nkula A generator tip.
   - The limiting scenario for a PV connection in the meshed network is 17MW.
   - The limiting scenario for a PV connection in the radial northern network is 15MW.
3. PV integration Analysis
   - Although the northern system is suitable for PV connections from a system losses, geographical and network diversity point of view, it is limited in the amount of generation it can transfer due its radial nature especially for 2016 (a trip of the radial line disconnects northern PV plants from the bulk network).
   - Due to the meshed nature of the Southern and Central parts of the transmission system, larger increments of power can be connected on these networks.
   - With the assumed reserve margin, multiple uncorrelated (at least 20km apart) PV units can theoretically be connected across the system however it is recommended that this is initially limited to 70MW for system inertia and governing response reasons.
   - It should be noted that if PV is to be integrated, an operational project-specific study will need to be undertaken in order to determine the required amount of online units (for both inertial and governing purposes) under all possible conditions.
   - PV plants take up approximately 2 hectares per MW of land and this needs to be considered when positioning plants.
   - The overall study undertaken indicates that for all normal operating conditions up to 2018, a loss of a 17MW PV plant in the meshed system will not induce UFLS if only one (1) unit of Nkula A is offline. The same is true of 15MW in the radial northern system.
   - No additional load should be connected after the integration of PV plants. This is due to the fact that PV has a narrow mid-day generation band where maximum power is achievable and even then it is not guaranteed. Adding extra load will in fact decrease the existing small reserve margins (Appendix G), increasing the chance of invoking UFLS and decreasing system reliability.
4. Peaking Plant Analysis
   - Peaking plants should initially be limited to around 17MW in size
   - The plants should be integrated in a meshed area of the grid to increase the availability of the peaking plant and overall system security

- The peaking plant was found to improve the system frequency response (increased inertia and governing capability)
- The peaking plants will be transiently stable if integrated within the meshed system
- Peaking plants should only be run at system peak and not at any other time (for economic reasons)

5. Thermal Base Load Analysis
   - Base load plants need to provide some spinning reserve in order to allow larger units to be connected to the system (equipment prices, unit efficiency and economies of scale). An example is 4x30MW units all operating at 26MW.
   - As with the diesel peaking plants, the thermal plants should be integrated in a meshed area of the grid to increase system security
   - Thermal plants improve the system frequency response (inertial response and governing capability)
   - The plants will be transiently stable if integrated within the meshed system
   - Once an international interconnector is built, larger thermal units may be connected to the power system. This is because the SAPP system can then provide additional inertial response and governing capability

10 Recommendations

The following are recommendations based on findings and conclusions of this study:

11. Multiple 17MW PV power plants can be connected to the meshed network at system substations which meet the MEC requirements.
12. Multiple 15MW PV power plants can be connected to the radial northern network at system substations which meet the MEC requirements.
13. PV plants larger than 17MW can be installed if they are built and connected in such a way that a single contingency only removes 17/15MW from the system at a time. This can be achieved through multiple transmission lines and or transformers etc.
14. The total of installed PV should initially be limited to 70MW.
15. The UFLS relays should be reconfigured to operate instantaneously to improve system frequency recovery.
16. Operational studies should be carried out for each PV plant to be connected to ensure that there will always be enough system inertia and governing reserve to ride through a plant trip under all operational conditions.
17. PV power plants should be dispersed in the following manner:
    - Connected to different backbone transmission systems (e.g. northern system, Lilongwe system, Golomoti system, Salima system, various Blantyre systems) which creates electrical connection diversity
    - Connected in a geographically dispersed manner with electrical and weather diversity benefits
18. No Additional load should be connected to the ESCOM power system
19. If more load is to be serviced on the ESCOM power system, the following infrastructure should be prioritized:
    - <u>SAPP Interconnector</u> (emergency reserve, regulatory reserve, system inertia from the SAPP system, energy (kWh) when available from SAPP countries, diversity from hydro, export of Malawi PV kWh when available)
    - <u>Peaking HFO or Diesel plant</u> (already in the mini-IRP and makes sense for system peak). HFO has cheaper USc/kWh, fast frequency response but likely to be too expensive as spinning reserve for non-dispatchable PV during the day
    - <u>Baseload coal</u> (emergency reserve, regulatory reserve, kWh, diversity from hydro, fast frequency response) Probably 2 x 100MW units due to the size of the Malawi system versus cost savings in terms of unit size (economies of scale)
    - <u>Baseload gas</u> (emergency reserve, regulatory reserve, kWh, diversity from hydro, fast frequency response). If gas can be obtained at ~\$5/GJ to \$7/GJ, gas will likely be comparable to coal but a gas source needs to be found
    - <u>Solar PV</u> (kWh, non-dispatchable, can help with frequency response if output constrained, does not increase/improve system inertia). PV can decrease coal or gas input costs when sun shining (kWhs) but cannot be relied upon for capacity
    - <u>Hydro</u> (hydro is weather dependent and if poor rainfall all hydro generators equally affected). Malawi needs to diversify away from hydro until other baseload, interconnector or peak generation sources are in place

1. Although a Mini-IRP document has been developed by MERA in Malawi, a further refinement to this IRP should be considered taking into account demand forecasts, forecasted Load Duration Curves (LDCs), Shire River hydrology, competing generation capital and variable costs and planned imported/exported generation.

11 Works Cited

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[2] R. A.Mills, “Implications of Wide Area Geographic Diversity for Short-Term Variability of Solar Power,” 2010.

[3] A. K.Dragoon, “Solar PV Variability and Grid Integration,” 2010.

[4] T. A. R. C. J. R. M.Suri, “Cloud Cover Immpact on Photvoltaic Power Production in South Africa”.

[5] B. A. K. S.Shedd, “A Statistical Characterization of Solar Photovoltaic Power Variability at Small Timescales,” 2012.

[6] R. T.Hoff, “Predicting Short-Term Variability of High Penetration PV”.

Appendix A – Planned Transmission Projects and dates (source ESCOM)

ESCOM
Transmission and Substations Projects

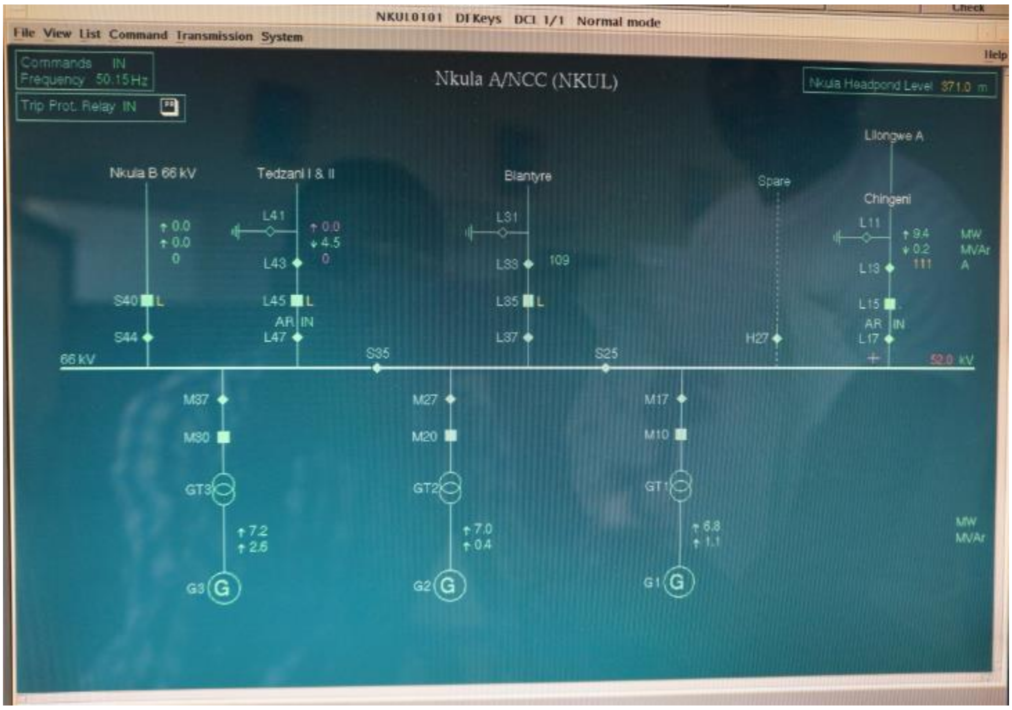
Project Name	Operating Voltage (kV)	Expected Commissioning year
Mozambique – Malawi Interconnection (Tete-Phombeya)	400	2019
Phombeya SS	400/132	2019
Phombeya – Nkhoma line	400	2018
400kV Malawi – Mozambique (extension)	400	2020
Malawi – Tanzania Interconnection (Nhkoma-Songwe-Tanzania)	400	2022
Zambia – Malawi Interconnection (Chipata - Nknoma)	330	2020
Nkhoma - Nanjoka (including trafo upgrade) – Nkhotakota – Dwangwa –Chintheche Line	132	2020
Nkhoma Substation	400/132/33	
New Dwangwa– Chatoloma Line	132	2020
New Blantyre substation	132/33kV	2020
New Phombeya – Kangankude – Machinga – Zomba	132	2020
Upgrade from 66kV to 132Kv Golomoti - Monkey bay Line	132	2020
132kV Nchalo – Nsanje	132	2020
Karonga – Kayerekera Line	132	2022
Nkhoma – Bwengu Line	400	2020
Blantyre West – Fundi's X – Mkango Line	132	2020
Phombeya – Makanjira Line	400	2020

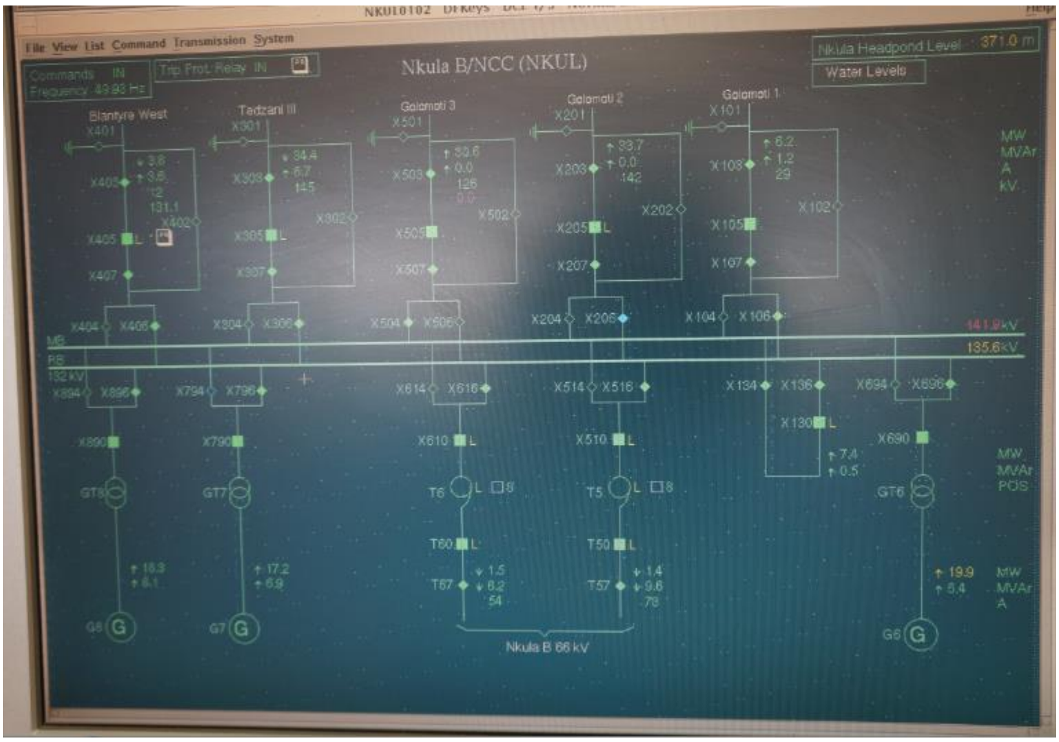
Appendix B – Under Frequency Load Shedding (UFLS) Feeders and trip times

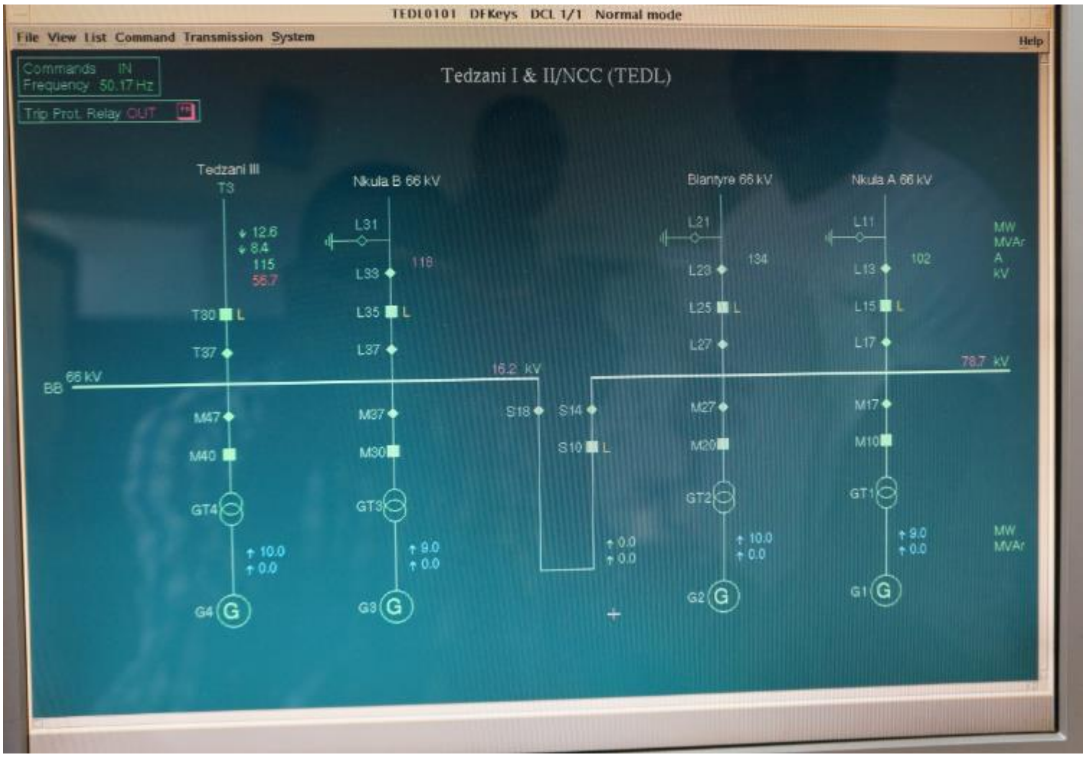
Minimum Load				Maximum Load (System Peak)			
	Time	01h30		Time	18:30		
Substation	U/F Feeder	Load (A)	MW	Substation	U/F Feeder	Load (A)	MW
Chichiri	105	90	5.142857	Chichiri	105	201	11.48571
Chichiri	405	141	8.057143	Chichiri	405	200	11.42857
BT West	H10	66	7.542857	BT West	H10	185	21.14286
Mapanga	L55	30	3.428571	Mapanga	L55	60	6.857143
Golomoti	T10	17	1.942857	Golomoti	T10	40	4.571429
Nanjoka	180	16	3.657143	Nanjoka	180	30	6.857143
LLB	L15	114	13.02857	LLB	L15	208	23.77143
LLB	L25	39	4.457143	LLB	L25	89	10.17143
LLB	305	64	3.657143	LLB	305	66	3.771429
LLB	7L5	130	2.47619	LLB	7L5	357	6.8
Chintheche	L35	16	1.828571	Chintheche	L35	53	6.057143

Substation	Feeder/Breaker	Settings	
		Time (s)	Freq. (Hz)
Chichiri/Blantyre	33 KV feeder 105	4	48.75
	33 KV feeder 405	4	48.75
Blantyre West	66/33 KV transformer T1 HV breaker VCB H10	4	48.75
Mapanga	66kV feeder L55	4	48.75
Kanengo	66kV feeder L15	4	48.75
	66kV feeder L25	4	48.75
	33kV feeder 305	4	48.75
	11kV feeder 7L5	4	48.75
Golomoti	132/66/33kV Transformer T1 LV breaker T10	8	48.75
Salima	Transformer T1 LV breaker GCB 180	4	48.75
Chintheche	66 KV breaker L35	8	48.75

Appendix C – System Snapshots from NCC



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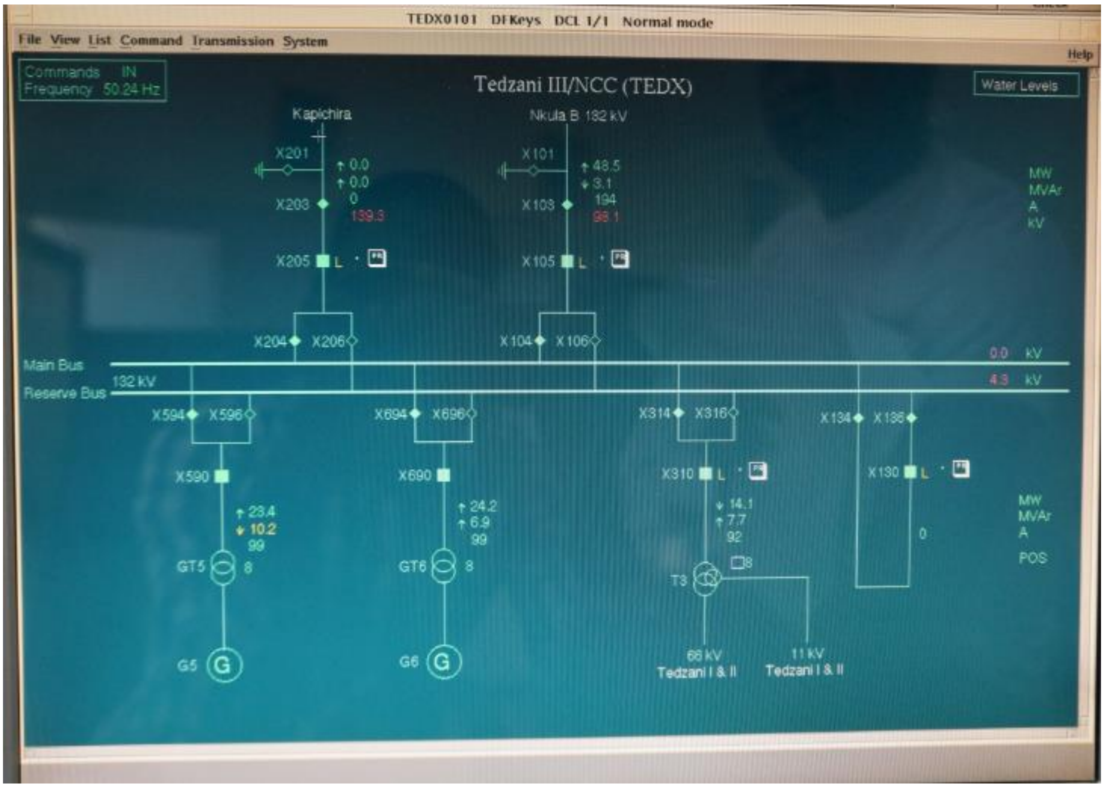
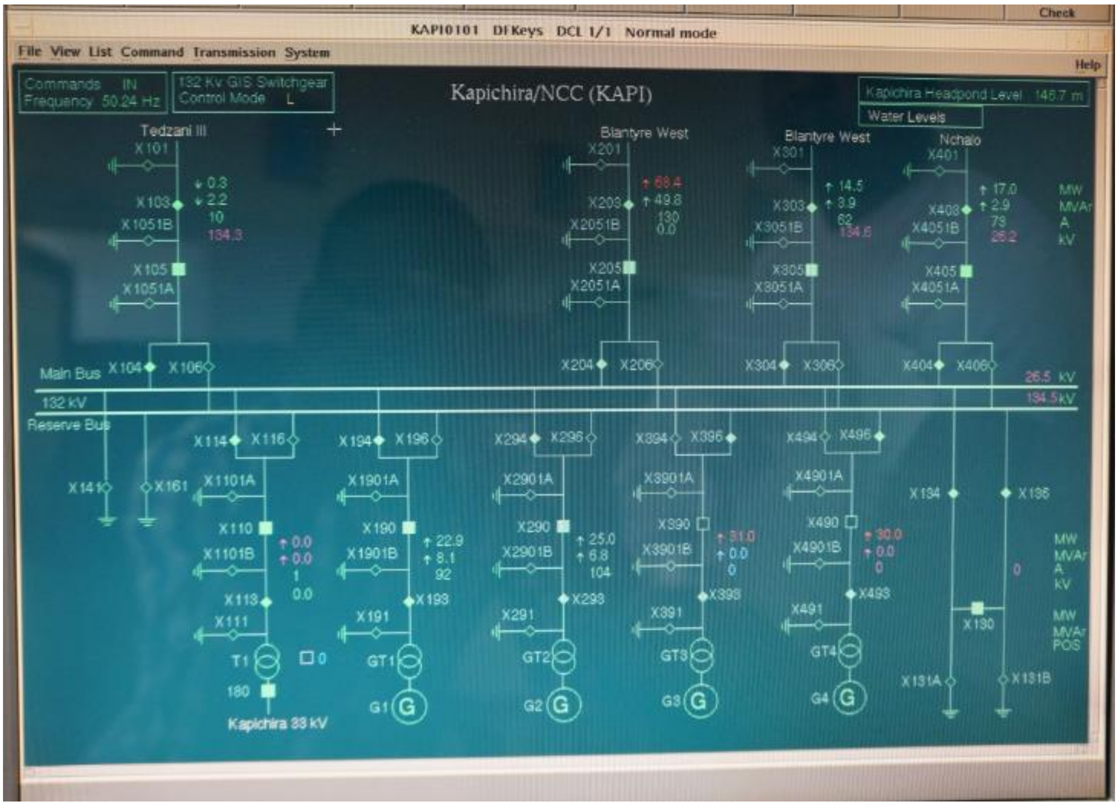
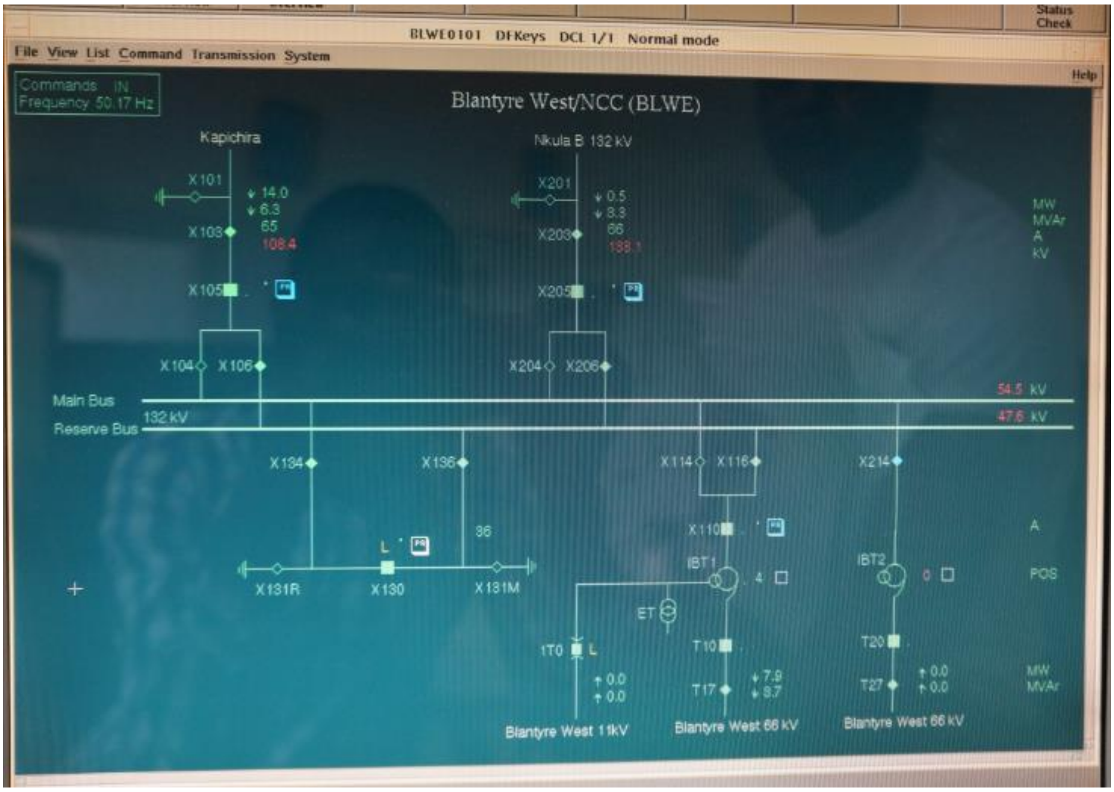
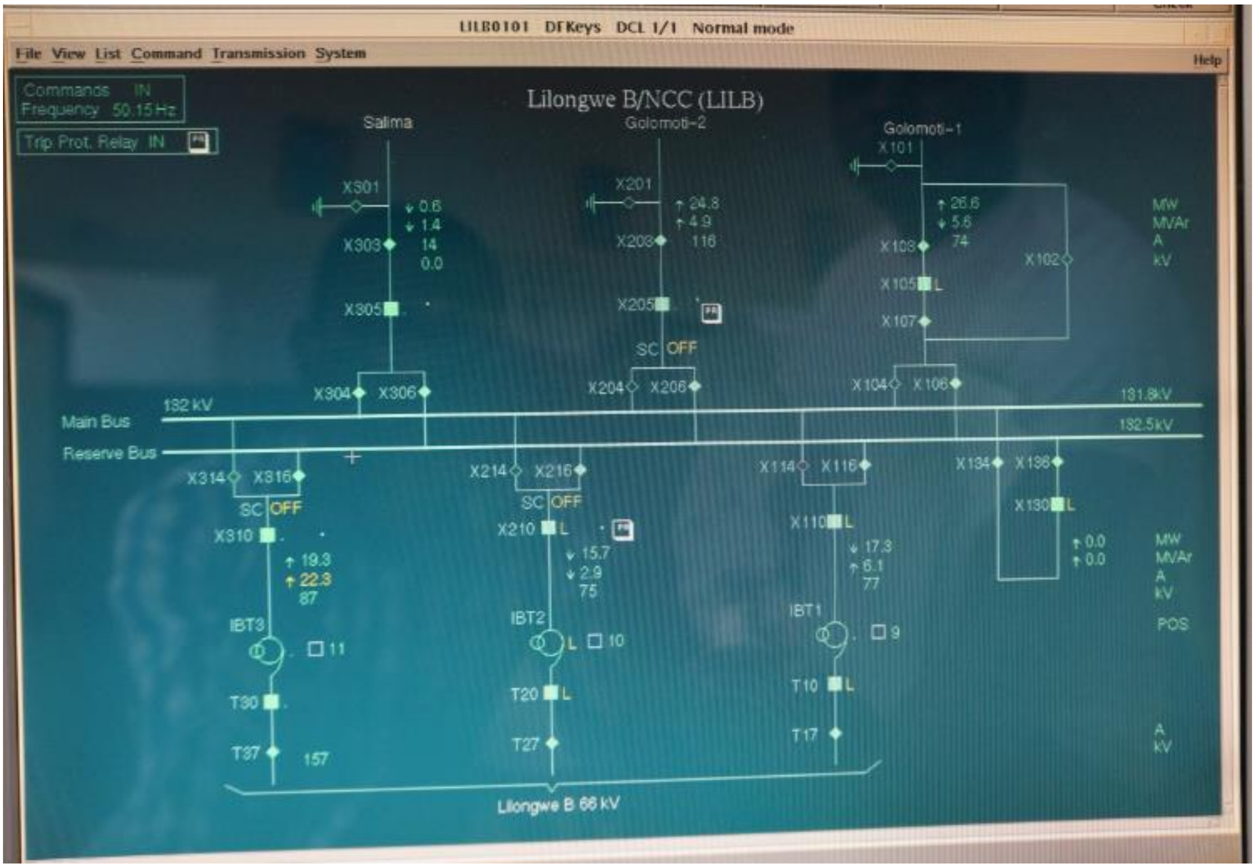
File View List Command Transmission System
Help
Commands IN
Frequency 50.17 Hz
Trip Prot. Relay OUT
Tedzani I & II/NCC (TEDL)
Tedzani III
T3
Nkula B 66 kV
Blantyre 66 kV
Nkula A 66 kV
MW
MVAr
A
kV
BB
66 kV
16.2 kV
78.7 kV
G4
G3
G2
G1


TEDX0101 DFKeys DCL 1/1 Normal mode
File View List Command Transmission System
Help
Commands IN
Frequency 50.24 Hz
Tedzani III/NCC (TEDX)
Water Levels
Kapichira
Nkula B 132 kV
Main Bus
Reserve Bus
132 kV
66 kV
Tedzani I & II
11 kV
Tedzani I & II
G5
G6
T3
MW
MVAr
A
POS


KAPI0101 DFKeys DCL 1/1 Normal mode
File View List Command Transmission System
Check
Help
Commands IN
Frequency 50.24 Hz
132 Kv GIS Switchgear
Control Mode L
Kapichira/NCC (KAPI)
Kapichira Headpond Level 145.7 m
Water Levels
Tedzani III
Blantyre West
Blantyre West
Nchalo
MW
MVAr
A
kV
Main Bus
132 kV
Reserve Bus
Kapichira 33 kV
G1
G2
G3
G4

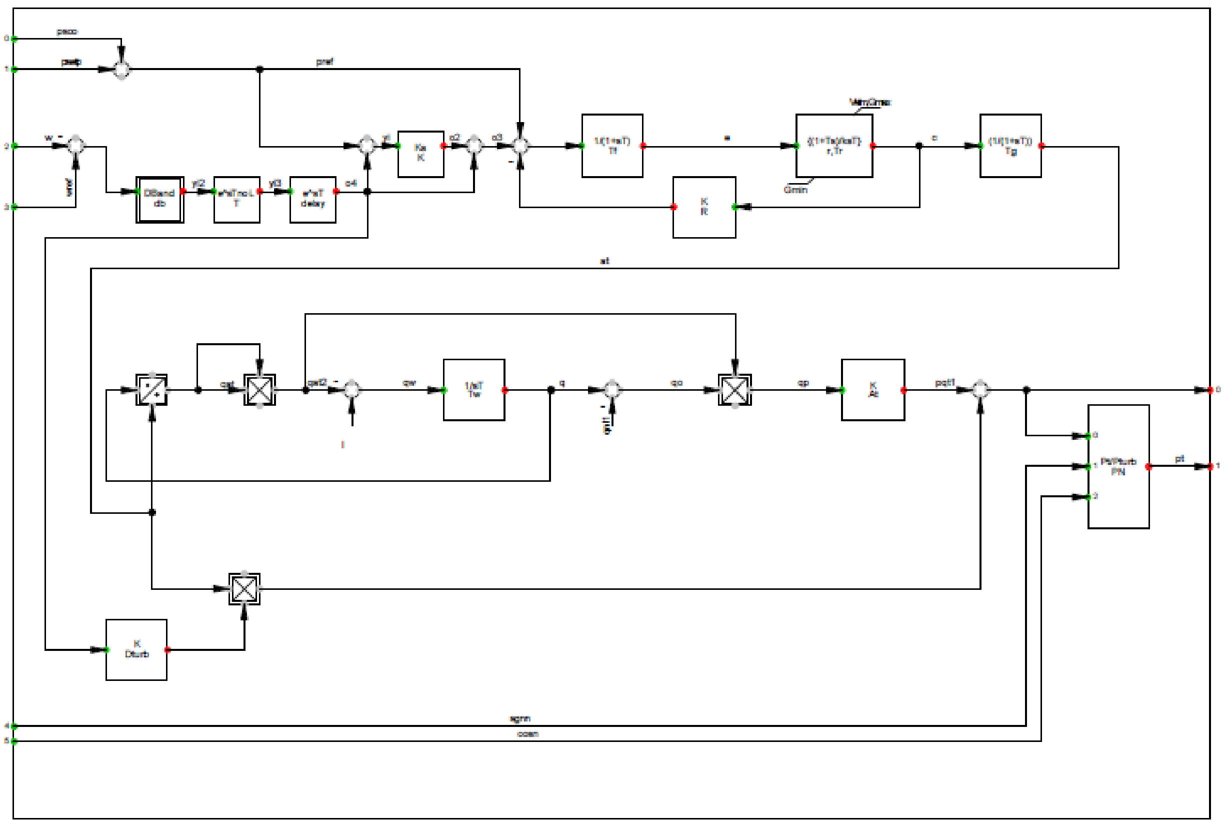

BLWE0101 DFKeys DCL 1/1 Normal mode
File View List Command Transmission System
Status
Check
Help
Commands IN
Frequency 50.17 Hz
Blantyre West/NCC (BLWE)
Kapichira
Nkula B 132 kV
MW
MVAr
A
kV
Main Bus
132 kV
Reserve Bus
Blantyre West 11kV
Blantyre West 66 kV
Blantyre West 66 kV


LILB0101 DFKeys DCL 1/1 Normal mode
File View List Command Transmission System
Help
Commands IN
Frequency 50.15 Hz
Trip Prot. Relay IN
Lilongwe B/NCC (LILB)
Salima
Golomoti-2
Golomoti-1
X301
X303
X305
X304
X306
X201
X203
X205
SC OFF
X204
X206
X101
X103
X105 L
X107
X102
X104
X106
MW
MVAr
A
kV
132 kV
Main Bus
Reserve Bus
131.8kV
132.5kV
X314
X316
X310
X214
X216
X210 L
X114
X116
X110 L
X134
X136
X130 L
IBT3
IBT2
IBT1
T30
T37
T20 L
T27
T10 L
T17
POS
Lilongwe B 66 kV

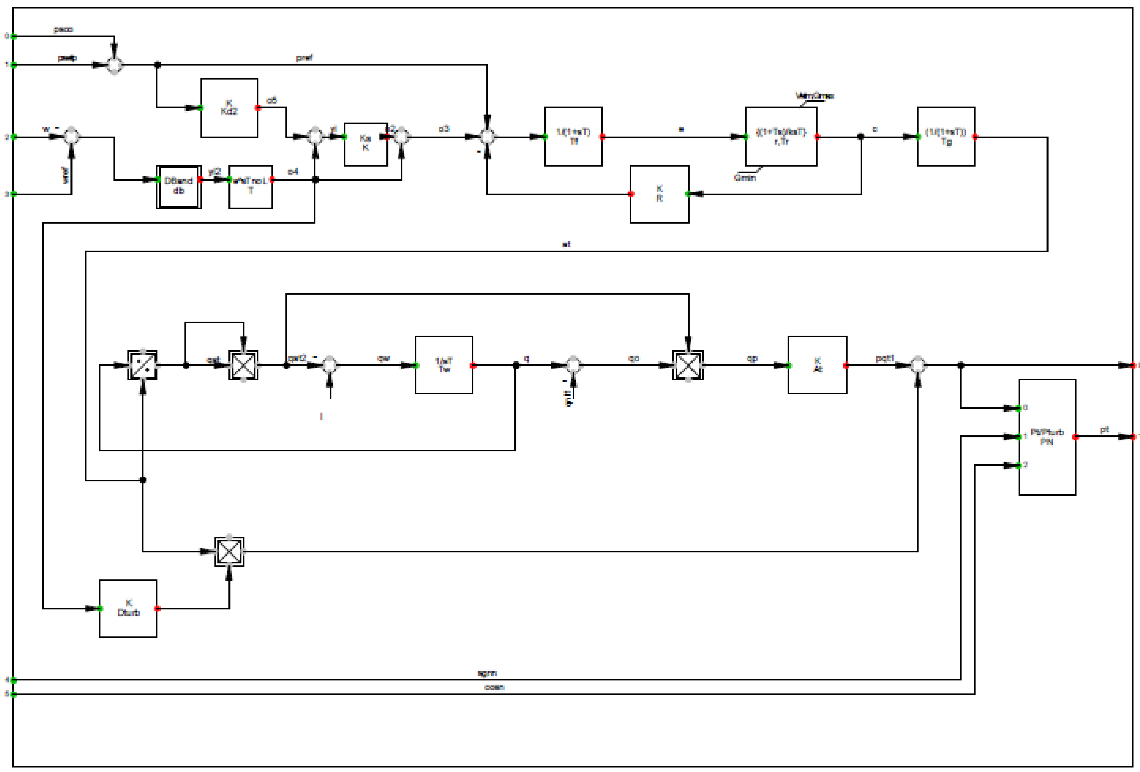
Appendix D – Governor Settings and Control Block Diagrams

Setting	Control Variable	Nkula A	Nkula B	Tedzani 1&2	Tedzani 3	Kapichira 1	Kapichira 2
Temporary Droop (pu)	r	0.7	0.8	0.8	0.4	0.8	0.8
Governor Time Constant (s)	Tr	2	2	2	2	1	1
Filter Time Constant (s)	Tf	0.1	0.1	0.1	0.3	0.1	0.1
Servo Time Constant (s)	Tg	1	0.5	0.5	0.5	0.5	0.5
Water Starting Time (s)	Tw	1.07	0.63	2.46	4.45	2.44	2.44
Turbine Gain (pu)	At	1	1	1	1	1	1
Frictional Losses Factor (pu)	Dturb	0.5	0.5	0.5	0.5	0.5	0.5
No Load Flow (pu)	qnl	0	0	0	0	0	0
Permanent Droop (pu)	R	0.02	0.05	0.04	0.04	0.04	0.04
Frequency Delay (s)	T	0	0	0	5	9	1
Deadband	db	0	0	0	1	0	0.012
Frequency Change Differential	Kd1	0.8	0.1	0.1	0.3	0.1	0
Setpoint Change Differential	Kd2	-	1.1	0.5	0.02	-	-
Minimum Gate Limit (pu)	Gmin	0	0	0	0	0	0
Gate Velocity Limit (pu)	Velm	0.0005	0.01	0.005	0.03	0.004	0.08
Maximum Gate Limit (pu)	Gmax	1	1	1	1	1	1

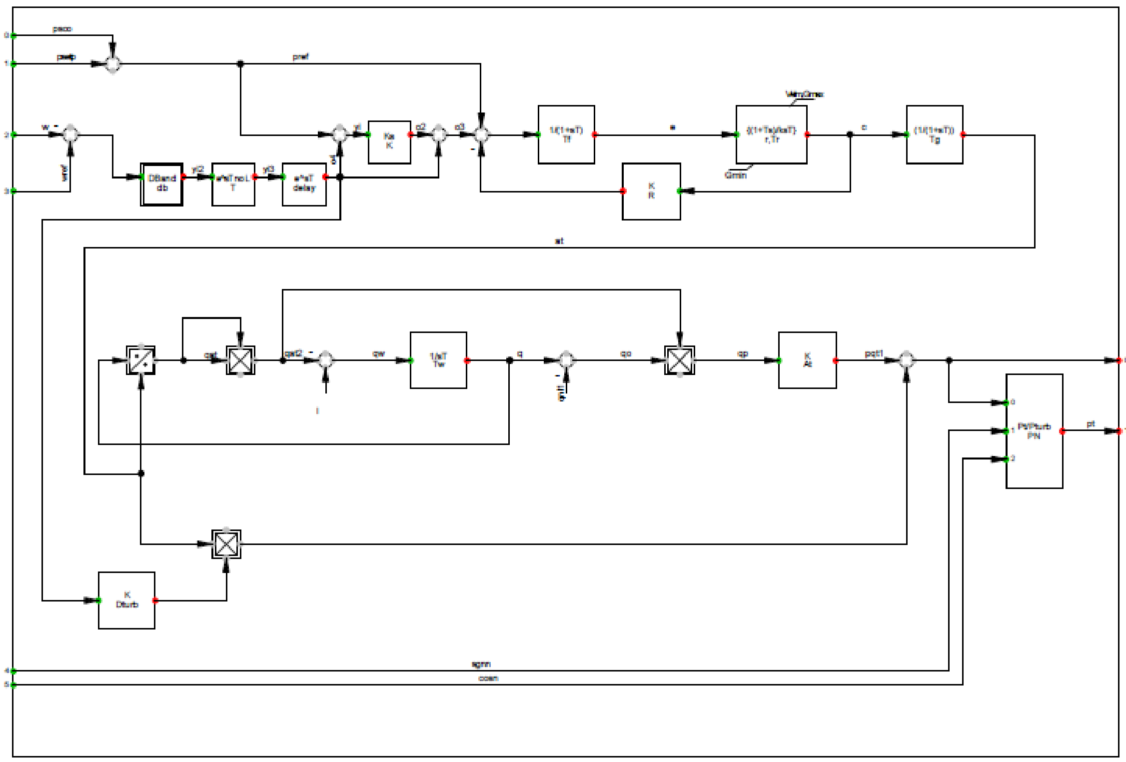
gov_HYGOV_Kap1_run: Hydro Turbine Governor



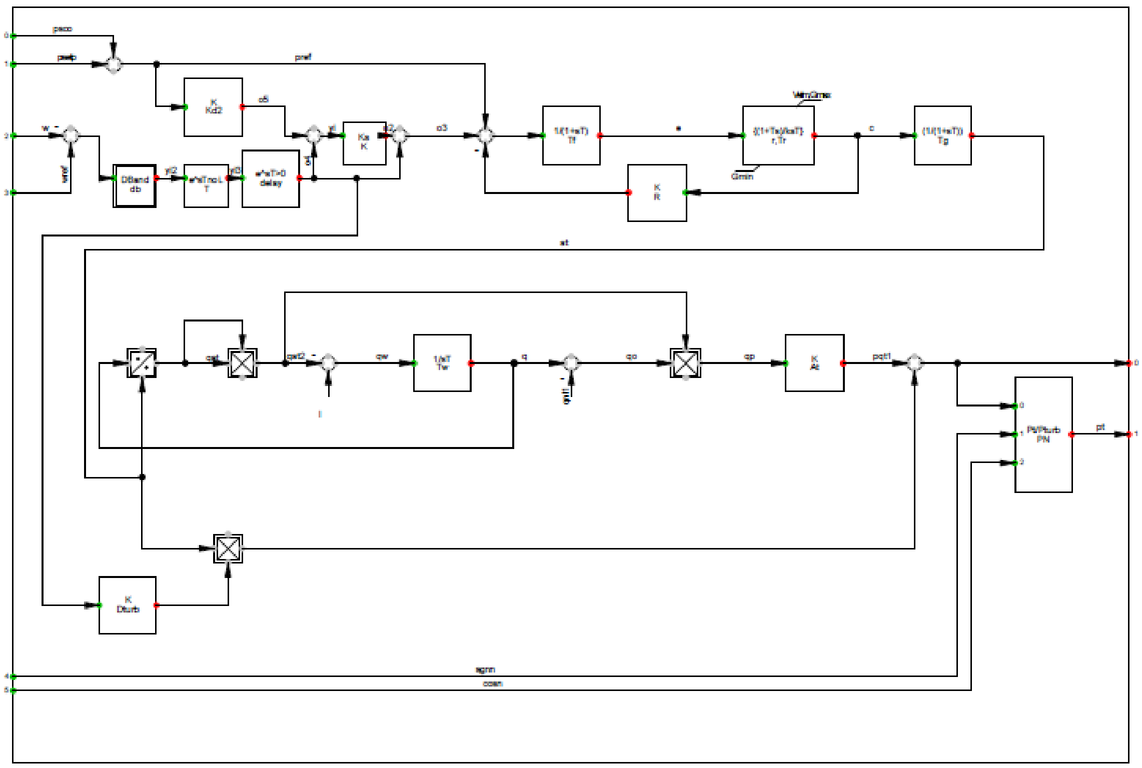
gov_HYGOV_NkulaB_run: Hydro Turbine Governor



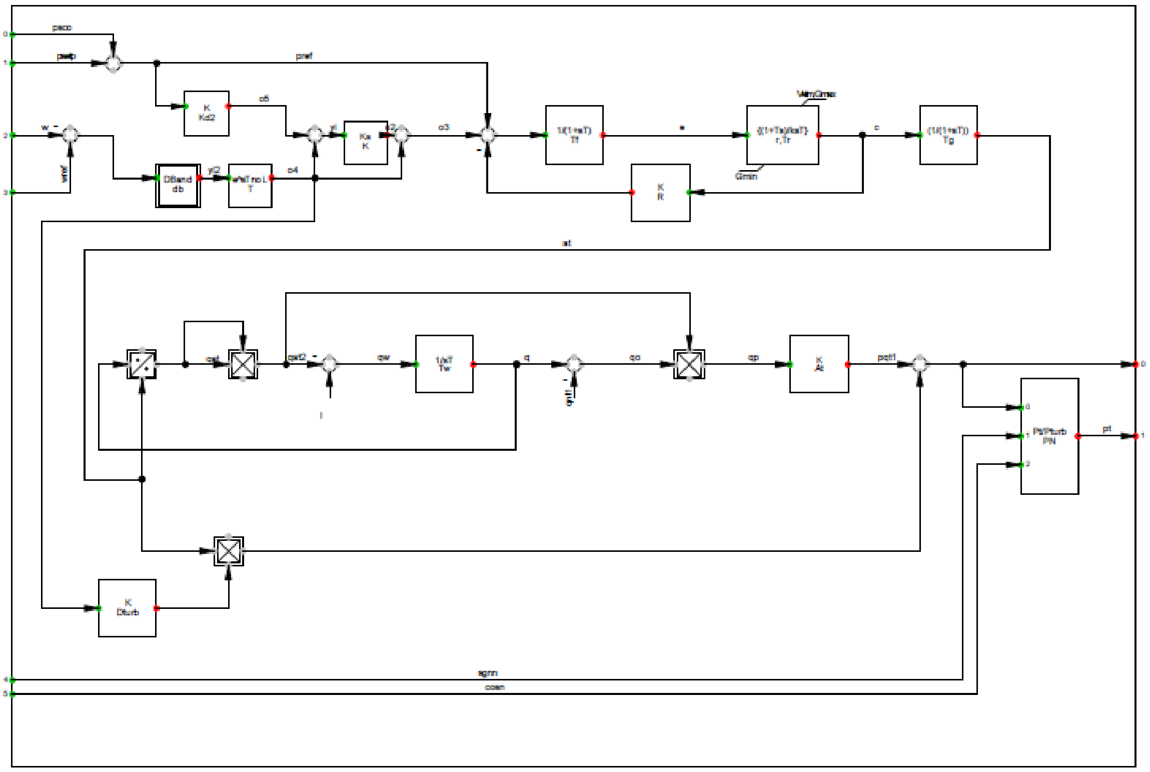
gov_HYGOV_Kap2_run: Hydro Turbine Governor



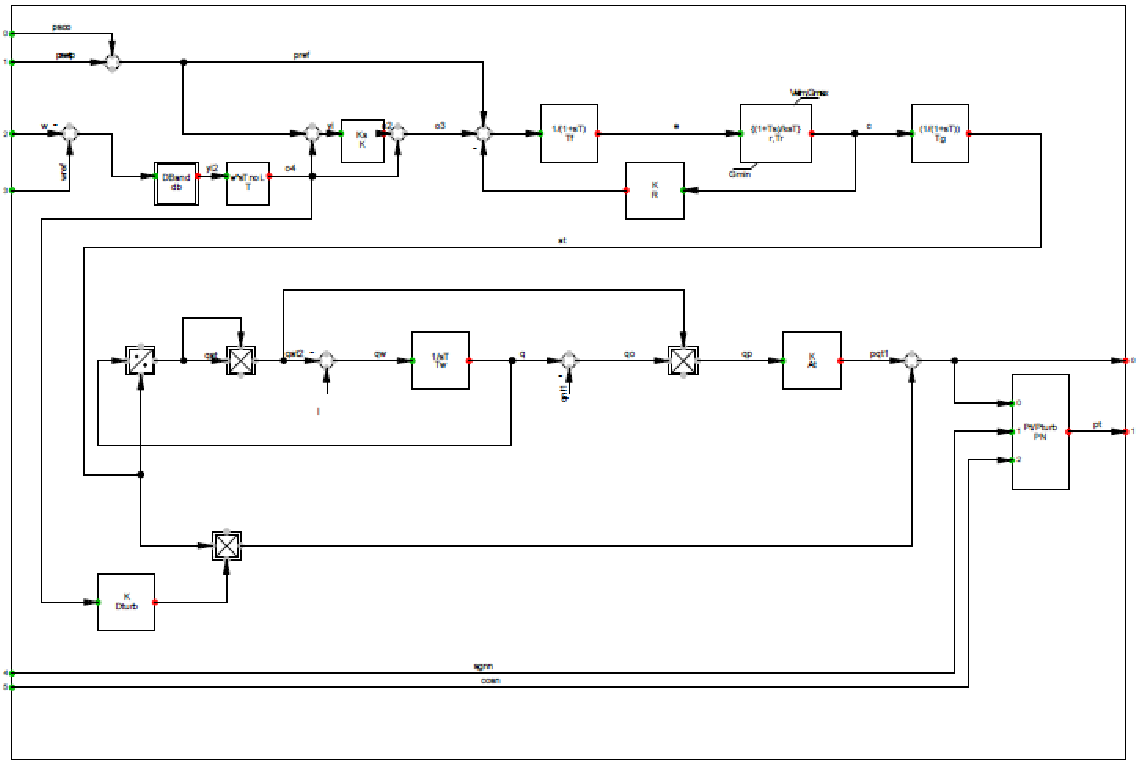
gov_HYGOV_Ted3_run: Hydro Turbine Governor



gov_HYGOV_Ted1&2_run: Hydro Turbine Governor

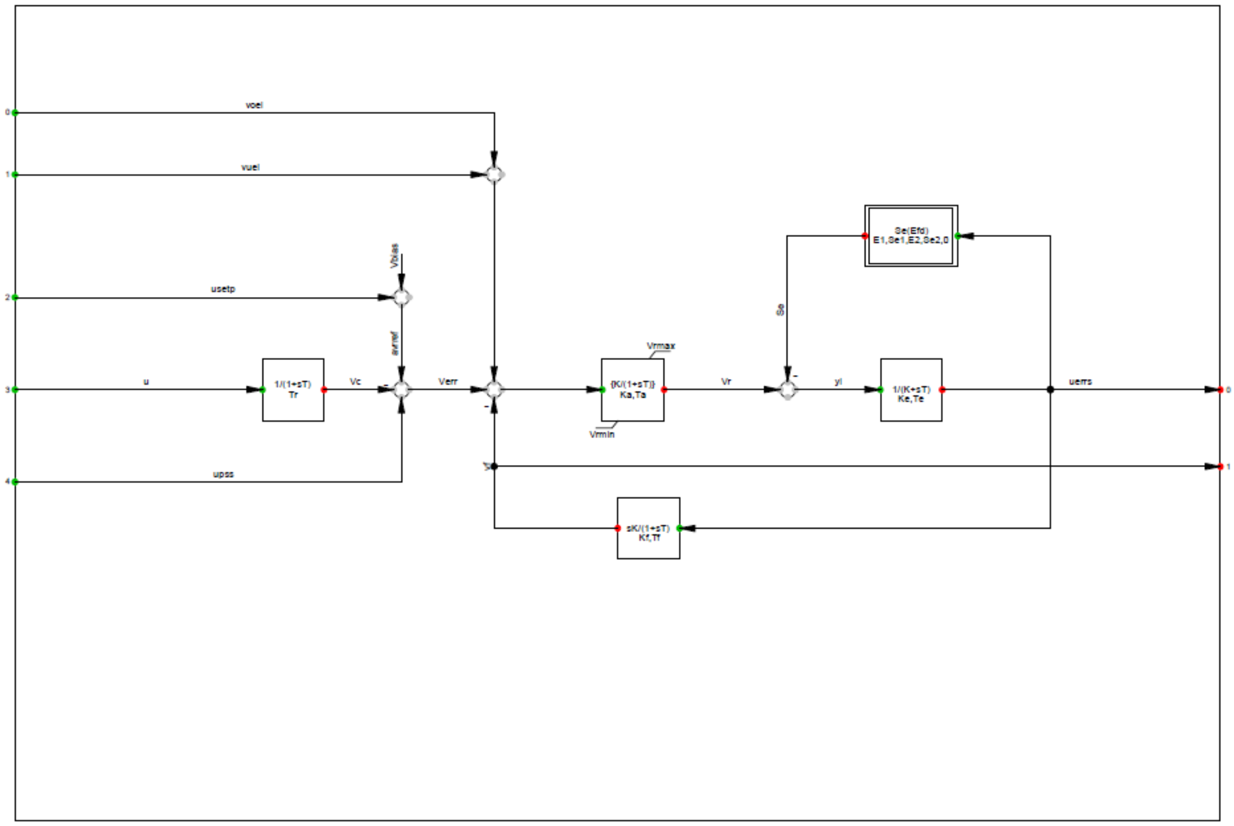


gov_HYGOV_NikulaA_run: Hydro Turbine Governor



Appendix E – IEEE Type 1 Excitation System

avr_IEEET1: 1968 IEEE Type 1 Excitation System



Appendix F – Potential Thermal Power Plants (Malawi Mini IRP 2015)

Project Name	Capacity (MW)	Capacity (GWh)	CAPEX (m$)	Current Project Status	Expected Commissioning year
Kammwamba – Coal	300	1,650	667	Implementation MoU signed between Malawi Government and China-Guezuba	2019–10% 2020–90% 2021–100%
Karonga – Coal	200	1,100	-	FS in progress	2021
Illovo Cogeneration – Bagasse Phase II	40	267	35	FS in progress	2020
Illovo Cogeneration – Bagasse Phase I	11	31.40	6.01	Engineering studies	2017
Chipoka – Coal	-	-	-	Pre – FS in progress	2024
Diesel – Kanengo Phase I	10	17.5	-	Under implementation by ESCOM	2016
Diesel – Mzuzu	6	10.5	-	Procurement of EPC Contractor	2017
Diesel - Kanengo Phase II	10	17.5	-	Awaiting MERA approval in 2017	2018
Diesel – Mapanga	20	35	-	Awaiting MERA approval in 2017	2018

Appendix G – Reserve Margin and Additional Load

Intermittent generation technologies are suitable for providing energy but not base load power or system capacity.

These technologies generally fulfil the role of offsetting the cost of fuel (e.g. coal, HFO or diesel) or filling up hydro generation reservoirs for later use. They are not used as base load because they are not dispatch-able and cannot be relied upon at any one moment in time to output a certain amount of power.

In isolated or islanded power systems such as Malawi without major coal/diesel costs or hydro reservoirs (we do not have an in depth understanding of the Shire river hydrology), intermittent generation offers little to no economic benefits as it is comparatively expensive to run compared to the hydro plants.

The fact that no extra baseload power has been introduced also means that no extra load can be added and this is especially true for Malawi as the current ESCOM power system has relatively small reserve margin which can reach levels of under 10MW during peak loading. At a reduced mid-day loading it is assumed that there is enough reserve to cover the loss of the largest unit on the network (Kapichira 32MW).

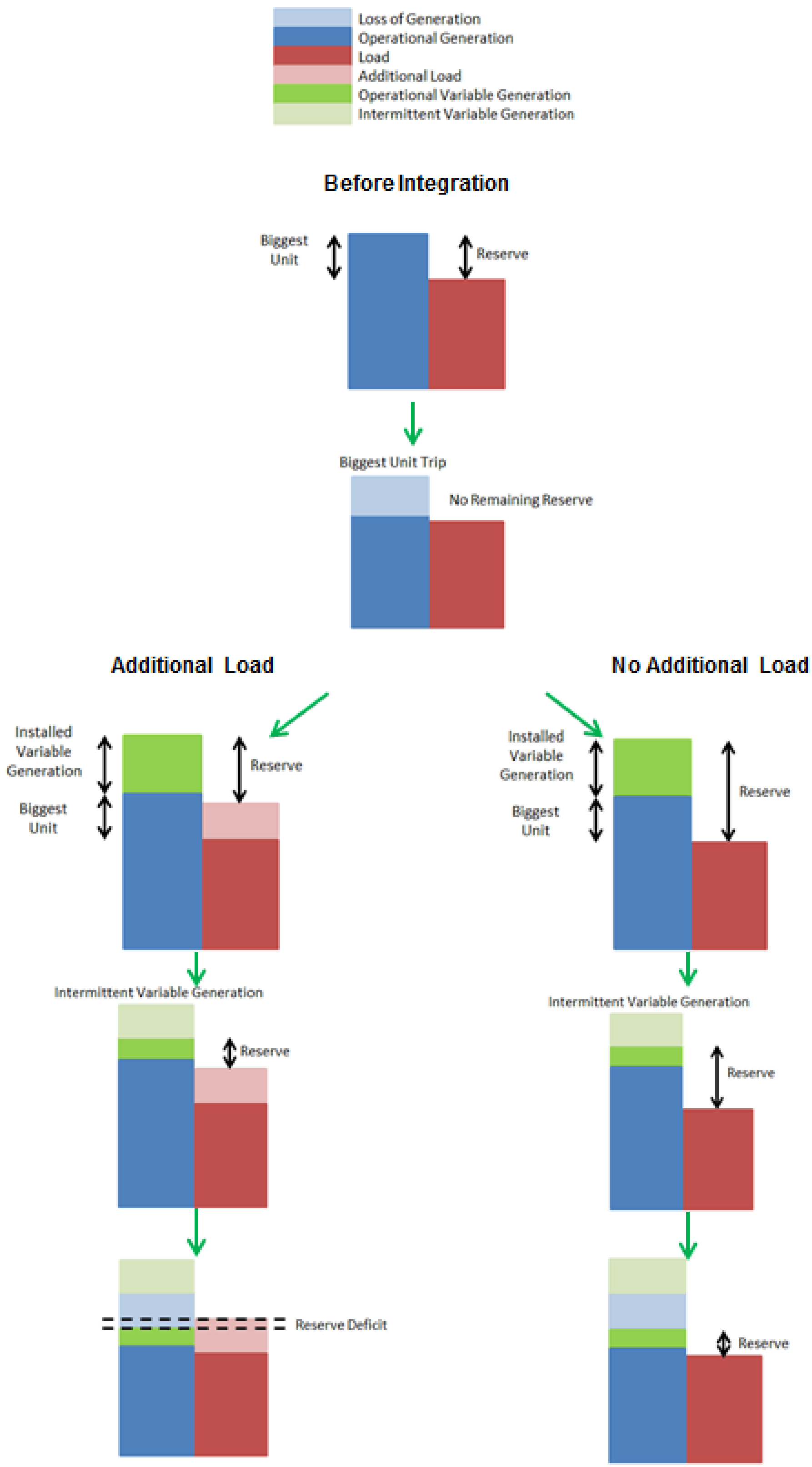
For the purpose of comparison, an extract of the Malawi grid code requirements is presented below.

1) Amount of Reserves required when not connected to the SAPP
    a) The amount of Spinning (Primary) Reserve will be, at least, the power generation needed to maintain the frequency, after the occurrence of the Reference Incident between 49.5 and 50.5 Hz.
    b) The minimum amount of Regulating (Secondary) Reserve shall be:
        i) The amount of power generation needed to continuously balance generation and load, under the control of the AGC, while keeping frequency as close as possible to its nominal value (50 Hz), while the system is in Normal State; or
        ii) The amount of power generation needed to compensate the short term fluctuation of VRE Generation plus the errors in the VRE Generation forecasts; or
        iii) The amount of power generation needed to restore Spinning (Primary) Reserve within 10 minutes after the occurrence of the Reference Incident;

        whichever is larger.
    c) The amount of Regulating (Secondary) plus Quick (Tertiary) reserve will be the power generation needed to recover the frequency to nominal value (50 Hz) in 30 minutes or less, after the occurrence of the Reference Incident.

When comparing the above reserve margin requirements with the actual reserve, it is clear that the system currently only meets the Primary reserve criterion outside of peak loading times and lacks both Secondary and Tertiary reserve at mid-day. The system in effect uses the Primary reserve as Secondary reserve under normal operating conditions.

A simplistic comparison between adding extra load after integration of intermittent generation is presented below. Intermittent generation is not seen as a contingency so the ESCOM power system will still need to ride through a trip of one of the Kapichira units. The risk is that it is possible to end up with a reserve margin that is in effect smaller than the reserve margin was before the variable generation was integrated, making the system more prone to under-frequency load shedding events.


Loss of Generation
Operational Generation
Load
Additional Load
Operational Variable Generation
Intermittent Variable Generation
Before Integration
Biggest Unit
Reserve
Biggest Unit Trip
No Remaining Reserve
Additional Load
No Additional Load
Installed Variable Generation
Biggest Unit
Reserve
Installed Variable Generation
Biggest Unit
Reserve
Intermittent Variable Generation
Reserve
Intermittent Variable Generation
Reserve
Reserve Deficit
Reserve

One option for an economically viable integration of intermittent generation onto the ESCOM grid lies in connecting the isolated power system to SAPP.

Once connected to SAPP, ESCOM will have access to emergency power to satisfy reserve margin requirements. Escom may also be able to import energy (kWh) from the SAPP.

Although it is likely that Malawi will not have coal power or energy storage capabilities in the short term, intermittent energy from RE generation sources will be able to reduce the amount of power being imported over the connector thereby providing some form of economic advantages.

Appendix H – Load Flow Results

Table H.1: 2016 Peak mid-day load Northern 66kV results

Busbar	Voltage	Unity Power Factor MEC (MW)	Loss Reduction (MW)	Limit	Voltage Control MEC (MW)	Loss Reduction (MW)
Area 48	66kV	45	4.53	Thermal	-	-
Barracks	66kV	40	4.15	Voltage	45	4.26
Chinyama	66kV	13	2.41	Voltage	20	1.2
Dedza	66kV	12	3.75	Voltage	50	-6.54
Kanengo	66kV	60	5.68	Voltage	30	3.81
Lilongwe OT1	66kV	37	3.92	Thermal	-	-
Lilongwe OT2	66kV	8.5	3.8	Voltage	50	-14.2
Nkhotakota	66kV	23	4.2	Thermal	-	-
Tsabango	66kV	33	2.92	Thermal	-	-
Bwengu	66kV	4.3	1.88	Thermal	-	-
Chikangawa	66kV	21	4.02	Voltage	45	-1.86
Chintheche	66kV	21	4.74	Voltage	55	1.53
Karonga	66kV	4.3	1.80	Thermal	-	-
Livingstonia	66kV	4.3	1.79	Thermal	-	-
T/Hill	66kV	17	4.48	Voltage	55	-5.96
Uliwa	66kV	4.3	1.76	Thermal	-	-
Balaka	66kV	20	2.92	Voltage	45	-0.14
BT West	66kV	90	-1.79	Thermal	-	-
Changalume	66kV	50	-0.6	Voltage	55	-0.87
Chichiri	66kV	100	0.64	voltage	150	1.73
Chigumula	66kV	95	-0.57	Thermal	-	-
Chingeni	66kV	24	2.6	Voltage	60	-3.37
Fundis Cross	66kV	30	0.33	Voltage	42	-2.09
Golomoti	66kV	30	2.49	Thermal	-	-
Liwonde	66kV	20	2.73	Voltage	45	-1.24
Mapanga	66kV	80	1.07	voltage	125	-0.47
Mlangeni	66kV	15	3.55	Voltage	55	-6.43
Monkey Bay	66kV	22	1.11	Voltage	30	1.23
Ntcheu	66kV	17	3.36	Voltage	55	-4.82
BT West	132kV	100	-1.42	Voltage	130	0.04
Chintheche	132kV	22	4.78	Voltage	95	-2.92
Golomoti	132kV	60	4.03	Voltage	150	3.62
Kanengo	132kV	90	4.66	Voltage	140	4.45
Mlambe	132kV	30	-0.27	Voltage	110	-4.1
Nanjoka	132kV	40	4.39	Voltage	150	0.19
Nkhotakota	132kV	22	4.14	Voltage	105	-3.45

Table H.2: 2018 Peak mid-day load Northern 66kV results

Busbar	Voltage	Unity Power Factor MEC (MW)	Loss Reduction (MW)	Limit	Voltage Control MEC (MW)	Loss Reduction (MW)
Area 48	66kV	50	0.45	Thermal	-	-
Barracks	66kV	65	0.04	Thermal	-	-
Chinyama	66kV	13	0.39	Voltage	20	-1.61
Dedza	66kV	30	0.38	Voltage	70	-6.67
Kanengo	66kV	60	1.19	Voltage	30	-1
Lilongwe OT1	66kV	50	0.06	Thermal	-	-
Lilongwe OT2	66kV	12	0.65	Voltage	50	-8.58
New Lilongwe	66kV	60	0.38	Voltage	125	-2.08
Nkhotakota	66kV	25	1.7	Thermal	-	-
Tsabango	66kV	60	0.08	Voltage	70	-0.95
Bwengu	66kV	20	2.11	Voltage	50	-1.43
Chikangawa	66kV	21	1.69	Voltage	45	-4.87
Chintheche	66kV	20	2.34	Voltage	45	-0.29
Karonga	66kV	12	0.43	Voltage	25	-3.75
Livingstonia	66kV	20	0.79	Voltage	40	-4.94
Thill	66kV	30	1.54	Voltage	35	-0.78
Uliwa	66kV	10	0.6	Voltage	35	-4.78
Balaka	66kV	20	-0.31	Voltage	45	-3.97
BT West	66kV	60	0.14	Thermal	-	-
Changalume	66kV	60	-1.77	Thermal	-	-
Chichiri	66kV	160	0.84	Thermal	-	-
Chigumula	66kV	100	0.49	Thermal	-	-
Chingeni	66kV	22	-0.27	Voltage	75	-10.76
Fundis Cross	66kV	35	-0.61	Voltage	40	-1.8
Golomoti	66kV	100	-1	Voltage	30	-0.47
Liwonde	66kV	20	-0.68	Voltage	40	-5.02
Mapanga	66kV	140	0.99	Thermal	-	-
Mlangeni	66kV	20	-0.1	Voltage	65	-8.09
Monkey Bay	66kV	35	-1.84	Voltage	30	-1.4
Ntcheu	66kV	20	-0.28	Voltage	80	-13.77
BT West	132kV	100	-0.44	Thermal	-	-
Chintheche	132kV	20	2.41	Voltage	100	-20.76
Golomoti	132kV	60	0.45	Voltage	300	-12.96
Kanengo	132kV	80	1.68	Voltage	300	-11.57
Luwinga	132kV	18	2.16	Voltage	95	-19.94
Mlambe	132kV	50	-1.81	Voltage	115	-5.86
Nanjoka	132kV	40	1.08	Voltage	230	-18.97
New Bwengu	132kV	18	2.16	Voltage	95	-19.99
Nkhoma	132kV	80	1.23	Voltage	300	-4.86
Nkhotakota	132kV	22	1.64	Voltage	105	-7.63
Phombeya	132kV	100	0.45	Voltage	300	-2.69

Appendix I – Generation Dispatch

Table I.1: 2016 Midday Peak Generation Dispatch

Generator	Dispatch (MW)
Nkula A G1	8
Nkula A G2	8
Nkula A G3	8
Nkula B G4	17.8
Nkula B G5	17.8
Nkula B G6	17.8
Nkula B G7	17.8
Nkula B G8	-
Tedzani I G1	8.4
Tedzani I G2	8.4
Tedzani II G3	8.4
Tedzani II G4	8.4
Tedzani III G5	27
Tedzani III G6	27
Kapichira I G1	27.2
Kapichira I G2	27.2
Kapichira II G3	27.2
Kapichira II G4	27.2
Wovwe Lumped	4.3

Table I.2: 2018 Midday Peak Generation Dispatch

Generator	Dispatch (MW)
Nkula A G1	8
Nkula A G2	8
Nkula A G3	8
Nkula B G4	18.3
Nkula B G5	18.3
Nkula B G6	18.3
Nkula B G7	18.3
Nkula B G8	18.3
Tedzani I G1	8.6
Tedzani I G2	8.6
Tedzani II G3	8.6
Tedzani II G4	8.6
Tedzani III G5	27
Tedzani III G6	27
Kapichira I G1	28
Kapichira I G2	28
Kapichira II G3	28
Kapichira II G4	28
Wovwe Lumped	4.3