

Dynamic load-shedding analysis for enhancement of power system stability for the Lesotho 132 kV transmission network

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ABSTRACT

In the past two decades, the Lesotho power system load demand increased from below 72 MW to 150 MW. This steep load increase means that the country's power generation of 72MW from hydro-power generators installed at 'Muela is highly lacking and that the country cannot operate without surplus power from the neighbouring states. The South African Eskom tie-line that feeds into Lesotho has thus become crucial for continuous supply of the balance of power and the stable operation of the Lesotho power system, particularly during loading conditions above the installed capacity. Perturbations that affect this tie-line impose stress on the power system and often lead to system collapse. The transient stability of the generating units at 'Muela Hydro-power during and after such network perturbations is key to sustaining continuity of supply to the highest volume of power consumers during the tie-line contingency. It is therefore paramount that inadvertent system collapses be minimised and for the techno-economic status quo to be improved. This study assessed the system loading, using the system data from the Lesotho Electricity Company for the years 2013 and 2017.

Using DIgSILENT for simulations of the performed calculations, the result scans showed the system behaviour during the system disturbances and load changes for the different study cases to support the study outcome. DIgSILENT is a widely used software package in advanced power system calculations and analysis. The core of the proposed solution through the different studies was a successful implementation of dynamic load-shedding for the events that affected the power transfer to the Lesotho power system.

Using the Lesotho and the South African grid code as the basis for the assessment of the system operation limits during emergency operation, this study examined and presented the results showing the impact of tripping different combinations of loads to achieve the supply/demand balance during the faulted system condition. On application of each dynamic load-shedding, the study drew attention to the impact that the dropping of each combination of loads had on the synchronous generators' operational limits, e.g. the active power, reactive power, excitation voltage and the frequency characteristics, which determined whether each case supported safe system operation for adoption by the Lesotho Electricity Company (LEC) and the Lesotho Highlands Development Authority (LHDA). The results showed that through the application of dynamic load-shedding, system collapse caused by disturbances on the tie-line is avoidable. The study's results are valid as post the load-shedding operation, the generating system met the voltage and frequency variations limits in IEEE Std C50.13 – 2014.

The study further tested the system stability during faulted conditions through varying fault clearing times, to determine the critical fault clearing time (CFCT) based on the fault type and

location. The faults on the critical Tweespruit-Mabote transmission lines and on Tweespruit and EMB busbars caused rotor angle swing. Failure to clear these faults within the critical fault clearing times caused the synchronous generators' rotors to swing beyond the stable operating limits (pole-slip/ out-of-step). The results support the suggested time limits for fault clearance to permit continuity of service to more customers.

Based on the results of the successful dynamic load-shedding scheme, this study continued to examine the pre-synchronism loading conditions which permitted successful closing of the tie-line breaker to re-join the two systems by considering the system load prior to closing the tie-line breaker. The pre-synchronising investigation extended to the peak active power oscillations limit to support the limits required to successfully resynchronize the two systems. Finally, the study examined the impact that different load restoration amounts had on the synchronous generators' operation limits, e.g. the active power and frequency oscillations.

The conclusion reached, supported by the results, is that the application of dynamic load-shedding can improve the Lesotho power system stability. The resynchronising of the two systems can succeed if the system satisfied the following requirements prior to reconnection: system loading is less than 112.3% of installed generators' capacity, breaker load angle difference is less than 10.76° , voltage difference is less than 5% and frequency variation is less than 0.6 Hz.

Key words – power system stability, dynamic load-shedding, critical fault clearing time, transmission line

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OPSOMMING

In afgelope twee dekades het die Lesotho-kragstelsel se lasaanvraag van onder 72 MW tot 150 MW toegeneem. Hierdie skerp lastoename beteken dat die land se kragopwekking van 72 MW van geïnstalleerde hidro-kragopwekkers by 'Muela hoogs-ontoereikend is en die land kan nie suksesvol elektrisiteit voorsien sonder aanvullende krag van aangrensende lande nie. Die Suid-Afrikaanse Eskom koppellyn wat krag aan Lesotho voorsien het dus krities geraak vir kontinue voorsiening van addisionele krag en die stabiele bedryf van die Lesotho-kragstelsel, veral gedurende lastoestande bo die geïnstalleerde eie kapasiteit. Steurnisse wat hierdie koppellyn affekteer plaas stres op die kragstelsel wat dikwels tot die faling van die stelsel lei. Die oorgangstabiliteit van die opwekkers by 'Muela-hidrokragsstasie gedurende en na sulke netwerksteurnisse is die sleutel tot volhoubare kontinuïteit van voorsiening aan die grootste getal elektrisiteitsverbruikers gedurende die koppellyngebeurlikheid. Daarom is dit van kardinale belang dat onopsetlike stelselafalings geminimaliseer word en om die tegno-ekonomiese status quo te verbeter. Hierdie studie het stelselbelading geassesseer deur die stelseldata van die Lesotho Electricity Company vir die jare 2013 en 2017 te gebruik.

Deur DIgSILENT vir simulاسies van die uitgevoerde berekeninge te gebruik, het die resultaatkanderings die stelselgedrag gedurende die stelselstoornisse en lasveranderinge vir die verskillende studiegevalle gewys om die studie-uitkomst te ondersteun. DIgSILENT is 'n sagtewarepakket wat baie gebruik word in gevorderde kragstelselberekeninge en analise. Die kern van die voorgestelde oplossing deur verskillende studies was 'n suksesvolle implementering van dinamiese beurtkrag vir die gebeure wat die energietoedrag na die Lesotho-kragstelsel affekteer.

Deur die netwerkkode van Lesotho en Suid-Afrika as die basis vir die assessering van die stelselbedryfslimiete gedurende noodbedryf te gebruik, het hierdie studie die resultate ondersoek en aangebied deur die impak van die klink van verskillende kombinasies van laste te wys om die aanbod-/aanvraagbalans gedurende die foutiewe stelseltoestand te verkry. Met die toepassing van elke dinamiese beurtkrag, het die studie die aandag gevestig op die impak wat die verlaging van elke kombinasie van laste op die sinchrone generator se bedryfslimiete het, bv. die aktiewe drywing, reaktiewe drywing, veldspanning en die frekwensiekarakteristieke, wat bepaal het of elke geval veilige stelselbedryf ondersteun vir aanneming deur die Lesotho Electricity Company (LEC) en die Lesotho Highlands Development Authority (LHDA). Die resultate het getoon dat die toepassing van dinamiese beurtkrag stelselafalings wat veroorsaak word deur stoornisse op die koppellyn kan verhoed. Die studie se resultate is geldig na die toepassing van beurtkrag. Die opwekkingstelsel het voldoen aan die spannings- en frekwensie-variabelielimiete in IEEE Std C50.13 van 2014.

Die studie het ook stelselstabiliteit getoets gedurende fouttoestande deur foutwegruimingstye te varieer om die kritiese foutwegruimingstyd te bepaal gebaseer op die fouttipe en -ligging. Die foute op die kritiese Tweespruit-Mabote transmissielyne en op Tweespruit en EMB geleistamme veroorsaak rotorswaaihoek. Versuim om hierdie foute uit die weg te ruim binne die kritiese foutwegruimingstye het veroorsaak dat die sinchrone generators se rotors om oor die stabiele bedryfslimiete (poolglip/uitpas) te swaai. Die resultate ondersteun die voorgestelde tydlimiete vir foutwegruiming om die kontinuïteit van diens vir meer verbruikers toe te laat.

Gebaseer op die resultate van die suksesvolle dinamiese beurtkragskema, het hierdie studie voorts die voorsinchronisasielasmaatstawes beoordeel wat suksesvolle sluiting van die koppellynbreker om die twee stelsels weer te koppel deur die stelsellaaie voor sluiting van die koppelbreker in ag te neem. Die voorsinchronisasieondersoek het die maksimum aktiewe drywingsosillasielimiet bepaal wat vereis word om die twee stelsels suksesvol te hersinchroniseer. In die laaste plek het die studie die impak wat verskillende lasherstelhoeveelhede op die sinchroongenerators se bedryfslimiete gehad het, bv. die aktiewe drywings- en frekwensieosillasies, ondersoek.

Die slotsom, wat deur die resultate ondersteun word, is dat die toepassing van dinamiese beurtkrag die Lesotho-kragstelselstabiliteit kan verbeter. Die hersinchronisering van die twee stelsels kan suksesvol wees indien die stelsel die volgende vereistes voor herkonneksie bevredig: stelselbelasting is minder as 112.3% van die generators se vermoë, brekerlashoek verskil is minder as 10.76° , spanningsverskil is minder as 5% en frekwensievariasie is minder as 0.6 Hz.

Sleutelwoorde – kragstelselstabiliteit, dinamiese beurtkrag, kritiese foutwegruimingstyd, transmissielyn

DECLARATION OF ORIGINALITY

I, Ikaneng Victor Raphoolo declare herewith that the dissertation / article entitled “Dynamic load-shedding analysis for enhancement of power system stability for Lesotho 132 kV transmission network”, which I herewith submit to the North-West University in compliance with the requirements set for the degree: *Master of Science in Electrical and Electronic Engineering* is my own work, has been text-edited in accordance with the requirements and has not already been submitted to any other university.



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Signed on this 20th day of *November* of 2018

TABLE OF CONTENTS

ACKNOWLEDGEMENTS	I
ABSTRACT ..	II
DECLARATION OF ORIGINALITY	VI
1.1 Background	1
1.2 Problem statement	2
1.2.1 Sub-problems	2
1.3 Objectives	3
1.4 Benefits of study	3
1.5 Delimitation of study	4
1.6 Method of investigation	4
1.7 Structure of the report.....	5
2.1 Power and frequency relationship	9
2.1.1 Local oscillations	10
2.1.2 Interplant oscillations	11
2.1.3 Interarea oscillations.....	11
2.1.4 Global oscillations.....	11
2.2 Synchronous generators	11
2.3 Generator excitation system.....	17
2.3.1 Limiting factors in the operation of an excitation system	17
2.3.2 Output signals from an excitation system.....	18
2.3.3 Excitation system functional block diagram.....	18

2.3.4	Excitation systems technologies	19
2.3.5	Power system stabilisers	21
2.3.6	Generator output voltage	22
2.4	Load-flow study	24
2.4.1	Load buses (PQ nodes).....	26
2.4.2	Voltage controlled buses (PV nodes).....	26
2.4.3	Slack buses	26
2.5	System losses.....	27
2.5.1	No-load losses	27
2.5.2	Load losses	28
2.5.3	Regulation losses	28
2.6	Active power and frequency control / Load frequency control	28
2.6.1	Primary frequency control.....	30
2.6.2	Secondary control.....	31
2.6.3	Tertiary control.....	32
2.6.4	Time control.....	32
2.7	Reactive power and voltage control.....	32
2.7.1	Q-V characteristics of the power system.....	33
2.7.2	Reactive power control	35
2.7.3	Voltage control.....	36
2.7.4	Voltage stability	39
2.7.5	Prevention of voltage collapse	45
2.8	Underfrequency load-shedding	45

2.8.1	Static load-shedding	47
2.8.2	Rate-of-change of frequency load-shedding	48
2.8.3	Dynamic load-shedding	49
2.8.4	Adaptive load-shedding	50
2.9	Recent events of blackouts around the globe.....	52
2.9.1	Turkey 2015 Blackout	53
2.9.2	India 2012 Blackout	54
2.9.3	The 2003 Northeast blackout in the USA	55
2.9.4	Summary of causes of blackouts on selected global events	56
2.9.5	The evolution of load-shedding in the Southern African Power Pool (SAPP)	56
2.10	History of load-shedding and blackouts in Lesotho	56
2.10.1	Lesotho Semi-blackout on 8 th May 2016	57
2.10.2	Lesotho blackout on 16 th March 2018 (06:00 to 09:00)	58
2.11	Summary	58
3.1	System overview	61
3.2	Overview of the system modelling approach	61
3.3	System configuration of the 132 kV system	61
3.4	Evaluation of system loading for a year	64
3.5	Voltage and frequency dependency of loads	69
3.6	System modelling.....	69
3.6.1	Modelling of generators	71
3.6.2	Generator losses	72
3.6.3	Generator controls.....	72

3.6.4	Modelling of transformers	75
3.6.5	Modelling of overhead lines	77
3.6.6	Modelling of the loads	82
3.6.7	Load-flow solution	84
3.6.8	Excluded mini-hydro power stations	85
3.7	Synchronous generator model	86
3.7.1	Impact of dynamic conditions on generator speed	86
3.7.2	Relationship between sending and receiving end power	86
3.8	System reactive power support	87
3.9	Modelling underfrequency load-shedding	87
3.9.1	Triggers for load-shedding	87
3.9.2	Installation and location of underfrequency relays	87
3.9.3	Design of load-shedding stages	88
3.10	Existing frequency and voltage relay scheme at Mabote 132 kV	88
3.10.1	Comments on the settings	89
3.11	Existing frequency and voltage relay scheme at 'Muela generation station	89
3.11.1	Comments on the settings	90
3.12	Testing of the allowable stability limit values	91
3.12.1	Simulation of system response on a three-phase fault at Tweespruit busbars	91
3.12.2	Simulating for duplicating 8 th May 2016 event	96
3.13	Summary	99
4.1	Examination of the power system stability model	103

4.1.1	Active power and reactive power	103
4.1.2	Excitation voltage	104
4.1.3	Rotor angle of the generators and torque	104
4.1.4	Generator speed and frequency	104
4.1.5	Line-to-line voltage	104
4.1.6	Generator currents and transmission line phase currents	104
4.2	System load analysis	105
4.3	Initial operating point	105
4.4	Options for tripping different loads during a tie-line loss contingency....	105
4.4.1	Results of study cases 1 to 5.....	109
4.4.2	Results of study cases 6 to 8.....	111
4.5	Transient stability assessment for faults upstream to EMB substation...	114
4.5.1	Three-phase fault at Tweespruit substation – with automatic load-shedding...	116
4.5.2	Line faults on Tweespruit-Mabote and Mabote-Maputsoe transmission lines..	120
4.5.3	System faults at the Mabote 33 kV busbars	128
4.6	Impact of loss of one generator during island operation	130
4.7	Evaluation of SVC impact during the tie-line loss contingency	131
4.8	Evaluation of system behaviour during resynchronisation	133
4.8.1	The impact of the system load on frequency.....	135
4.8.2	The impact of the system load on voltage difference between the two systems	135
4.8.3	The impact of the system load on the load angle between the two systems ...	136
4.8.4	The impact of system load on peak active power swing.....	136
4.9	Power restoration	137

4.10	Summary	140
5.1	Introduction	142
5.2	Findings	142
5.2.1	System capacity and constraints.....	142
5.2.2	Past system collapse events.....	142
5.2.3	Load-shedding.....	143
5.2.4	Transient stability analysis.....	143
5.2.5	The SVC installation to improve voltage stability.....	143
5.2.6	Generator event during islanding	143
5.2.7	Conditions for synchronism.....	143
5.2.8	Power restoration procedure.....	144
5.3	Recommendations.....	144
5.4	Conclusions.....	144
APPENDICES.....		153
Appendix A- SAUPEC 2019 publication.....		154
ANNEXURES		163
Annexure 1: The Lesotho power system single line diagram (embedded in word file and in separate pdf file)		163
Annexure 2: The automatic voltage regulator (AVR) space model for IEEE T1		165
Annexure 3: The combination of loads dropped for load-shedding in study case 1 to 8		167
Annexure 4: The additional simulation scans for transient stability on the Tweespruit-EMB and Mabote-Maputsoe transmission lines		170
Annexure 5: The simulation results for the requisition of synchronism in the grid.....		179

LIST OF TABLES

TABLE 1-1 – A LIST OF RECENT BLACKOUTS IN LESOTHO.....	2
TABLE 2-1: SUMMARY OF FUNCTIONS OF ELEMENTS THAT MAKE UP THE EXCITATION SYSTEM.....	19
TABLE 3-1: SCHEDULE OF LOADING ON THE 132 kV TRANSMISSION SYSTEM.....	64
TABLE 3-2: GRID PARAMETERS FOR RMS-SIMULATION.....	70
TABLE 3-3: RESISTANCES, REACTANCE, AND TIME CONSTANT FOR 32 MVA GENERATORS [41]	71
TABLE 3-4: POWER GENERATOR(S) LOSSES [41].....	72
TABLE 3-5: GOVERNOR GOV_HYGOV PARAMETERS [12]	73
TABLE 3-6: AVR SYSTEM PARAMETER USED FOR MODELLING THE SYSTEM RESPONSE [12]	73
TABLE 3-7: POWER SYSTEM STABILIZER MODEL PSS2A SETTINGS	74
TABLE 3-8: SCHEDULE OF LOADING ON TWO-WINDING 132 / 33 kV TRANSFORMERS.....	77
TABLE 3-9: SCHEDULE OF LOADING ON THREE-WINDING 132 /66/ 11 kV TRANSFORMERS.....	77
TABLE 3-10: STANDARD DIGSILENT OVERHEAD LINE PARAMETERS FOR SYSTEM MODELLING	79
TABLE 3-11: THE COORDINATES OF DOUBLE CIRCUIT, 132 kV LINE STRUCTURES	80
TABLE 3-12: THE COORDINATES OF SINGLE CIRCUIT, 132 kV LINE STRUCTURES.....	80
TABLE 3-13: THE COORDINATES OF SINGLE CIRCUIT, 132 kV LINE STRUCTURES.....	81
TABLE 3-14: SELECTION OF THE <i>K_{pf}/K_{qf}</i> VALUE FOR DIFFERENT LOAD MODEL BEHAVIOURS IN DIGSILENT [12]	84
TABLE 3-15: LEC POWER CAPACITY SUMMARY.....	85
TABLE 3-16: SUMMARY OF EXCLUDED MINI-HYDRO GENERATION STATIONS IN THE MODEL	85
TABLE 3-17: EXISTING FREQUENCY RELAY SETTINGS.....	89
TABLE 3-18: EXISTING VOLTAGE RELAY SETTINGS (SECONDARY LINE-TO-LINE VALUES).....	89
TABLE 3-19: SCHEDULE OF FREQUENCY RELAY SETTINGS	90
TABLE 3-20: SCHEDULE OF VOLTAGE PROTECTION RELAY SETTINGS CONNECTED TO THE SECONDARY VT TERMINALS	90
TABLE 4-1: SCHEDULE OF DIFFERENT SCHEMES FOR TRIPPING LOADS USING 150 MW AS THE BASE LOAD	102
TABLE 4-2: ESTIMATION OF SUPPLIED OPTIMAL LOAD DURING A TIE-LINE LOSS	106
TABLE 4-3: ESTIMATION OF TOTAL LOAD-SHED, INCLUDING THE SYSTEM LOSSES	106
TABLE 4-4: CASE STUDY 1 - 8 FOR LOAD-SHEDDING SCHEME OPTIONS	107
TABLE 4-5:THE PROTECTION SCHEME FOR LOAD-SHEDDING STUDY CASE 8 DURING A THREE-PHASE FAULT AT TWEESPRUIT.	117
TABLE 4-6: CRITICAL CONTINGENCIES AND IMPACT ON MABOTE 132 kV SUBSTATION	129
TABLE 4-7: SUMMARY OF SYSTEM RESULTS WHEN SUBJECTED TO DIFFERENT LOADING CONDITIONS	134
TABLE 4-8: SCHEDULE FOR RESTORING LOADS SHED.....	138

LIST OF FIGURES

FIGURE 1-1: SUMMARY OF THE STUDY PROCESS FLOW	5
FIGURE 2-1: FREQUENCY VERSUS POWER RESPONSE CHARACTERISTICS UNDER LOAD MISMATCH CONDITIONS [1]	10
FIGURE 2-2: D-Q AXIS PRESENTATION OF THREE-PHASE SYNCHRONOUS MACHINES [5]	12
FIGURE 2-3: THE EQUIVALENT CIRCUIT SHOWING THE WINDINGS PER UNIT LEAKAGE INDUCTANCES [7]	13
FIGURE 2-4: THE WINDINGS OF SYNCHRONOUS GENERATOR AND THEIR AXES [11]	14
FIGURE 2-5: CHARACTERISTIC OF FREQUENCY DEVIATION FOLLOWING ACTIVE POWER UNBALANCE [12].....	17
FIGURE 2-6: FUNCTIONAL BLOCK DIAGRAM OF EXCITATION SYSTEM [15].....	19
FIGURE 2-7: GENERAL FUNCTIONAL BLOCK DIAGRAM OF DC EXCITER MODEL [17].....	20
FIGURE 2-8: TYPICAL FUNCTIONAL BLOCK DIAGRAM OF AC EXCITER MODEL [11]	21
FIGURE 2-9: TYPICAL FUNCTIONAL BLOCK DIAGRAM FOR STATIC EXCITATION SYSTEM [17]	21
FIGURE 2-10: SPACE PRESENTATION OF PSS RELATIONSHIP WITH OTHER SYSTEM FUNCTIONAL ELEMENTS [10]	22
FIGURE 2-11: PHASOR DIAGRAM OF SYNCHRONOUS MACHINE UNDER BALANCED STEADY STATE CONDITION [4]..	23
FIGURE 2-12: REPRESENTATION OF POWER SYSTEM COMPONENTS REQUIRED FOR LOAD FLOW [11]	25
FIGURE 2-13: SOURCES OF ENERGY LOSSES IN POWER SYSTEM [20]	27
FIGURE 2-14: SCHEMATIC DIAGRAM OF A MECHANICAL HYDRAULIC GOVERNOR FOR HYDRO TURBINES [1]	29
FIGURE 2-15: ILLUSTRATION OF V-P RELATIONSHIP FOR A SELECTED BUS IN A SYSTEM [1]	33
FIGURE 2-16: ILLUSTRATION OF Q-V CHARACTERISTICS IN RELATION TO VOLTAGE STABILITY [1]	34
FIGURE 2-17: ILLUSTRATION OF Q-V CURVES AT CRITICAL OPERATING CONDITIONS [1].....	35
FIGURE 2-18: ILLUSTRATION OF LINE AND TRANSFORMER CONNECTED REACTORS [1]	37
FIGURE 2-19: AN ILLUSTRATION OF IDEALISED STATIC VAR COMPENSATOR CONNECTION [25]	37
FIGURE 2-20: TYPICAL STATCOM BASED ON VOLTAGE CONVERTER AND ITS CHARACTERISTICS FOR CURRENT VS VOLTAGE AND POWER VS VOLTAGE [10].....	38
FIGURE 2-21: ILLUSTRATION OF STEP VOLTAGE REGULATOR [1].....	39
FIGURE 2-22: A TYPICAL TWO-PORT SYSTEM TO EXEMPLIFY VOLTAGE STABILITY OCCURRENCE [1]	41
FIGURE 2-23: RELATIONSHIP BETWEEN RECEIVING END VOLTAGE, CURRENT AND POWER [1].....	42
FIGURE 2-24: SYSTEM BEHAVIOUR UNDER DIFFERENT LOAD-POWER FACTOR [1]	43
FIGURE 2-25: AN ILLUSTRATION OF VOLTAGE COLLAPSE [10]	43
FIGURE 2-26: FLOW CHART SHOWING THE PROCEDURE IN POWER SYSTEM STABILITY STUDIES INCLUDING LOAD- SHEDDING [13]	46
FIGURE 2-27: ILLUSTRATION OF THE FOUR STEPS OPERATION IN DYNAMIC LOAD-SHEDDING TECHNIQUE	50
FIGURE 2-28: INCIDENTS OF BLACKOUTS AROUND THE GLOBE, CIRCULAR REPRESENTATION DEPICTS SEVERITY OF THE INCIDENT [31].....	53

FIGURE 2-29: THE ANGULAR DIFFERENCE BETWEEN THE NORTHERN AND WESTERN REGIONS (A), THE FREQUENCY OF NORTHERN REGION (B), AND WESTERN REGION FREQUENCY (C) WHEN SUBJECTED TO AN 3.5% INCREASE IN REAL AND REACTIVE POWER IN THE NORTHERN REGION	55
FIGURE 2-30: SCHEMATIC DIAGRAM SHOWING THE TIE-LINES CONNECTION BETWEEN ESKOM AND LEC NETWORK	57
FIGURE 3-1: OVERVIEW OF THE LESOTHO 132 kV POWER SYSTEM LAYOUT	63
FIGURE 3-2: SUMMARY OF ACTIVE POWER IN MW AND APPARENT POWER IN MVA FOR THE YEAR 2013	66
FIGURE 3-3: SUMMARY OF REACTIVE IN MVAR FOR THE YEAR 2013.....	66
FIGURE 3-4: THE ACTIVE AND APPARENT POWER CONSUMPTION TREND FOR JULY 2013.....	67
FIGURE 3-5: THE REACTIVE POWER CONSUMPTION TREND FOR JULY 2013	67
FIGURE 3-6: SUMMARY OF THE ACTIVE IN MW AND APPARENT IN MVA POWER LOADING FOR THE YEAR 2017	68
FIGURE 3-7: SUMMARY OF REACTIVE IN MVAR POWER LOADING FOR THE YEAR 2017.....	68
FIGURE 3-8: ILLUSTRATION OF EQUIVALENT CIRCUIT IN REFERENCE TO THE PRIMARY [21].....	75
FIGURE 3-9: ILLUSTRATION OF AN ON-LOAD TAP CHANGER USING BOTH A REACTOR (A) AND RESISTOR (B)	76
FIGURE 3-10: EQUIVALENT PI-CIRCUIT PRESENTATION OF LUMPED PARAMETERS [12].....	78
FIGURE 3-11: THREE-PHASE LINE WITH IDENTICAL SPACING BETWEEN ALL PHASES [44].....	82
FIGURE 3-12: IEC 60034-3 GENERATOR OPERATION BOUNDARIES FOR FREQUENCY AND VOLTAGE [49]	88
FIGURE 3-13: VOLTAGE MAGNITUDE IN P.U. FOLLOWING A THREE-PHASE FAULT AT EMB BUSBARS FOR BOTH FAULT CASES	92
FIGURE 3-14: ELECTRICAL FREQUENCY IN HZ FOLLOWING A THREE-PHASE FAULT FOR BOTH FAULT CASES.....	92
FIGURE 3-15: GENERATOR SPEED IN P.U. FOR BOTH FAULT CASES	93
FIGURE 3-16: GENERATORS' POSITIVE-SEQUENCE REACTIVE POWER IN MVAR CHARACTERISTIC FOR BOTH FAULT CASES	94
FIGURE 3-17: GENERATORS' POSITIVE-SEQUENCE ACTIVE POWER (MW) CHARACTERISTIC FOR BOTH FAULT CASES	94
FIGURE 3-18: THE ROTOR ANGLE WITH REFERENCE TO REFERENCE BUS VOLTAGE IN DEGREES FOR BOTH FAULT CASES	95
FIGURE 3-19: MECHANICAL TORQUE IN P.U. FOR BOTH FAULT CASES.....	95
FIGURE 3-20: EXCITATION CURRENT IN P.U. RESPONSE FOR BOTH FAULT CASES	96
FIGURE 3-21: VOLTAGE MAGNITUDE CHARACTERISTICS DURING A 25 S TIE-LINE LOSS	97
FIGURE 3-22: ELECTRICAL FREQUENCY CHARACTERISTICS FOLLOWING A TIE-LINE LOSS.....	97
FIGURE 3-23: GENERATORS' SPEED CHARACTERISTICS FOLLOWING A TIE-LINE LOSS INCIDENT.....	98
FIGURE 4-1: SCHEMATIC DIAGRAM SHOWING THE TRANSMISSION SYSTEM BETWEEN THE MERAPI AND MABOTE SUBSTATIONS	108
FIGURE 4-2: FREQUENCY IN HZ FOR LOAD-SHEDDING STUDY CASES 1 TO 5	110
FIGURE 4-3: REACTIVE POWER (MVAR) FOR LOAD-SHEDDING CASES 1 – 5.....	110
FIGURE 4-4: COMPARISON OF ACTIVE POWER (MW) GENERATION FOR STUDY CASES 1 TO 5.....	111
FIGURE 4-5: COMPARISON OF BUSBAR VOLTAGE IN PER UNIT AT MABOTE SUBSTATION FOR STUDY CASES 6 TO 8	113

FIGURE 4-6: COMPARISON OF REACTIVE POWER (MVAR) DEMAND ON THE HYDRO GENERATORS FOR STUDY CASES 6 TO 8.....	113
FIGURE 4-7: COMPARISON OF ACTIVE POWER (MW) DEMAND ON THE HYDRO GENERATORS FOR STUDY CASES 6 TO 8.....	114
FIGURE 4-8: COMPARISON OF FREQUENCY IN HZ FOR STUDY CASES 6 TO 8.....	114
FIGURE 4-9: FREQUENCY IN HZ DURING A THREE-PHASE BUSBAR FAULT ON TWEESPRUIT SUBSTATION	118
FIGURE 4-10: THE VOLTAGE IN PER UNIT DURING A THREE-PHASE BUSBAR FAULT ON TWEESPRUIT SUBSTATION	118
FIGURE 4-11: THE ROTOR ANGLE WITH REFERENCE TO THE REFERENCE BUS VOLTAGE IN DEGREES DURING A FAULTED CONDITION ON TWEESPRUIT SUBSTATION.....	119
FIGURE 4-12: COMPARISON OF THE MEASURED EXCITATION CURRENT VERSUS IEEE RECOMMENDED LIMITS....	120
FIGURE 4-13: SCHEMATIC DIAGRAM SHOWING THE FAULT ON THE TRANSMISSION SYSTEM BETWEEN EMB AND TWEESPRUIT SUBSTATIONS.....	122
FIGURE 4-14: CRITICAL FAULT CLEARING TIME DURING THE THREE-PHASE FAULTS ON CIRCUIT 1 WHEN CIRCUIT 2 WAS IN-SERVICE	123
FIGURE 4-15: ROTOR ANGLE RESPONSE TO DIFFERENT FAULT CLEARING TIMES FOR A FAULT ON THE TWEESPRUIT LINE.....	124
FIGURE 4-16: CRITICAL CLEARING TIMES PROFILE FOR THREE-PHASE FAULTS – LINE 2 OUT-OF-SERVICE.....	125
FIGURE 4-17: THE SCHEMATIC DIAGRAM SHOWING PART OF THE LESOTHO TRANSMISSION SYSTEM WITH BREAKERS TRIPPED ON THE THREE-PHASE FAULT	126
FIGURE 4-18: THE VOLTAGE IN PER UNIT DURING A THREE-PHASE FAULT ON THE MABOTE-MAPUTSOE TRANSMISSION LINE.....	127
FIGURE 4-19: BLOCK DIAGRAM SHOWING THE SUBSTATIONS THAT CONNECT DIRECTLY TO MABOTE SUBSTATION	128
FIGURE 4-20: POSITIVE SEQUENCE VOLTAGE IN PER UNIT DURING A DOUBLE-PHASE SHORT-CIRCUIT ON THE MABOTE 33 kV BUSBARS.....	130
FIGURE 4-21: FREQUENCY IN HZ DURING A GENERATOR TRIP EVENT	131
FIGURE 4-22: VOLTAGE IN PER UNIT DURING A GENERATOR TRIP EVENT.....	131
FIGURE 4-23: IMPACT OF SVC ON THE CRITICAL FAULT CLEARING TIME.....	132
FIGURE 4-24: COMPARISON OF THE EXCITATION CURRENT PROFILE DURING DYNAMIC CONDITIONS FOR BOTH STUDY CASES	133
FIGURE 4-25: COMPARISON OF THE ROTOR ANGLE CHARACTERISTICS DURING DYNAMIC CONDITIONS FOR BOTH STUDY CASES	133
FIGURE 4-26: THE SAFE BREAKER CLOSING LIMITS FOR SUCCESSFUL SYNCHRONISM	135
FIGURE 4-27: THE SYSTEM LOADING LIMITATIONS FOR SAFE RE-ENERGISING OF THE TIE-LINE TO JOIN THE TWO SYSTEMS	136
FIGURE 4-28: THE ACTIVE POWER SWING LIMIT FOR SUCCESSFUL SYNCHRONISATION OF THE TWO SYSTEMS	137
FIGURE 4-29: COMPARISON OF ACTIVE POWER PROFILE FOR DIFFERENT LOAD RESTORATION APPROACHES	138

LIST OF SYMBOLS

P_{SR}	Power transfer from the source to the load
δ	Power angle
λ	Flux linking generator windings for phases a , b and c respectively
ω	Angular velocity
H	Inertia constant
T_m	Mechanical torque
T_e	Electrical torque
K_d	Damping factor representing the effect of damper windings
T_m	Mechanical torque
P_i	Injected power at node i
Q_i	Injected reactive power at the node i ,
V	System voltage
F_t	Moving average trend
K_{pf-i}	Frequency bias
C_n	Line-to-neutral capacitance in a three-phase overhead line
K_{pf}	Active frequency dependency factor
K_{qf}	Reactive frequency dependency factor
t_{cr}	Critical clearing time
t_f	Actual clearing time
K_{time}	Transient stability margin

P_M	Peak pre-fault power angle curve
r_1	Peak of power angle curve ratio of the faulted circuit to P_M
r_2	Peak of power angle curve ratio to P_M with fault cleared
I	Current in amperes
T_{ags}	Generator acceleration time constant
K_e	Exciter gain
T_e	Exciter time constant in seconds for the first-order system representing the exciter
V_{fd}	Field voltage in per unit (pu)
ef	Regulator output
η	System efficiency
J	Moment of inertia in kg for the rotating masses
τ_j	Time constant
f_o	Initial frequency (Hz)
t	Time in seconds
f_t	Frequency during the dynamic condition following load-demand change

LIST OF ABBREVIATIONS

AC	Alternating current
ACE	Area control error
AVR	Automatic voltage regulator
CBD	Central business district
CFCT	Critical fault clearing time
DC	Direct current
EDM	Electricide de Mocambique
EMB	Eskom Maseru Bulk
EMF	Electromotive force
FCT	Fault clearing time
FLS	Fast load-shedding
G	Generator
GMR	Geometric mean radius
HV	High voltage
Hz	Hertz
I	Current
IEEE	Institute of Electrical and Electronic Engineers
kV	Kilo volt
LEC	Lesotho Electricity Company
LEWA	Lesotho Electricity and Water Authority
LFC	Load frequency control
LHDA	Lesotho Highlands Development Authority

LV	Low voltage
MVA	Mega volt-amperes
MW	Mega watt
Nm	Newton meters
OLTC	On-load tap changer
P	Active power
PI	Pi
PQ	Load buses
PSS	Power system stabiliser
PV	Voltage controlled buses
Q	Reactive power
RLC	Resistor inductor and capacitor
ROCOF	Rate-of-change-of-frequency
SA	South Africa
SAPP	South African Power Pool
SIL	Surge impedance loading
STATCOM	Static compensator
SVC	Static var compensator
UFLS	Underfrequency load-shedding
V	Voltage
V-P	Voltage power relationship
Z	Impedance

CHAPTER 1 INTRODUCTION / BACKGROUND

In this *Chapter*, the aim is to introduce the Lesotho power system and the problems experienced in operating its network during large transients. A model based on the Lesotho power system is used to examine and analyse the effects of dynamic load-shedding on the system. In the operation of the power system there are various abnormalities that the system is exposed to, such as: loss of generators and tie-lines, line tripping, non-system related faults and other disturbances, which threaten the stability of the power system. During these system anomalies, active and reactive power flow are affected, which in turn affect the system voltage and frequency compliance.

1.1 Background

Lesotho's power network has a combined generation capacity of 72 MW, which consists of three generator sets at 'Muela Hydropower Station, each rated at 24 MW. The 72 MW generating capacity is not enough to meet the power supply demand of approximately 150 MW. To meet the shortfall, the country imports additional power from Eskom and Mozambique (transported via Eskom's network) through bilateral agreements. While the intention of the additional power is to meet Lesotho's power demand, incidents that occur in the system impede this objective. The growing power demand trend is an indication that this network will continue to depend on surplus power generation from the neighbouring states for surplus power, unless new generation sources are developed.

Under normal conditions, Eskom (and other networks that form the grid) provides both additional active and reactive power to meet the demand. When the tie-lines trip, the network collapses due to overload. The concentration of the bulk of the system's load is in Maseru, the capital city of Lesotho, which draws power from Mabote substation. The failure of the tie-line, regardless of the cause, has serious economic consequences due to loss of production and interruptions to essential services. The existing load-shedding is based on the voltage violations and the utility operates and manages the scheme at 66 kV and 11 kV.

In recent years, some events on the 132 kV tie-lines led to blackouts in the Lesotho power system (see Table 1-1). The occurrence of these events resulted in revenue loss on the part of the utility and had a negative impact on the national economy. This study aims to produce dynamic load-shedding outputs in which dropping blocks of loads minimises the occurrence of the system collapse condition. The utility currently has neither an automatic load-shedding scheme that focuses on frequency violations nor any control on the grid frequency or its management.

Table 1-1 – A list of recent blackouts in Lesotho.

Date of event	Duration (Hours)	Cause of event	Areas affected
8 th May 2016	0.4 hours	Switching error on the 132 kV incomer breakers	Network supplied through Eskom Maseru Bulk transmission line
16 th March 2018	Three hours	Deficit in import power because of maintenance on Eskom system	Network supplied through Eskom Maseru Bulk transmission line

There is no event triggered load-shedding scheme implemented at 132 kV to enable automatic disconnection of pre-selected loads triggered by interruption of supply on the 132 kV tie-lines. This research endeavours to simulate an underfrequency load-shedding scheme that is event activated to load-shed a pre-selected load and forces the system to transit into healthy island operation. The addition of controllers for exciters and governors to model the three generators during island operation shall aid system behaviour analysis for the period of separation of the two systems and during short-circuit conditions on either the transmission lines or on the busbars.

1.2 Problem statement

This research investigates the risks associated with the sudden changes in power supply resulting in frequency changes. The investigation also delves into factors that affect system stability under dynamic conditions and so provide means of minimising the chances of system collapse during loss of the Eskom-Lesotho tie-line.

1.2.1 Sub-problems

Based on the problem statement, the identified sub-problems are:

1.2.1.1 Frequency stability

This refers to imbalance in active power between power generated and the loads resulting in frequency abnormalities in the system. Frequency control for the Lesotho power system is reliant on Eskom and other networks forming the grid, thus when the tie-lines are lost, frequency stability is challenged and this will be investigated.

1.2.1.2 Voltage variations

Increased voltage drops during system disturbances due to system impedance changes - there are currently no installed reactive power compensation units at 132 kV or down to 11 kV. The voltage drops because of the overloading on the power network and thus results in unnecessary system losses. This research investigates dynamic variations in reactive power during system disturbances that hinder voltage support provided by the hydropower station.

1.2.1.3 Underfrequency load-shedding scheme (UFLS)

Control of energy mismatches in the system that occur due to insufficient generation both during the grid connection and in island operation are controlled predominantly through underfrequency load-shedding. The existing load-shedding scheme operates at sub-transmission voltage level; this hamper automatic measurers to safeguard power transmission during tie-line losses. This study tests an event-triggered underfrequency load-shedding technique to limit system overload and to minimize the risk of uncontrolled separation, loss of generation or system blackout.

1.3 Objectives

The main objectives of the study are to:

- Simulate past recorded incidents that caused a collapse in system frequency;
- Analyse the system response following faults on the system, including the loss of tie-lines;
- Analyse the effect of excitation systems for the voltage and reactive power control;
- Analyse the effect of governor systems on the active power and frequency control;
- Design an underfrequency load-shedding scheme that will disconnect a pre-selected portion of the load using various load-shedding techniques;
- Analyse the system stability during and after load-shedding operation and in islanding mode;
- Determine the need for reactive power for voltage support in the network during the system disturbances, and
- Investigate the requirements for safe closing of the tie-line breakers.

1.4 Benefits of study

While power system behaviour under dynamic conditions is a broad topic, this study aims to benefit stakeholders in one or more of the following ways:

- To increase knowledge of system frequency stability margins;
- To determine the optimal corrective actions required for contingency scenarios;

- To understand the load-shedding plan and source decoupling;
- To understand the impact of dynamic reactive power compensation;
- To increase knowledge on apportionment of load shed per station during different load-shedding stages;
- To determine the under- and overfrequency load-shedding scheme settings;
- To increase knowledge on the extreme conditions during which the tie-line breakers can safely close to reconnect the two systems, and
- To determine a plan for a load reconnection sequence or load transfer or both.

The benefits described above will contribute to the creation of a high-level understanding of the Lesotho power system in dealing with dynamic behaviour during large system disturbances. The results of this study will be useful in the collective discussions by both the power supply utilities (the Lesotho Electricity Company (LEC) and the Lesotho Highlands Development Authority (LHDA)) on general power system improvements that can benefit the country in future. If the recommendations of this study are implemented the number of system blackouts will reduce significantly. This study will also be a stepping stone for further studies on the Lesotho power system stability, such as voltage stability and detailed mechanical behaviour of the generators during dynamic conditions.

1.5 Delimitation of study

The following will neither be covered nor discussed in this study:

- The root causes of mechanical failures on the generators (i.e. breaking of shafts of rotating machines and speed reducers as well as damage to coils);
- Destruction or pre-mature wear of electrical equipment due to thermal effects (i.e. abnormal temperature rise caused by overloading);
- Load imbalance;
- Fast network transients (10 μ s to 200 ms) such as lightning and switching surges, and
- Cascading of overload trips in which the feeders may trip because of load transfer from other feeders.

1.6 Method of investigation

This dissertation explores different alternatives for optimizing power transfer under dynamic conditions by applying different load-shedding techniques through the dropping of pre-selected loads from the system. Furthermore, this study also computes the load flow solution to establish the magnitude of the bus voltages, branch power factors, currents, and the power flow throughout the electrical system. The steady state condition of the system is examined by simulating past incidents that led to system collapse or part thereof, the simulation results are discussed as well

as the possible measurers that could have been taken to control the situation. Figure 1-1 summarizes the investigation method as well as the sources of information used for the different stages of the investigation.

Because the Lesotho power system does not have reactive power compensation during island operation, this study undertakes an investigation of the use of a static var compensator (SVC) system for installation at Mabote substation, with the objective of controlling reactive power flow during transition into island operating mode. The faults are simulated on the system either on the tie-lines or on the Eskom Maseru Bulk (EMB) substation to cause a mismatch in the supply and demand, thus forcing the system to transit into island mode. During islanding, the dynamic response triggers such as the short-circuit events are defined to evaluate the synchronous generator and load response. Figure 1-1: Summary of the study process flow summarises the research process in the evaluation of the dynamic stability analysis for the Lesotho power system.

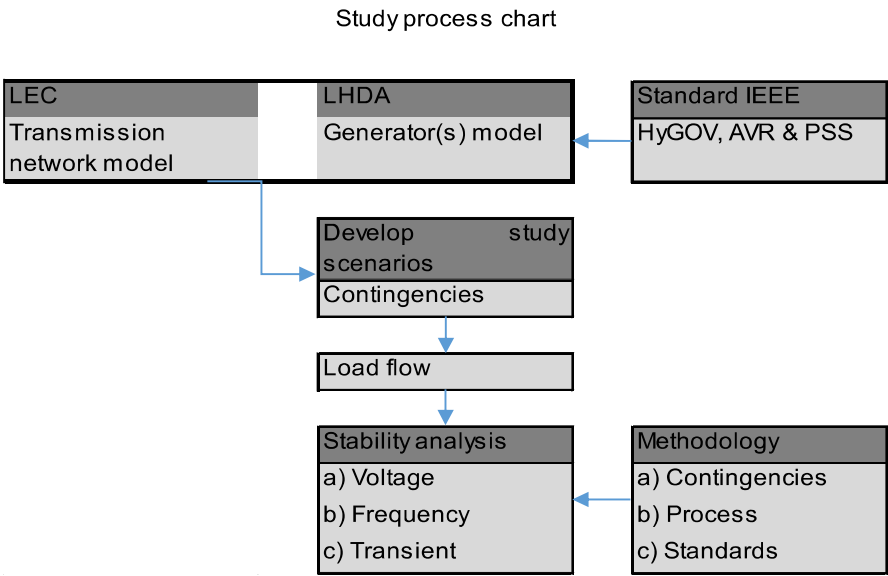


Figure 1-1: Summary of the study process flow

The existing load-shedding is applied at the distribution voltage level in the form of voltage under-voltage load-shedding, but not at the sub-transmission level, as such, there is no specific system in place to address the event-triggered perturbations at the 132 kV transmission line. This study explores different load-shedding techniques to stabilize the grid during the island operation. The simulations’ results from various load-shedding schemes as well as the generator response to load changes will be analysed.

1.7 Structure of the report

Chapter 2 reviews the literature that is pertinent to power system stability. The chapter discusses various elements of the power system, such as overhead lines and transformers, including their

characteristics under steady state conditions and their role in the operation of the system with relevance to system dynamic conditions. The discussion extends to the relationship between real power and frequency and in what way the two interact under system mismatch conditions. Furthermore, this chapter covers the different reactive power compensation techniques and the modelling of the selected optimum solutions with respect to the system size. It continues to examine the generators' behaviour, including controls in the excitation system under perturbed conditions. This review also investigates the characteristics of frequency deviation under different control options, such as primary and secondary control. Lastly, the chapter details a study of various underfrequency load-shedding techniques employed for various stages, following a mismatch in the supply and demand.

In *Chapter 3* the crux of the discussion focusses on the operation of selected models for the simulation of faults on the tie-line and on the selected busbars and on the testing of the system transient stability during faulted conditions. The discussion also encompasses a study performed on load flows. The settings for various excitation system controls considering the dynamic controller, the automatic voltage regulator (AVR) and the power system stabilizer (PSS) are presented and discussed. The chapter also provides and investigates the selected governor system and settings. The chapter also includes illustrations of the system behaviour during a fault on either the tie-line or on the selected busbars that compromise the transient stability margin and eventually lead to complete system collapse, because of either voltage or frequency instability. This chapter concludes with a brief reflection on past events that triggered underfrequency instability, a simulation of the events that caused a system collapse and a discussion of the results including the contingencies.

Chapter 4 starts with simulations of the impact of dropping different amounts of load for different options of load-shedding during dynamic conditions. It continues with an examination of the settings of the UFLS protection relay settings at different load-shedding stages and a substantiation of their time delays. The simulation of contingencies included loss of the tie-lines, three-phase faults on the busbars, asymmetrical faults on the critical transmission lines and tripping of a single generator resulting in abrupt increase in demand during island conditions. The results of these simulations are plotted and analysed to assess the system stability limits.

Chapter 4 also discusses the load reconnection sequence after successful islanding and it examines the various reloading conditions with the aim of evaluating the impact on the system stability. During the reconnection of the tie-line breaker, this chapter tests the extent to which the requisite parameters for synchronising can permit safe closing of the tie-line breaker. The test extends to extreme conditions within which the tie-line breaker can close successfully and the results are plotted to establish safe operating limits.

In Chapter 5 recommendations are made for stakeholders (LEC or LHDA). It also details the conclusions obtained through the degree of success of the study and establishes whether the research has achieved its objective.

The annexure of this dissertation comprises of larger diagrams and illustrations included in the text for better visibility.

CHAPTER 2 LITERATURE REVIEW

This Chapter provides a general literature review conducted to highlight the precincts of the study. To achieve this, the Chapter cites literature sources in the form of published textbooks, technical presentations, and previous reports on the study, articles, presentations, and manuals from different software developers cited throughout the document. The topics covered in the literature review for dealing with the dynamic load-shedding analysis of power system stability in the Lesotho 132 kV transmission network are:

- Power system stability
- Synchronous generators
- Generator excitation system
- Turbine governor systems
- Load-flow study
- System losses
- Active power and frequency control
- Reactive power and voltage control
- Underfrequency load-shedding, and
- Dynamic system restoration.

The section on power system stability examines the disturbances occurring in the power system and discusses the electromechanical oscillations induced. The system oscillations (power swings) need damping to maintain the system stability. The load-flow study is carried out as a prerequisite for advanced studies, including dynamic load-shedding, considering the assumed balanced system, or unbalanced system in some cases, to evaluate the system's stability in a three-phase environment. The blocks of loads used for load-flow studies are resistor, inductor, and capacitor (RLC) circuits. Using a high-level method of calculating the power system losses that also minimises generation costs, optimises delivery of power to the end-users and hence minimises the power system losses. The discussion continues to exhaust the active power control techniques utilised in the industry, which leads to a selection of favourable methods.

In power generation, transmission and distribution the reactive power reserves of the synchronous generators are used as means of controlling the voltages at various nodes, including reactive power exchange with the external grid (Eskom). Underfrequency load-shedding is employed to disconnect pre-identified loads as contributory to the non-convergence of the power network to salvage the system from a complete collapse because of instability.

Defined broadly, power system stability is the property of a power system that enables it to remain in a state of operating equilibrium under normal operating conditions and to regain an acceptable state of equilibrium after a perturbation [1]. When a power system operates in a steady state, the total power generated is equal to the system load plus losses, in this state the system frequency is constant at the nominal frequency. The system is stable if it can survive numerous disturbances of a severe nature such as short-circuits on the transmission system, the loss of large generators or load or loss of the tie-line etc. [1]. The moment load exceeds generation, the frequency starts to drop and when the deficit is large enough, variance in load and demand can lead to system collapse.

In the classification of a robust system, the definition of its robustness is derived from the system's ability to maintain stable operation under normal and perturbed conditions. Generally, system stability is one of the main determining factors of power system, frequency, and voltage stability [1]. In view of constraints attributable to capacity, there is a need for monitoring frequency on the power system to aid the balance between power generated and system load.

2.1 Power and frequency relationship

As load increases, the frequency decreases, similarly, as generation increases the frequency improves. Under normal operating conditions, the acceptable frequency varies between 49.80 Hz and 50.20 Hz, while the nominal frequency is 50.0 Hz [2]. The interpretation of the frequency droop characteristic is:

- When the system frequency falls from ' f_0 ' to ' f ', power output of the generating unit can increase from ' P_0 ' to ' P ' as depicted in Figure 2-1;
- A falling system frequency indicates an increase in load and therefore requires more active power generation. In the case of multiple parallel units with the same droop characteristic, they can respond to the fall in frequency by increasing their active power outputs simultaneously, and
- The increase in the active power output of the generators will counteract the reduction in frequency and the units will settle the active power outputs and frequency at a steady-state point on the droop characteristic. The droop characteristic therefore allows multiple units to share load without the units competing to control the load (called "hunting").

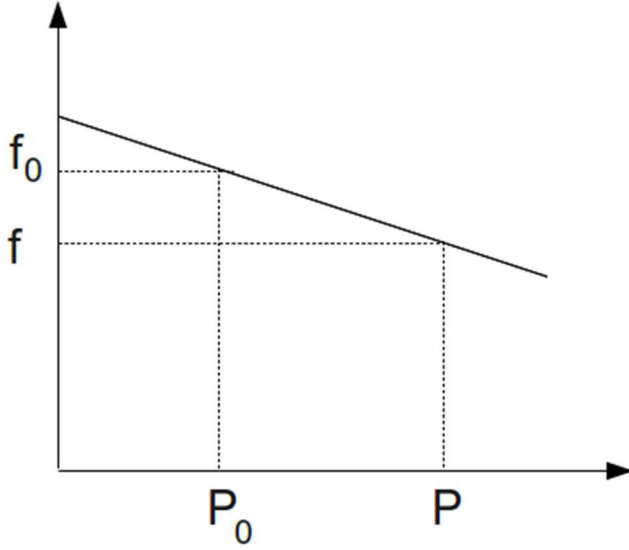


Figure 2-1: Frequency versus power response characteristics under load mismatch conditions [1]

The analogy presented in Figure 2-1 has effects on the active power flow as is evident from the power flow equation (Equation 2-1).

$$P_{SR} = \frac{V_S \times V_R}{X_{CR}} \times \sin \delta_{SR} \quad (2-1)$$

From equation 2-1, the largest factor in determining the amount of power transfer is the power angle (δ). The power angle changes when there is a change in acceleration or retardation relative to the existing steady state condition. There must be relative acceleration translating into an increase in frequency for power transfer to take place between two points [3]. For incidents in which negative damping of certain swing modes occur, regardless of the adequacy of excitation level under the disturbed condition, the resulting oscillations of these incidents can grow significantly to a level where it threatens the secure operation of the power system.

Under perturbed conditions, the electromechanical oscillations fall under four main categories, viz:

- Local oscillations
- Interplant oscillations
- Interarea oscillations, and
- Global oscillations.

2.1.1 Local oscillations

This phenomenon takes place between any individual generating unit in the same area and within the station against the rest of the generating station and results in the oscillation of the rest of the generating station against that of the entire power system. These types of

oscillations (power swing oscillations) require enough damping to maintain power system stability. A failure to achieve adequate damping may result in oscillations of the generator rotor angle that increase in amplitude until the system loses stability [1]. The oscillations occur within the frequency range of 0.8 Hz to 4 Hz [4].

2.1.2 Interplant oscillations

Interplant oscillations is another form of oscillation. It occurs between the units installed in the same generating station. They occur more frequently on the electrically close-coupled plant in the generating station within the frequency range of 1 Hz to 2 Hz [4].

2.1.3 Interarea oscillations

This type of oscillation occurs between two major groups of the generation plant [4]. In the case of the Lesotho power system, this could occur between the Eskom network (referred to as the grid) and the 'Muela generators. The extent of interarea oscillations ranges between 0.1 Hz and 1 Hz [4]. This occurrence is comparable to a group of machines that swing together, but in opposition to another group of machines in the power system. Given the nature of these oscillations, when they occur, both the load and the generators take part in the oscillations.

2.1.4 Global oscillations

Global oscillations are characterised by oscillations of all the synchronous generators connected in an isolated system. The occurrence of this type of oscillation is further characterised by the common in-phase oscillations in the frequency range not exceeding 0.3 Hz [1]. This type of oscillation occurs mostly during the disconnection of a large load from the system or a load rejection on a large generating unit in big power systems.

2.2 Synchronous generators

Synchronous generators are the major source of commercial electrical energy. Mechanical energy output from steam and hydro turbines converts mechanical energy into electrical power for various uses at different voltage levels [4]. The main component of a synchronous generator is the rotor; this is the rotating part in which field excitation in the form of direct current (DC) (see Figure 2-2) is applied.

The direct current in the field windings of the rotor induces a magnetic field, which is stationary in nature by rotating relative to the rotor; this rotation of the magnetic field induces voltage. The increase in generator terminal voltage is proportional to the increase in the magnetisation or the

excitation current. The voltage regulator keeps the generator terminal voltage within the limits, and forms part of the excitation system.

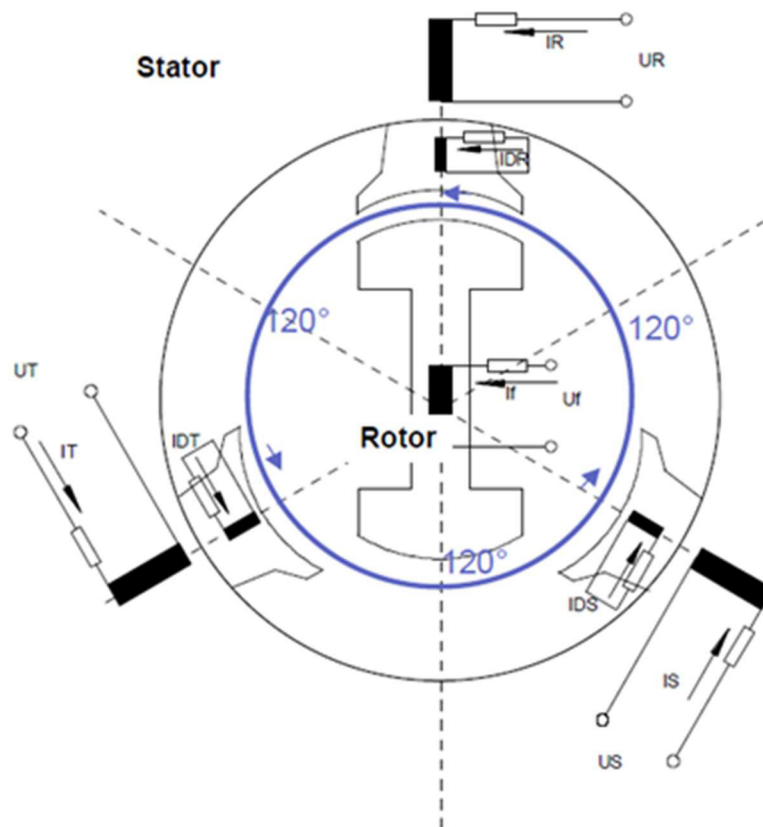


Figure 2-2: D-Q axis presentation of three-phase synchronous machines [5]

In addition, the configuration of the synchronous machines comprises of three stator windings: the stationary winding, one field winding for excitation purposes and damper windings [6]. These windings are coupled by a magnetic field generated when the system is excited through the excitation system. Figure 2-3 illustrates the relationship between the windings emphasising the inductance, voltages, and flux linkages.

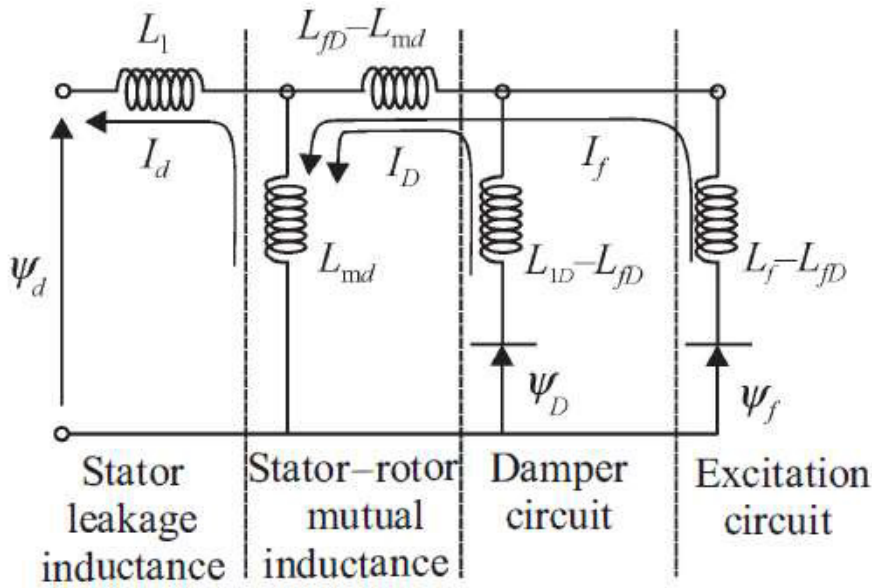


Figure 2-3: The equivalent circuit showing the windings per unit leakage inductances [7]

The flux, which magnetically links the windings, is dependent on the rotor position. Equation 2-2 mathematically expresses the excitation process that produces the terminal voltage.

$$\begin{cases} v_a(t) = -R_a i_a(t) + \frac{d\lambda_a(t)}{dt} \\ v_b(t) = -R_b i_b(t) + \frac{d\lambda_b(t)}{dt} \\ v_c(t) = -R_c i_c(t) + \frac{d\lambda_c(t)}{dt} \end{cases} \quad (2-2)$$

Where

R_a, R_b and R_c is winding resistance in ohms for phases a, b and c respectively

i_a, i_b and i_c is the stator current flowing out of the generator terminals for phases a, b and c respectively and therefore assumed to be positive when flowing out of the machine

λ is flux linkage linking the various windings for phases a, b and c respectively

The voltage generated by the synchronous generator is dependent on the position of the rotor with respect to the flux linkage linking various windings. The rotor of the synchronous generator can be either cylindrical shape (also called round rotor) or salient in shape, like that represented in the synchronous machine in Figure 2-2. The stator modelling is done through the leakage reactance and the armature reaction, while the rotor is modelled using both the field winding and damper windings. Ideally, the distribution of the magnetic field flux in the air-gap, the mutual inductances and inductances between the stator and the rotor are sinusoidal in nature and vary in angle, which defines the rotor position.

The excitation circuit supplies DC to produce a magnetic field that is stationary relative to the rotor, but in motion relative to the stator for which the speed of rotation is equal to the rotor speed [8]. When the rotor is excited with current from the excitation circuit, it produces flux in the air-gap space that rotates at a constant angular velocity (ω). The flux linkage resulting from the excitation process varies with the rotor position (ωt) in which the magneto-motive force (mmf) axis aids measuring of rotational speed relative to the coil magnetic axis [9].

The stator windings form the stationary part of the synchronous machine. The three stator windings are placed 120° apart. Mutual inductance occurs between the stator and rotor windings. The mutual inductance that occurs between the rotor and the stator changes with respect to the rotor position; it is at a maximum value when the rotor and stator axes align and are rotating in the same direction [10]. The values are therefore at a minimum when the axes of rotor and stator are in opposing directions in which case the inductance is at a minimum at zero as indicated in Figure 2-4.

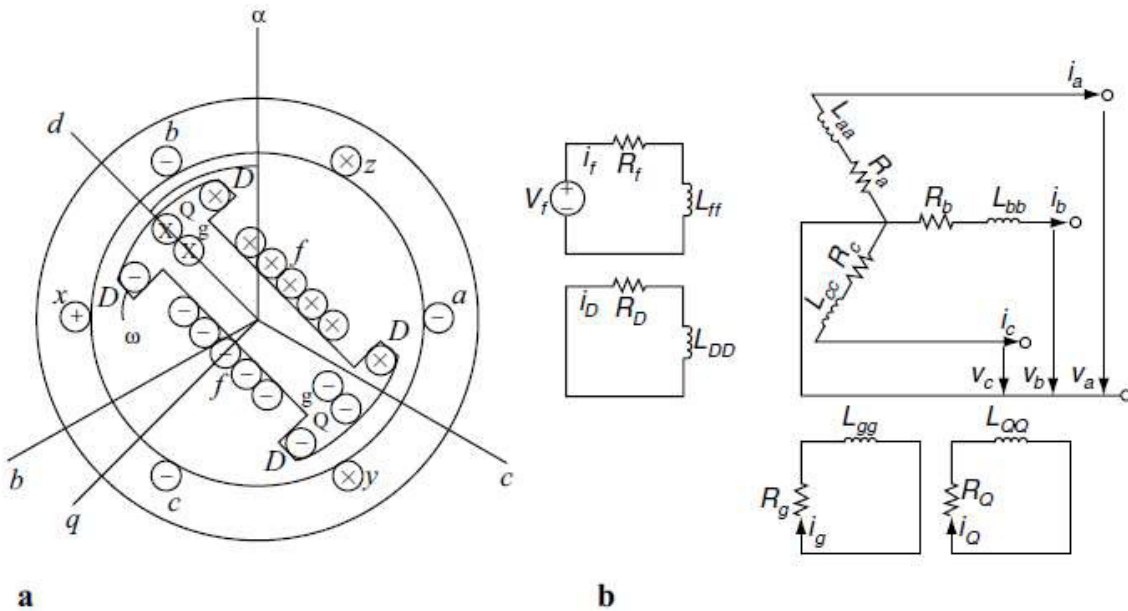


Figure 2-4: The windings of synchronous generator and their axes [11]

Equations 2-3 and 2-4 depict the synchronous generator mechanical system in simple form.

$$\Delta\omega = \frac{1}{2H} \int_0^t (T_m - T_e) dt - K_d \Delta(t) \quad (2-3)$$

$$\omega(t) = \Delta\omega(t) + (\omega_0)' \quad (2-4)$$

Where

$\Delta\omega$ is speed variation with respect to speed operation

H is the constant of inertia

T_m is mechanical torque

T_e is electro-magnetic torque

K_d is the damping factor representing the effect of damper windings

$\omega(t)$ is the mechanical speed of the rotor

ω_0 is speed of operation in per unit

Thus, the effect of the rotating mass of the generator at the given radius defines the assessment of rotating inertia of the generator (see equation 2-5).

$$J = \text{radius of rotation squared} \times \text{mass} \quad (2-5)$$

Where

J is expressed in units of kg-m²

$Mass$ is expressed in kilograms

$Radius$ of the rotor is expressed in meters

In a multi-machine environment, each generating unit contributes towards the total additional power required relative to the system inertia. Thus, individual generator contribution to the power balance is therefore proportional to the inertia or acceleration time constant of each generator set. This relationship is presented mathematically in equations 2-6 and 2-8.

$$P_i = P_{i-dispatch} - \Delta P_i \quad (2-6)$$

Where

P_i is the generator modified active power

$P_{i-dispatch}$ is the generator initial active power dispatch

ΔP_i is the active power change of each generator to be determined and is commensurate with the corresponding inertia gain (K_{pf-i}). The frequency variation in this regard is expressed as follows:

$$\Delta P_i = K_{pf-i} \times \Delta f \quad (2-7)$$

Where

$f\Delta$ is the total frequency deviation

K_{pf-i} is the inertia gain parameter of generator i , which can be articulated as

$$K_{pf-i} = J \times \omega_n \times 2\pi \quad (2-8)$$

With

$$J = S_n \times \frac{T_{ags}}{\omega_n^2} \quad (2-9)$$

Where

J is the moment of inertia

ω_n is the rated angular velocity

S_n is the generator nominal apparent power and

T_{ags} is the S_n rated acceleration time constant

Therefore, it is crucial to pair the generators considering inertia and / or the acceleration time constant to identify and match each generator's active power contribution to the system to compensate for frequency deviations. Under these conditions and depending on the power balance, the steady state frequency will settle at a new operating value and adjust to the nominal value as the system dynamics subside.

Figure 2-5 [12] presents the summary of frequency deviation following perturbation in a system leading to an unbalance in active power. With reference to Figure 2-5, the various characteristics together with the related terminology are described in 2.6.1 to 2.6.4.

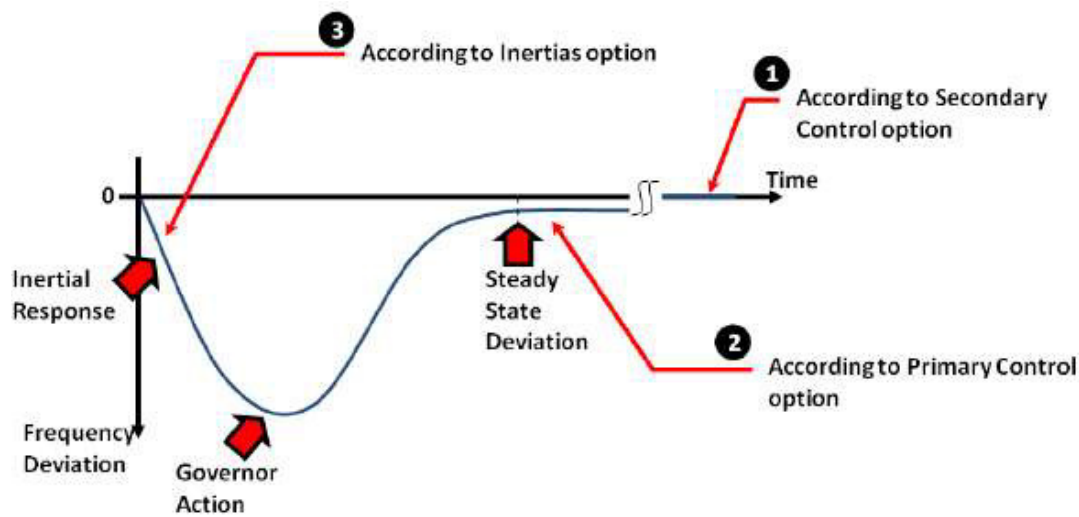


Figure 2-5: Characteristic of frequency deviation following active power unbalance [12]

2.3 Generator excitation system

The main function of an excitation control system includes keeping the generator terminal voltage constant under steady state conditions and adjusted to within reasonable limits under dynamic conditions as the generator output varies with continuous loading capability [13]. The generator excitation system consists of the exciter and automatic voltage regulator (AVR), these being the requisite subsystems required for the supply of the generator field with DC current. The other function of an excitation system is to accomplish the control and protective functions essential for satisfactory enhanced operation of the power system. The control function encompasses the bus voltage control and the reactive power flow, and boosts system stability [1].

In the event of a fault on the overhead lines for example, the excitation system with high ceiling voltage and fast response benefits the system stability by applying field forcing, thus boosting the terminal voltage to within allowable limits with respect to declared nominal voltage. The sustenance of the terminal voltage under fault conditions is dependent on the clearing speed of the protection system as well as the limit of the ceiling voltage capacity.

2.3.1 Limiting factors in the operation of an excitation system

In varying the magnitude of the DC field current, the synchronous machine terminal voltage is controlled. The transient stability can be improved by controlling the field voltage output during and after a major disturbance to within its ceiling voltage limitations [14]. The ability of the modern exciters to respond instantaneously to system dynamics as well as to having a high field-forcing capability, enhances system stability through fast reaction of stabilizing signals. The limits for generator capabilities under these conditions are:

- Rotor insulation: to protect the rotor from high field voltage in case the voltage exceeds the rated ceiling value;
- Excessive application of field current: protect the windings from excessive heat which can result in the rotor overheating;
- High armature current loading which can result in the stator overheating;
- End of the core's overheating due to under excitation conditions, and
- Overheating due to excessive flux.

2.3.2 Output signals from an excitation system

The output of excitation system supplies the direct current to the rotor windings. The exciter is represented by the transfer function between the exciter voltage V_{fd} and the regulators output ef presented in equation 2-10.

$$\frac{V_{fd}}{ef} = \frac{1}{K_e + sTe} \quad (2-10)$$

Where

K_e is the exciter gain

Te is exciter time constant in seconds for the first-order system representing the exciter

V_{fd} is the field voltage in per unit (pu)

ef is the regulator output

With reference to equation 10, the generator's thermal limits should be exceeded for a limited period only, typically 15 s to 60 s; exceeding these time limits with the intention of keeping the load live would be risky, as the insulation could be damaged [1]. The excitation system is thus vital to contribute to the control of the stator voltage, hence improvement of the power system stability.

2.3.3 Excitation system functional block diagram

The general functional block diagram of the excitation system presented in Figure 2-6 demonstrates the relationship between the various functional blocks. In the event of a fault on the system, the excitation system provides positive field voltage forcing. In doing so, the output current increases to control the terminal voltage.

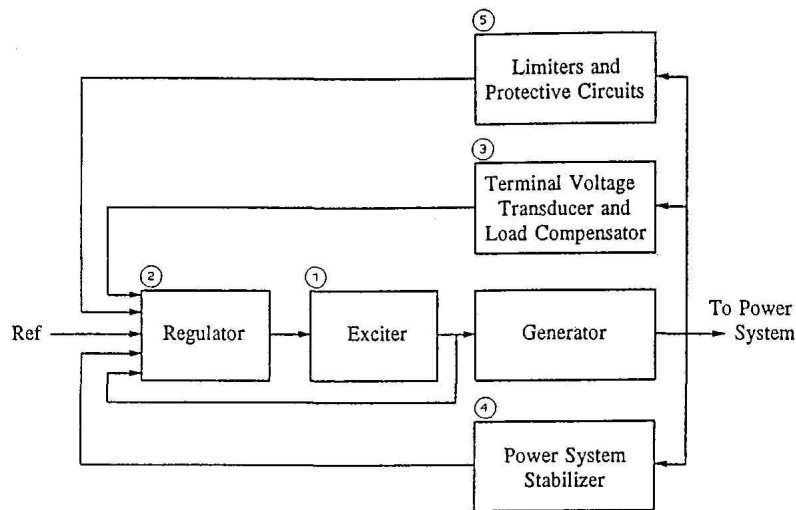


Figure 2-6: Functional block diagram of excitation system [15]

With reference to Figure 2-6, the functions of the various blocks are summarised in Table 2-1:

Table 2-1: Summary of functions of elements that make up the excitation system

Functional block	Function
Exciter	Provides direct current (DC) to the generator field windings
Regulator	Processes the feedback signals and amplifies the input signals to a level that is appropriate for control of the exciter
Power system stabilizer	It provides an additional input signal to the regulator for requisite actions such as damping power system oscillations
Limiter and protective circuit	This function monitors the protection of the circuit and is energised to ensure that the generator capability curve with the associated limits are not exceeded
Terminal voltage transducer and compensator	They monitor the generator terminal voltage and provide the feedback signal required for rectifying when the terminal voltage is outside the boundaries of operation, thus bringing the terminal voltage to within limits

2.3.4 Excitation systems technologies

Modern excitation systems use solid-state components for fast-response and high amplifier gains. The importance of fast-response and high-gain aids the generator to overcome saturation in the event of high demand or fault conditions. They have the capability of rapidly increasing the field generator excitation following an error signal indicating low terminal

voltage on the generator output [16]. This characteristic results in improved critical fault clearing times in the event of faults as the generator output power decreases during the fault condition. The excitation system technologies are categorised into three types, viz:

- DC exciters (either self-excitation technique or separately excited technique);
- AC exciters with rectifier circuits, and
- Static exciters employing semiconductors.

2.3.4.1 DC exciters

This technology uses a DC generator to supply power to the generator field windings by supplying direct current (DC) to the synchronous machine through the slip rings. This may occur in an either self-excited or separately excited system (see Figure 2-7). This technology is not widely used owing to high maintenance costs.

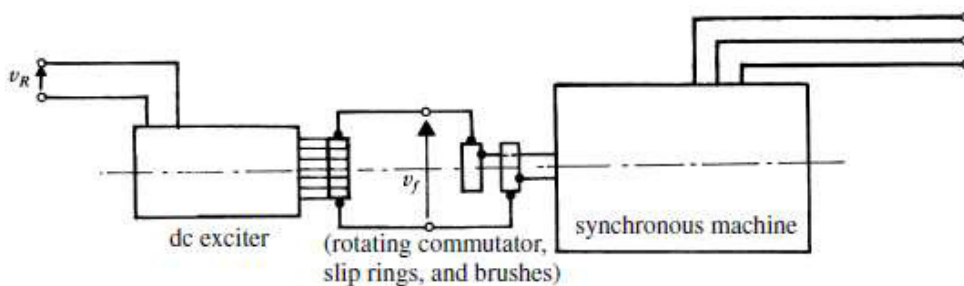


Figure 2-7: General functional block diagram of DC exciter model [17]

2.3.4.2 AC exciters

The output of the AC rectifiers is rectified through the three-phase converters and they rotate on the shafts of synchronous machines. The AC output from the armature windings of the exciter is converted into DC through the use of uncontrolled or controlled bridge rectifiers to supply current to the generator field windings (see Figure 2-8) [1].

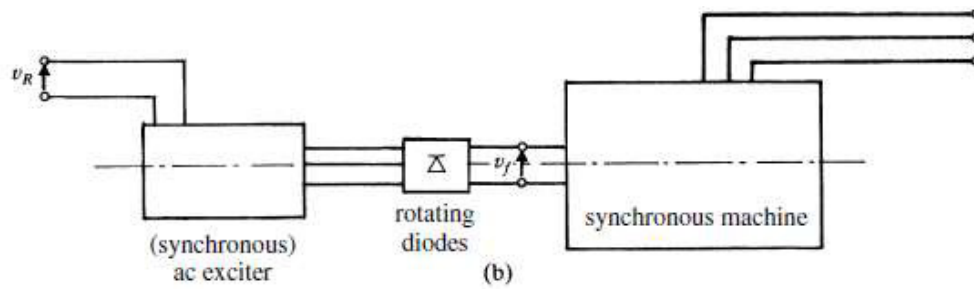


Figure 2-8: Typical functional block diagram of AC exciter model [11]

When the excitation uses the controlled rectifiers to obtain the field current required for excitation, the voltage regulator controls the firing angle of the solid-state devices, thereby controlling the output of the rectifiers to keep the output voltage constant.

2.3.4.3 Static exciters

This technology uses stationery components and supplies direct current directly to the generator field windings through slip rings [17]. Improvement of system stability by employing static exciters to reduce the severity of the machine swings during fault conditions, is a technique that is more advantageous than other existing techniques. Another advantage is that they help to reduce the magnitude of the first swing, thus rendering succeeding swings smaller and less harmful to the system.

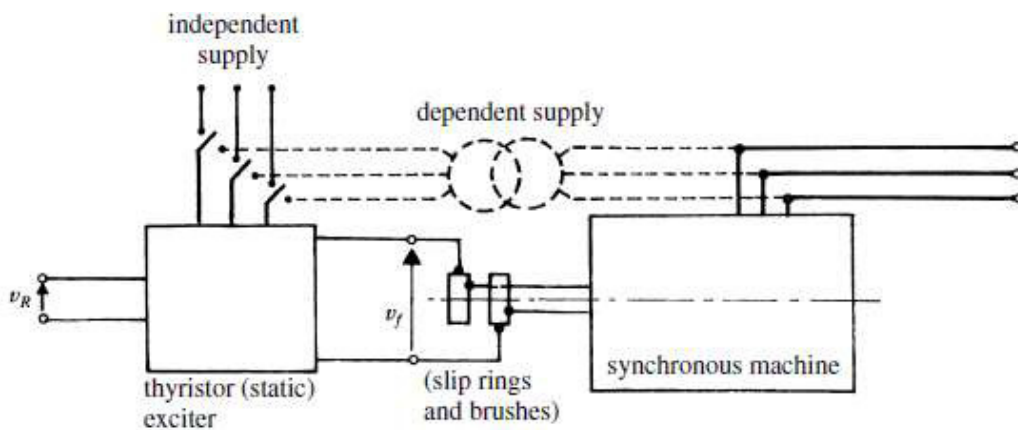


Figure 2-9: Typical functional block diagram for static excitation system [17]

2.3.5 Power system stabilisers

In adding the power system stabilizers to the automatic voltage regulator (AVR), it improves the power system oscillations damping [18]. It is essentially a differentiating element with phase shifting corrective elements whose input signal is in proportion to the rotor speed, the generator output frequency, or the real power output of the generating system. This is

achieved by the use of auxiliary stabilizing signals applied to the AVR to damp power system oscillations, to control the excitation system, hence improve dynamic performance [10].

The controlled signals represent the shaft speed, terminal frequency, and power. With reference to Figure 2-6, the output signal from the power system stabilizer forms part of the input signals to the regulator from where the combined control and regulation takes place.

Under a steady-state condition, the change in voltage (ΔV) only activates the controller to control voltage regulation within the permissible limits. During a transient condition, the generator rotor speed (ω) is not constant, which results in a change in voltage, where after the oscillations in the voltage then require a signal to the active excitation control for damping actions [10].

Under a small signal stability condition, damping of the oscillations improves the system dynamic performance [1].

The oscillations are harmful to the system and create interarea power oscillations. In the case of synchronous generators, field dampers damp the rotor oscillations.

System weakening can occur, when oscillations are not adequately damped in time, hence the requirement for activation of the excitation control system. The typical block diagram showing the connection of the power system stabilizer (PSS) (A) into the power system and its interconnection with the signal sensor; (B) high pass filter; (C) compensation element; (D) amplifier gain; and (E) limiter is presented in Figure 2-10 [10].

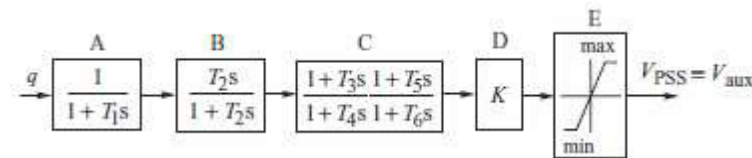


Figure 2-10: Space presentation of PSS relationship with other system functional elements [10]

2.3.6 Generator output voltage

At no-load, the excitation current and rotational speed determine the generator voltage output at the terminals. The flow of the excitation current induces the electromotive force (EMF) in the field windings. The induced EMF therefore opposes the voltage supply that aids the current flow, resulting into a delay in current flowing in the conductor. The induced EMF results in a delay in the form of a phase-angle between the current and the voltage in AC systems. The induced voltage originates from Faraday's law as indicated in equations 2-11 and 2-12.

$$e_a = \frac{d\lambda}{dt} = \omega N\Phi \sin \omega t$$

$$= E_{max} \sin \omega$$

$$= E_{max} \cos(\omega t) - \frac{\pi}{2} \quad (2-11)$$

Where

$$E_{max} = \omega N\Phi = 2\pi f N\Phi \quad (2-12)$$

The phasor diagram (see Figure 2-11) of the synchronous machine illustrates the behaviour of the system under balanced steady-state conditions.

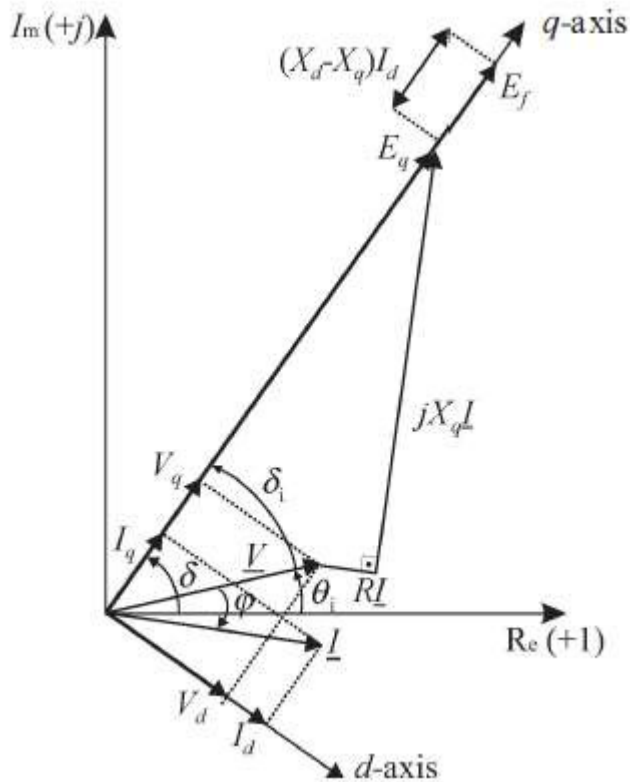


Figure 2-11: Phasor diagram of synchronous machine under balanced steady state condition [4]

From Figure 2-11 it is evident that the rotor angle (δ_i) is the phase shift between the terminal voltage and the electromotive force (EMF), while the phase shift between the terminal voltage (V) and the load current (I) is the power factor angle (φ) [4]. The three-phase quantities are transformed into a two-axis reference frame using Park Transformation.

2.3.6.1 Park transformation

The Park transformation uses the phase voltage quantities, viz V_a, V_b and V_c (see equation 2-13) in terms of the $dq0$ transformation quantities. The modelling of the synchronous machines uses three-phase stator quantities in referral to the rotor. This technique eliminates the time varying inductances by referring the stator and rotor quantities to a synchronous rotating reference frame [9].

$$\begin{cases} V_a = V_d \sin(\omega t) + V_q \cos(\omega t) + V_0 \\ V_b = V_d \sin\left(\omega t - \frac{2\pi}{3}\right) + V_q \cos\left(\omega t - \frac{2\pi}{3}\right) + V_0 \\ V_c = V_d \sin\left(\omega t + \frac{2\pi}{3}\right) + V_q \cos\left(\omega t + \frac{2\pi}{3}\right) + V_0 \end{cases} \quad (2-13)$$

Where

ω is the rotational speed of the rotating frame in rad/s

An inverse of phase transformation (see equation 2-14) is used to compute the voltages in terms of the $dq0$ transformation form.

$$\begin{cases} V_d = \frac{2}{3} (V_a \sin(\omega t) + V_b \sin\left(\omega t - \frac{2\pi}{3}\right) + V_c \sin\left(\omega t + \frac{2\pi}{3}\right)) \\ V_q = \frac{2}{3} (V_a \cos(\omega t) + V_b \cos\left(\omega t - \frac{2\pi}{3}\right) + V_c \cos\left(\omega t + \frac{2\pi}{3}\right)) \\ V_0 = \frac{1}{3} (V_a + V_b + V_c) \end{cases} \quad (2-14)$$

Where

ω is the rotational speed of the rotating frame in rad/s.

In the case of the transformation of current quantities, the line current quantities replace the voltage quantities in equations 13 and 14 by following a similar procedure. The direct axis currents and quadratic axis currents represents the two fictitious DC currents flowing in the two equivalent rotor windings, viz the d-axis winding on the same axis as the field winding and the q-axis winding in quadrature producing the same flux as the stator currents I_a, I_b and I_c . The total power supplied is computed as the sum of rate of change of armature magnetic energy and the power transferred across the air-gap less the armature resistance losses.

2.4 Load-flow study

In a load-flow study, the model of interest is the relationship between non-linear power injections at the various power sources and power demands in the network. Load flow forms the base for

conducting the dynamic conditions studies; while that is so, it does not consider the transient or dynamic conditions of the system. The application of non-linear algebraic equations [11] solves the load flow problem. Thus, the focus of load flow is mainly on the operation of the system under a steady-state condition. In conducting the load-flow study, the evaluated quantities are voltage, angle, active power, and reactive power and once they have been determined the necessary remedial actions are applied to achieve the balance [19].

The basis for analysis of the power system under a steady-state condition or non-faulted conditions is a valid load flow solution. Some of the main application areas for load-flow calculations are:

- Calculations of branch loading, system losses and voltage profiles for system planning and operation under steady-state and dynamic conditions;
- As an aid to the optimisation of load-shedding under dynamic conditions, and
- Calculations of the initial conditions for stability computations and simulations for short-circuit calculations [12].

The formation of load flow includes various elements of the power system such as the generators, transformers, transmission lines and loads connected to the system as indicated in Figure 2-12. Load-flow calculations consider active and reactive power flows for all the connected branches of the power network, the computations include the magnitude and phase angles for all the nodes.

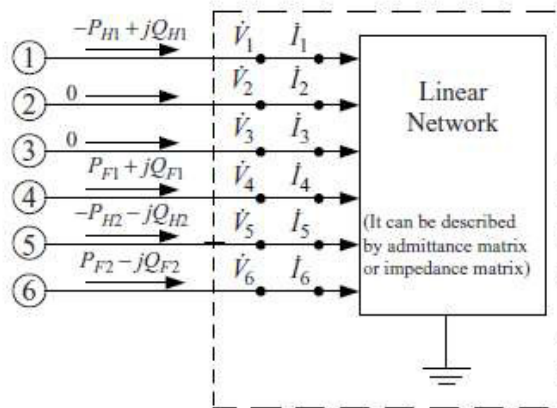


Figure 2-12: Representation of power system components required for load flow [11]

The performance of load-flow studies establishes the relationship between node power and current in the linear system (see equation 2-15) [11].

$$I_i = \frac{P_i - jQ_i}{V_i^*} \quad (2-15)$$

Where

P_i is the injected active power at the node i ,

Q_i is the injected reactive power at the node i ,

V_i is the system voltage

To be able to solve the load-flow problem, two variables should be known, while the others are categorised as the state variables that must be calculated to obtain their actual values.

The criteria for selecting the quantities on buses for computing are as follows:

- Load buses;
- Voltage controlled buses, and
- Slack buses

2.4.1 Load buses (PQ nodes)

At this bus, the known parameters are active and reactive power, while voltage (v) magnitude and the phase angle (θ) remain to be computed [11]. The load draws active and reactive power from the system. The substations are regarded as the PQ nodes, for which the load active and reactive power are constants or known parameters.

2.4.2 Voltage controlled buses (PV nodes)

The known parameters for this bus are voltage magnitude and active power, while the reactive power and voltage angle need to be computed [11]. The buses of the power generation plants function as voltage-controlled buses as a result of their ability to produce reactive power to maintain the system voltage.

2.4.3 Slack buses

This is the reference bus of the power system with constant voltage magnitude and phase angle with infinite active power [11]. For this purpose, the known parameters are voltage (v) and phase angle (θ), while the active power and reactive power values need computing.

2.5 System losses

In operation of the power system, a special consideration determines power losses that occur between the generating stations, transmission system and load buses. Figure 2-13 presents the summary of losses that occur in a system, which can be categorised into the following:

- No-load losses;
- On-load losses, and
- Regulation losses.

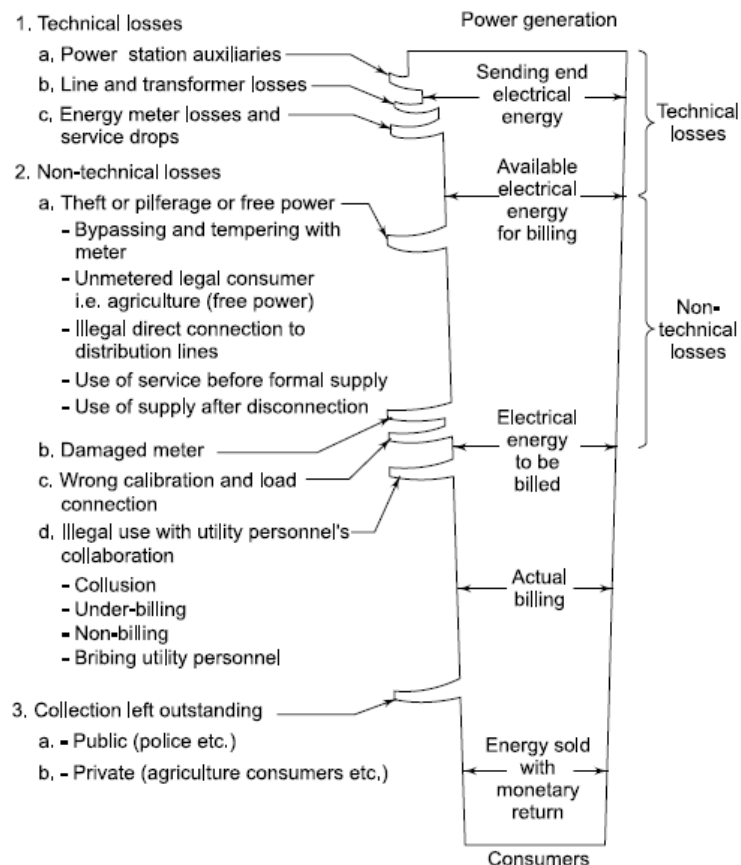


Figure 2-13: Sources of energy losses in power system [20]

2.5.1 No-load losses

The no-load losses occur in a system even when no load is connected. In the case of the transformers, the no-load losses are independent of the load, as they are attributable to the transformer excitation current. Thus, during an open circuit condition, applying the full supply voltage on the primary windings of the transformer, the current that flows in the circuit is excitation current and not load current.

Equation 2-16 presents the measure of system efficiency (being the useful power output divided by the total electrical power supplied), considering the dissipated power (P_d) throughout the system.

$$\eta = \frac{P_{out}}{P_{in}} = 1 - \frac{P_{dissipation}}{P_{out}} \quad (2-16)$$

2.5.2 Load losses

Load losses occur when current flows from the network into the loads, thus generating heat that emanates from the current drawn by the various loads connected to the system. In the case of the transmission lines for example, the line losses are a result of the square of current to the resistance (i^2R) of the transmission medium (the conductor).

Interventions at the design stage or in the operation stage can reduce the load losses as follows:

- Use higher system voltage;
- Do phase balancing of the electrical circuits;
- Reduce the loads, and
- Implement reactive power compensation.

2.5.3 Regulation losses

The regulation losses are attributable to reactive power-driven losses. For technical and financial reasons, improvement in the losses is achievable using one of the following techniques:

- Optimising the overhead line capacity;
- Optimising the transformer capacity, location, and use, and
- Opting for a higher voltage distribution system, based on the outcome of the cost and benefit exercise.

2.6 Active power and frequency control / Load frequency control

The basic function of the load frequency control (*LFC*) is to sense the change in frequency and maintain frequency of the electrical system within defined limits during steady state and fault conditions. Frequency is a measure of the balance between the active power generation and the active load power. In the case of the Lesotho power system, the load frequency control serves to hold frequency constant ($\Delta f = 0$) despite load changes during both normal operating conditions and island operation, subject to successful load-reduction.

Figure 2-14 depicts a schematic diagram for the mechanical hydraulic governor that achieves speed sensing, permanent droop feedback as well as computing functions for the systematic operation of mechanical components [1].

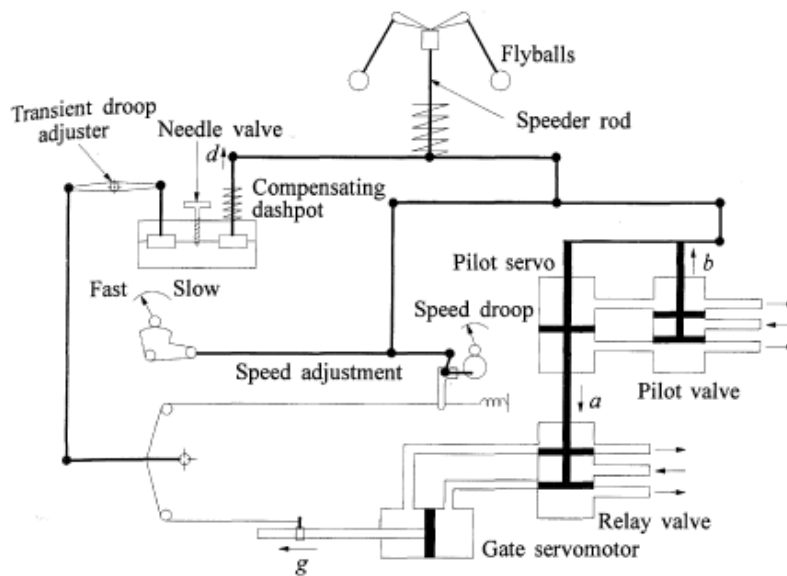


Figure 2-14: Schematic diagram of a mechanical hydraulic governor for hydro turbines [1]

In a power system, the load changes all the time, however, unless a load change is large enough to require governor action, the changes as required by the load variations come from the stored energy in the rotating masses [1]. In the event of a large load change and when the machines are under frequency control, they will correct the mismatch in the power change.

Each machine's contribution to the system depends on the droop characteristics or its regulation until activation of the load frequency control occurs. The well controlled machines maintain frequency of the system. The amount of change in the gate servomotor position depends on permanent droop, in which the position is a function of unit speed. Thus, the speed droop is characterised as a change in the unit speed measured against the governor output.

In the case of adjusting the load to zero, the generators would have negligible load to share, each unit would strive to provide the load power while driving other units into motoring mode. During disturbed system conditions, shortly after the occurrence of the fault, the governor systems acting under primary control mode increase or decrease the turbine power to adjust the frequency to be close to the nominal value. Under these conditions, the change in the generator power is then proportional to the deviation and split among the generating units according to their respective primary controllers' gains.

The load frequency control consists of four controls, viz:

- Primary frequency control

- Secondary frequency control
- Tertiary control, and
- Time control

2.6.1 Primary frequency control

This control technique activates the governor shortly after a disturbance, in so doing; the local feedback controllers sense the system frequency and act by opening the valves of the generator turbine. Following a perturbation, the governor system for the machines contributing in the primary control will increase or decrease their turbine power and, in doing so, attempt to drive the frequency close to the nominal value [7]. The change in the generation power and the remedy thereof is proportional to deviation in frequency split among the participating machines in the ratio of their respective gain(s).

To avoid the energizing of the primary control erroneously, the frequency deviation limit should be within the confines of ± 200 mHz [4]. This limitation also provides an advantage of reduced wear and tear on the part of the governor as a result of frequent starts.

Automatic load-shedding starts when the frequency drops to below 49.0 Hz, hence the limit for instantaneous frequency deviation is set to 49.2 Hz. To curb the system from transiting into overfrequency instability, the limit for maximum dynamic frequency is 50.5 Hz during steady-state condition. The key determinants in this control mode are inertia and governor response.

2.6.1.1 Inertia

This refers to the rotational mass that stores kinetic energy in proportion to its moment of inertia and the square of velocity. The new technology trends in power system design gave rise to systems operating at lower stability margins [6]. Notwithstanding new developments, the swing equation still governs the motion of the machine rotor with respect to the inertia torque to the resultant of the mechanical and electrical torque on the rotor (see equation 2-17)

$$J\theta = T_a \times N \times M \quad (2-17)$$

Where

J is the moment of inertia in kg for the rotating mass

T_a is the accelerating torque in newton meters (Nm) acting on the shaft, and

θ is the mechanical angle of the shaft in radians with respect to a fixed reference.

In the case of the Lesotho power system, in the event of the sudden loss of a tie-line causing the imbalance in supply/demand, the natural physical behaviour of the rotating machines is to tug on the mechanical kinetic energy, since the machines use kinetic energy to reinstate the equilibrium between generation and load. In tugging, the kinetic energy of the synchronous machines results into a slowdown in rotation and subsequently drop in frequency

2.6.1.2 Governor

Advanced technologies are enabling governors to provide fast distinct power frequency control to aid live loads, this compliments the slow, continuous governor response provided by the synchronous machines. While the governor maybe slow against the fast load dynamics, it functions to arrest frequency decline or oppose frequency variations that are beyond the nominal limits. To avoid activating the governor action for unperturbed condition when the system is operating near the nominal frequency value, the deviation limits are set and the governor operation activates based on the set droop value [7].

Equation 2-18 calculates the relationship between the governor shaft speed and mechanical power input

$$\tau_j \omega = P_m - P_e = P_a \text{ pu} \quad (2-18)$$

Where

τ_j is the time constant

ω is angular speed in radians

P_m is mechanical power, and

P_e is electrical power

2.6.2 Secondary control

When a system imbalance leads to over- or underfrequency of each generator unit the primary control will adjust to increase or decrease the active power generation. The secondary control relieves the primary control after the primary control has brought the system frequency close to the permissible limits of steady state operation 15 minutes after the incident. Its function is to maintain the equilibrium between generation and demand within each control area. The

use of secondary control therefore finalises the control of frequency to a nominal value to re-establish the cost-effective generation delivered by each unit.

For rapid reaction time within each control area, the area control error (ACE) is limited to zero continuously. The computations for the ACE are summarised as the sum of the power control error and the frequency control error and presented in equation 2-19 [21].

$$ACE = \sum_j^n (P_{ij} + K_i * \Delta\omega) \quad (2-19)$$

Where

ACE is control area error;

ΔP_{ij} is change in active power;

K_i is a determinant for interaction with the neighbouring grids, and

$\Delta\omega$ is the change in frequency.

During examination of active power control using the secondary control option, participating factors for individual machines account for regulation of frequency deviation.

2.6.3 Tertiary control

The tertiary control picks up from the secondary control after the 15 minutes elapsed. It is activated manually or automatically to have more secondary reserve available based on readily connectable units within 15 minutes request to expand the bandwidth of secondary control. The operation of tertiary control is by design slower than both the primary and secondary control [7] [10].

2.6.4 Time control

The synchronous machines use the time control to globally match all the connected synchronous machines' pre-selected settings to share the system load as the system transits into stable operating condition [7].

2.7 Reactive power and voltage control

The voltage regulator varies the rotor current automatically to maintain the terminal voltage of the synchronous machine even when load changes occur. The sources of reactive power are generators, capacitors, reactors and static var systems (SVC) to balance the supply and demand of the reactive power in the system.

The excitation system controls the reactive power of the generators [21]. To maintain the voltage levels within the permissible limits in the power system, the other support platform utilised is transformers through an automatic tap changer operation to regulate terminal voltage. The generation system is summarized as consisting of prime-mover, excitation, and torque control (see section 2.3 Generator excitation system).

A load-flow study is a pre-requisite for the assessment of system voltage stability, and a plot of resulting changes for analysis aids in analysing the voltage profile against the increase in loading at the selected bus (see Figure 2-15). The operating points “A, B and C” assume a uniform power factor to examine to voltage stability.

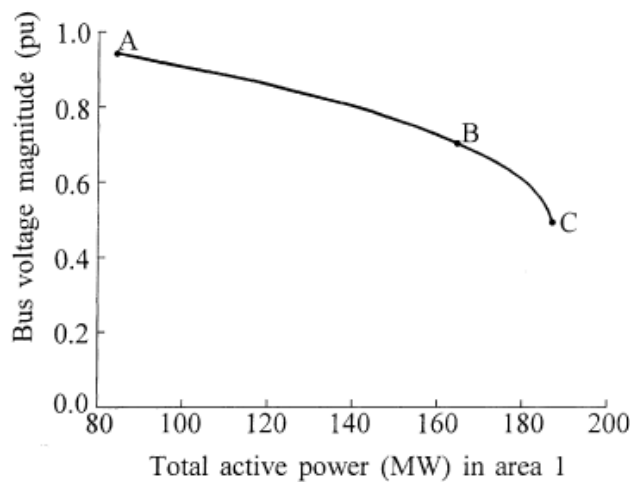


Figure 2-15: Illustration of V-P relationship for a selected bus in a system [1]

The radial system architecture connects selected buses. At operating point “A”, convergence of load flow solution achieves voltage stability. At the operating point “B”, where the load is just above 160 MW, the voltage profile exhibits an operating condition near the critical point. At operating point “C”, a further increase in active power loading will result in a load-flow solution non-convergence, hence a critical condition and therefore voltage will collapse [1]. Section 2.7.1. further explains the indications of reactive power and voltage control (Q-V characteristics of the system) for stable and unstable operation.

2.7.1 Q-V characteristics of the power system

When injecting reactive power into the system, the expectation is that the voltage profile will show positive reaction to the action. The highlighted area indicates a condition where an injection of reactive power results in a decrease in bus voltage towards a zero gradient, therefore, this indicates an unstable voltage operating region on the graph (see Figure 2-16). Increasing reactive power beyond the zero gradient, the voltage profile responds positively, indicating a stable voltage-operating region, hence a stable system voltage. The analogy

assumes that the reaction of voltage on the selected “bus 200” is uniform with the rest of the system to meet the qualifications for a stable voltage condition with reference to operating point “A” on Figure 2-15.

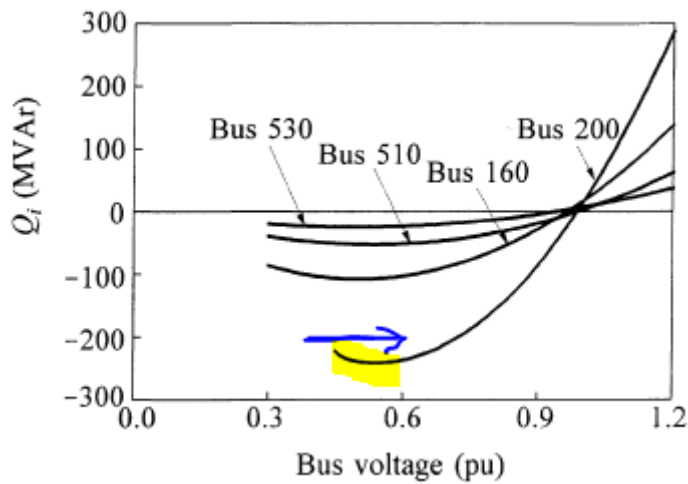


Figure 2-16: Illustration of Q-V characteristics in relation to voltage stability [1]

In the case of operating point “C” with reference to Figure 2-15, a further increase in active power results in a voltage collapse. The corresponding reaction on the Q-V characteristic indicates that the voltage profiles shift with relation to the injected reactive power for different loading conditions, in this case being 186 MW load and 117.9 Mvar injection at bus 200 (see Figure 2-17). The rest of the voltage profiles at the other busbars have shifted significantly as the load increases with increase in reactive power injection [1]. The conclusion is that the Q-V sensitivity depends on the loading condition in a system.

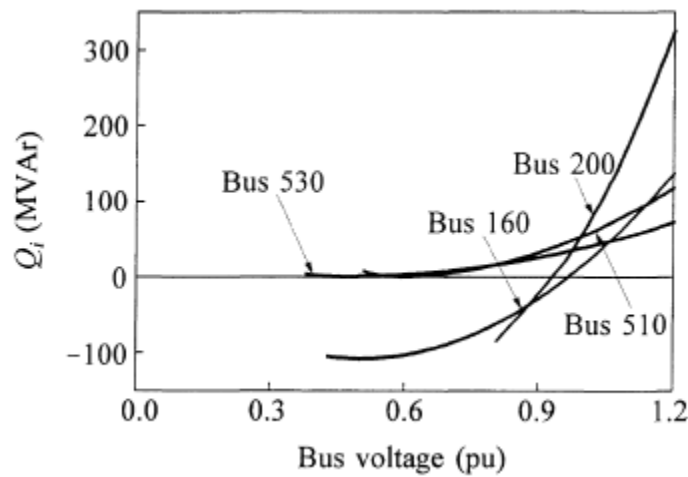


Figure 2-17: Illustration of Q-V curves at critical operating conditions [1]

2.7.2 Reactive power control

In a power network, the reactive power is essential for voltage control to limit the voltage variation to within the permissible limits of $\pm 5\%$ [2] at the customer point of connection. At the transmission level, reactive power is required to maintain voltage to aid in the delivery of active power through the transmission system. On the other hand, reactive power consumes the transmission and generation resources and thus it is essential to optimise it. While this is so, the reactive power need for the voltage-support requirement is a function of the locations, the magnitude of generator outputs, customer loads as well as the system configuration [17].

At low system load levels, the transmission lines act as capacitors and increase terminal voltages, a phenomenon known as the Ferranti effect. At the industrial level, motor loads and other loads need reactive power to achieve useful work conversion. The lack of adequate reactive power in the system results into voltage sagging, which compromises the amount of power transmitted through the line. Comparable reactive power sources such as SVCs and reactive power capacitors etc. are some of the contingencies used to respond quickly to changing reactive power demands to maintain acceptable voltage throughout the system.

In a generating station, the synchronous generators are loaded such that there will be reserves for reactive power to control voltages at specific nodes in the system and/or to control the exchange of reactive power with the neighbouring grids. The automatic station controller combines the sources of reactive power to control voltages at the specified buses in the system. Where the reactive power generated by the synchronous machines is not enough due to limitations, other forms of reactive power compensation such as static var compensators, shunt condensers, and synchronous compensators are used.

An increase in reactive power injection to one bus that results into an increase in voltages in all buses, fulfils the voltage stability condition. In the case of utilising the generators for reactive power injection, the use of the excitation system aids to achieve this objective. A determinant for the required amount of reactive power for compensation is the load terminal voltage, for which a drop-in voltage warrants an increase in reactive power support.

To achieve this control, a reference for monitoring the voltage level is set. Deviations that are more than the pre-set values become amplified and signalled for increase in the field excitation current, the increase in excitation current thus results in the increased terminal voltage.

2.7.3 Voltage control

The voltage control, for regulation purposes, maintains voltage in all the system buses within permissible limits; this is a requirement in power system to guarantee proper operational conditions on the equipment. The benefit of voltage control is improvement of the system reaction under dynamic conditions such as load rejection, line switching and system faults where reactive power is required quickly to maintain system voltage stability [22]. Thus, voltage control guides reactive power flow and vice versa. To achieve this, some of the techniques used are:

- Installation of fixed switched shunt capacitors,
- Static var compensators,
- On-load tap changing transformers,
- STATCOMs;
- Synchronous condensers, phase shifting transformers etc.,

2.7.3.1 HV capacitors

The use of shunt capacitors entails injecting a reactive power equivalent to the deficit, which in turn improves the power factor as well as the system stability. The capacitors can either be of a fixed type or adjustable by means of switching devices to adjust the network operation flexibility. This technique has an advantage of low capital cost, as it is ready for installation at various nodes in a system. However, they have a drawback that the reactive power output is proportional to the square of voltage. At low voltage, where the compensation is most needed, the voltage improvement is small because of the reduced reactive power output of the capacitor bank [23].

2.7.3.2 Shunt reactors

Load varies from time to time in the power system; in some cases, the load on the system is low. Under low load conditions, the voltage tends to rise, particularly on long

transmission lines; the rise may be so high that it is beyond the permissible limits due to the line capacitance [1]. The installation of shunt reactors on a high voltage system or on a transformer's tertiary windings aids voltage regulation (see Figure 2-18).

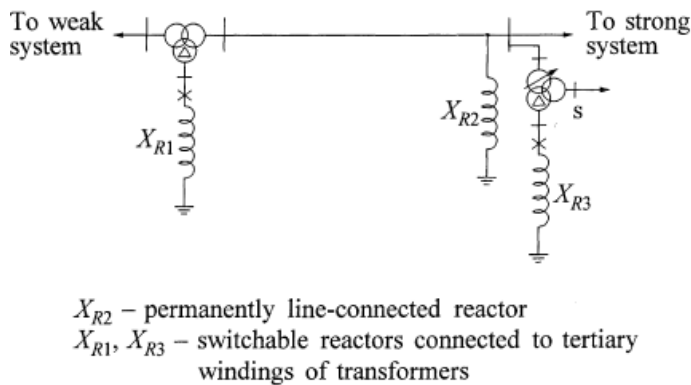


Figure 2-18: Illustration of line and transformer connected reactors [1]

2.7.3.3 Static var compensation systems

The static var compensation (SVC) systems use thyristors for control of the reactive power [24]. This system absorbs reactive power under low load conditions, and supplies reactive power under heavy load conditions (see Figure 2-19). Adjusting the firing angle of the thyristors to match the system reactive power requirements controls the amount of reactive power flow. Regulating the firing angle controls reactive power flow and reduces voltage fluctuations and improves the line capacity under heavy load conditions [16].

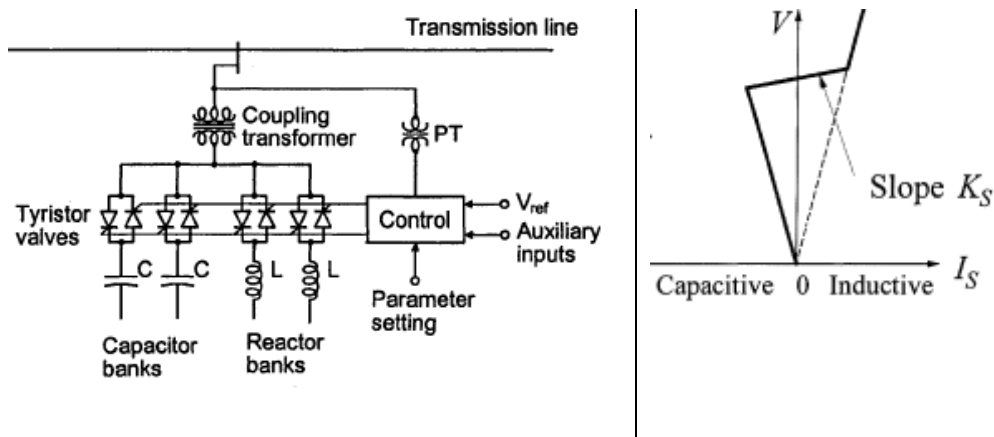


Figure 2-19: An illustration of idealised static Var compensator connection [25]

The principal advantage of this system is flexibility, continuous reactive power compensation that operates in both the capacitive region and the inductive region.

2.7.3.4 Static compensator (STATCOM)

The STATCOM controls the flow of reactive power in a similar manner to the SVC; the difference is that STATCOM exploits voltage source converters [10]. Figure 2-20 depicts a STATCOM schematic diagram based on the voltage converter as well as on characteristics for current, voltage and power when in operation. This mode of operation injects non-sinusoidal corrective current that serves to regulate load voltages, compensate for reactive power demand, control the load power factor and as a result improve power quality.

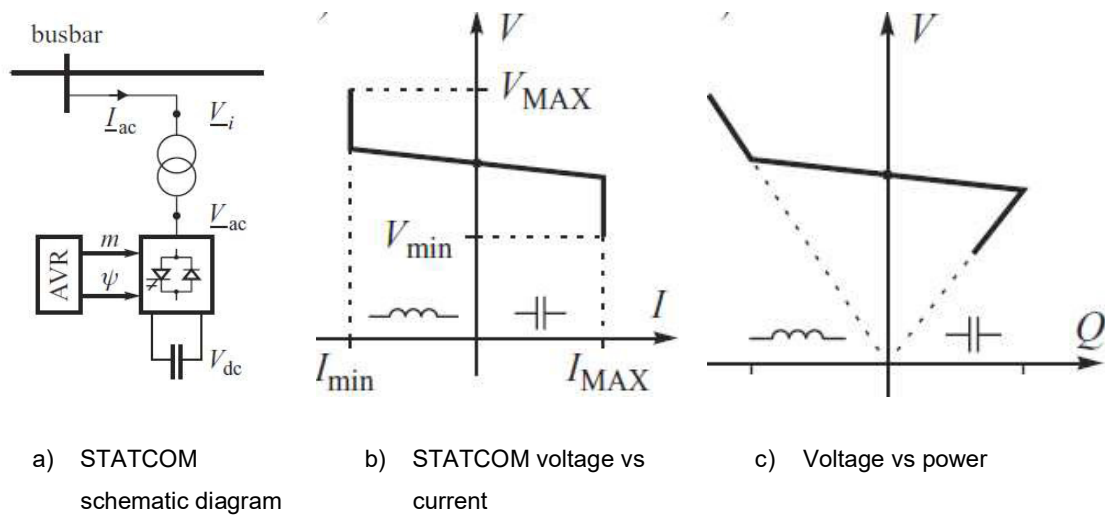


Figure 2-20: Typical STATCOM based on voltage converter and its characteristics for current vs voltage and power vs voltage [10]

2.7.3.5 Step voltage regulation

In a system in which the transformers have an on-load tap changer (see Figure 2-21), the regulation of voltage magnitude between the primary side and the secondary side varies with the transformer tap position. The tap changers are motorised and vary the ratio of the transformer; they operate automatically to maintain voltage within set limits. Thus, adjusting the tap changers controls the terminal voltage.

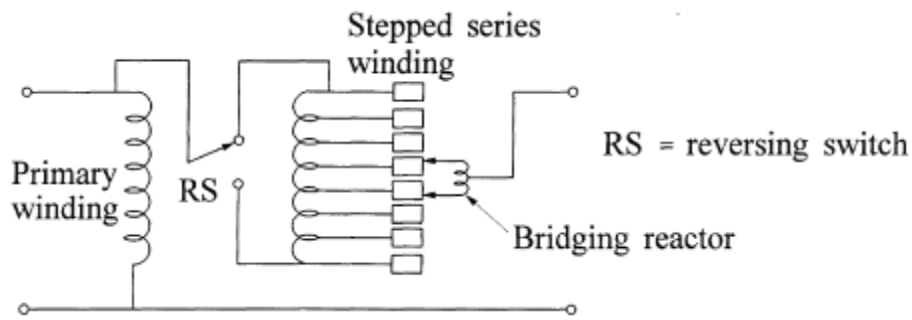


Figure 2-21: Illustration of step voltage regulator [1]

The advantages of this technique are:

- Constant flux density, hence constant tertiary voltages over tapping range, and
- Achievement of a cost-effective advantage through change in the turns ratio.

However, the drawbacks are:

- High capital cost, and
- High impedance deviations due to the varying impedance on the windings over the tapping range resulting from variations in tap positions.

2.7.4 Voltage stability

The definition of voltage stability is concerned with the ability of the system to regain a steady-state condition with voltages at all the busbars within the acceptable limits following a system perturbation [1]. During perturbations, a power system transits into voltage instability when an increase in demand or change in system conditions causes voltages in any of the busbars to progressively divert from the allowable limits [1]. The system is unstable if at least injecting reactive power in the same bus results in a voltage magnitude decrease. The common factors that cause the system to transit into voltage instability are:

- Excessive real power demand that results in a high voltage drop within the system, and
- A lack of reactive power support.

A sensitivity analysis, two-port system, modal analysis and impedance transfer explain the effect of a sensitivity analysis in power systems. These analyses cover the extent of impact in effecting changes in the system reactive power.

2.7.4.1 Sensitivity analysis

Performing static voltage stability calculations establishes voltage stability of the system. Linearizing the load-flow equation around an operating point as demonstrated in equation 2-20 aids the performance of a sensitivity analysis [12].

$$\begin{bmatrix} J_{P\vartheta} & J_{PQ} \\ J_{Q\vartheta} & J_{QQ} \end{bmatrix} \begin{bmatrix} \partial\vartheta \\ \partial Q \end{bmatrix} = \begin{bmatrix} \partial P \\ \partial Q \end{bmatrix} \quad (2-20)$$

In equation 2-20 the Jacobian matrix [12] is used to compute the change in the voltage magnitude and angle due to small changes in the active power and reactive power. Where the change in power (ΔP) is equated to zero, the dV/dQ are computed according to equation 2-21.

$$\partial v = J_{Qv}^{-1} \partial Q = S_{vQ} \partial Q \quad (2-21)$$

Where

$$J_{Qv} = -J_{Q0} J_{P0}^{-1} J_{Pv} + J_{Qv} \quad (2-22)$$

Equations 2-21 and 2-22 formulate voltage magnitude at various busbars by a linear combination of reactive power deviations as per equation 2-23.

$$\partial v_i = S_{i1} \partial Q_1 + \dots + S_{in} \partial Q_n \quad (2-23)$$

From equations 2-20 to 2-23, voltage stability is dependent on the relationship between P, Q and V. The indication of stable operation is a positive dV/dQ , in which high sensitivity indicates a small deviation in reactive power, causing significant changes in the voltage magnitude [12]. To achieve a more stable system, a lower sensitivity is desirable, thus, high sensitivity is a characteristic of a weak area in a system.

In the case of the transmission line for an example, voltage drop depends on the active power and reactive power transfer, thus, failure to fulfil reactive power demands subsequently results in the existence of a voltage instability condition.

For the system to transit into instability, events occur that result in a non-compliant voltage profile in other parts of the system. A two-port system illustrates the relationship between the sending and receiving end voltages; the illustration extends to the discussion of the contribution of impedance in the power transfer.

2.7.4.2 Two-port system

In a two-port system depicted in Figure 2-22, the magnitude of the receiving end voltage is expressed mathematically in equation 2-24 as a product of the line impedance and the current flow in the system.

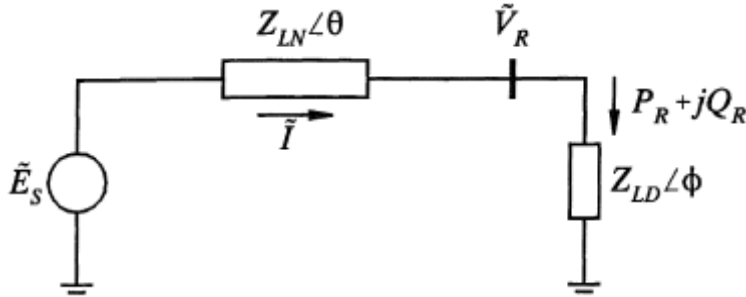


Figure 2-22: A typical two-port system to exemplify voltage stability occurrence [1]

$$V_R = Z_{LD} I = \frac{1}{\sqrt{F}} \times \frac{Z_{LD}}{Z_{LN}} \times E_S \quad (2-24)$$

Where

V_R is the receiving end voltage

Z_{LD} is the load impedance

I is the current flow in the circuit

Z_{LN} is the line impedance, and

E_S is the voltage source

$$F = 1 + \left(\frac{Z_{LD}}{Z_{LN}} \right)^2 + 2 \times \left(\frac{Z_{LD}}{Z_{LN}} \right) \cos(\theta - \phi) \quad (2-25)$$

When applying source voltage to the system, equation 2-26 calculates power consumed by the load. For instance, an increase in load demand, Z_{LD} , P_R increases rapidly at the first instance and slows down beyond the maximum point (see Figure 2-23). The crux of the matter is that when the active power transfer reaches a maximum value at the peak of the voltage rise, any further attempts to increase beyond this critical value results in an unstable voltage condition.

$$P_R = V_R \times I \cos \phi = \frac{Z_{LD}}{F} \times \left(\frac{E_S}{Z_{LN}} \right)^2 \cos \phi \quad (2-26)$$

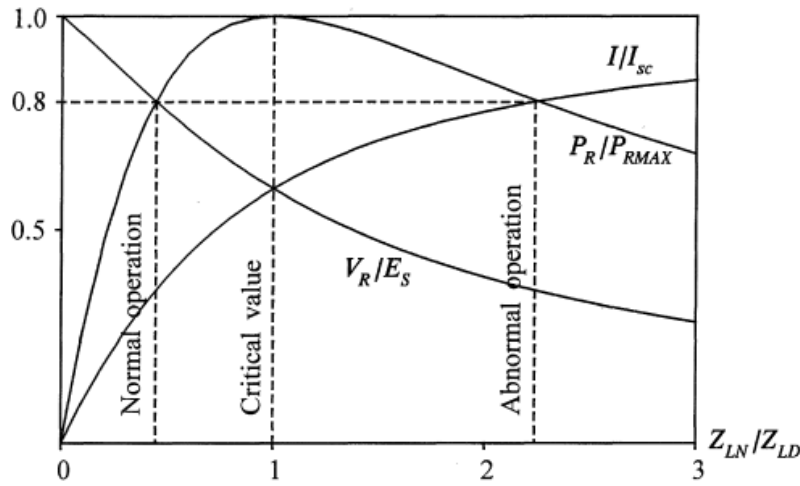


Figure 2-23: Relationship between receiving end voltage, current and power [1]

The system reaches maximum power transfer when the source voltage is equal to the receiving end voltage, a point at which the ratio of line-to-load impedance is unity ($(Z_{LD}/Z_{LN}) = 1$) represents a satisfactory system.

2.7.4.3 Contribution of impedance in power transfer

The influence of line impedance on the power transfer is that the system impedance is indirectly proportional to the power transferred between the two points at any given time. That is, the line impedance contributes to the decrease in the terminal voltage in the form of a voltage drop, which is also a determining factor for the maximum transfer capacity of active and reactive power. Voltage stability thus depends largely on the close relationship between active power, reactive power, and voltage (see Figure 2-24), where the load power factor is crucial for the power-voltage relationship in a system.

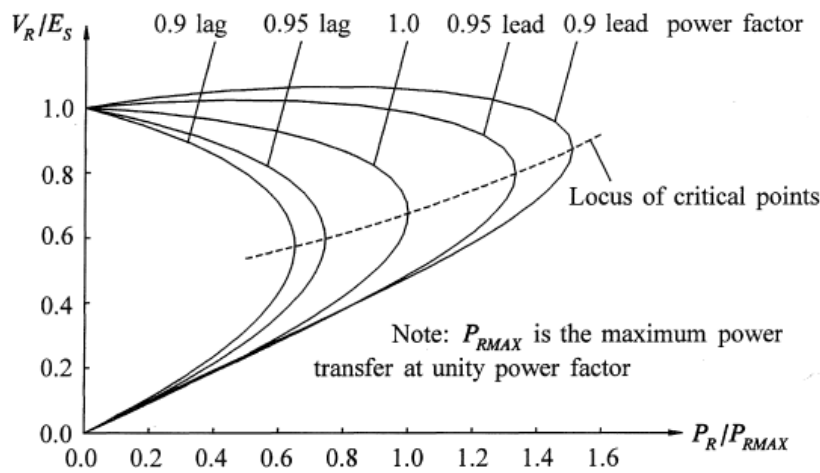


Figure 2-24: System behaviour under different load-power factor [1]

During a load-flow study, the characteristics of the loads determine the various factors affecting the voltage stability, such as control of the transformer tap ratio, generator voltage control and its limits, as they are crucial to voltage control.

In stability studies, the design of synchronous machines dynamic controls, compensators, transformers etc., aims at interacting in a manner that avoids a voltage collapse condition (see Figure 2-25).

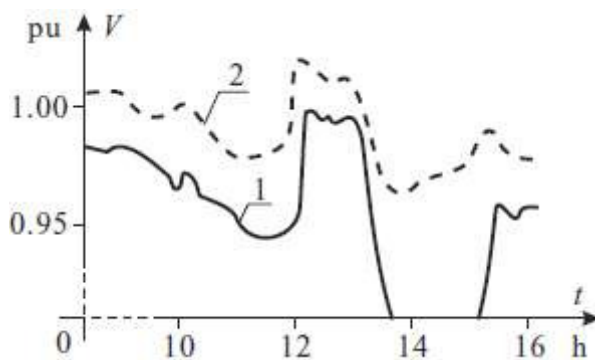


Figure 2-25: An illustration of voltage collapse [10]

In the case of the Lesotho power system during the tie-line failure, the synchronous generators become heavily stressed and transit into unstable operating regions, and subsequently system collapses. The voltage collapse occurs in the form of a drop in voltage below the permissible limits and it continues to drop to a level at which fast reactive power support is absent. The major factors contributing to voltage collapse are:

- Weak transmission network in which the impedance of the system is high;
- Synchronous generators operated outside the capability curves during the tie-line failure;
- Lack of reactive power compensation in the system, and

- Loading condition.

In a heavily loaded system, the system becomes vulnerable in a sense that when perturbations occur, the ability of the system to function and retain a steady-state condition is dependent on the strength of the system's low system impedance [1].

2.7.4.4 Modal analysis

For the study of the oscillatory stability, the computations of eigenvalues and eigenvectors are key in establishing the state of natural system oscillation modes. The oscillation modes are present in the conditions in which all the plant controllers are deactivated in which case the synchronous machines are each running under constant power, after which the controllers are activated to investigate the effect of the controllers in addition to the system [12] [1]. The methods applied for analysis are the QR/QZ-method and selective modal analysis that is known as the Anoldi/ Lanczos method, which is suitable for large power systems [12].

In a multi-machine condition, the system is stable if all the conjugate complex eigenvalues making up the rotor oscillations result into negative real parts. Thus, the system is stable when the real parts of the oscillations for each generator lie in the left complex half-plane [1] (see equation 2-27).

$$\lambda = \sigma_i \mp j\omega_i \quad (2-27)$$

The oscillatory mode will be stable if the real part is negative (see equation 2-28).

$$\sigma_i < 0 \quad (2-28)$$

The damping ratio ζ determines the rate of amplitude oscillation decay (see equation 2-29).

$$\zeta = \frac{-\sigma}{\sqrt{(\sigma^2 + \omega^2)}} \quad (2-29)$$

Where

σ_i is the real part of the eigenvalue, and

$j\omega_i$ is the imaginary part of the eigenvalue

2.7.5 Prevention of voltage collapse

Without a robust form of reactive power support in the Lesotho power system, the system inadvertently collapses when voltage violations occur during the loss of a tie-line. Under this condition, as the reactive power increases, voltage magnitude decreases until it reaches a low value; here referred to as a voltage collapse.

2.8 Underfrequency load-shedding

Nowadays, the implementation of the underfrequency load-shedding (UFLS) technique uses microprocessor-based multifunction relays to shed pre-identified blocks of loads, using different time delay settings and the underfrequency thresholds to trigger the dropping of different blocks during different load-shedding stages [3]. To detect the power imbalance through monitoring the frequency gradient, a well-designed UFLS scheme trips enough loads to maintain the power balance in the system. During dynamic conditions, between the occurrence of a perturbation and the dynamics result thereof, the system transits from the transient state to the steady-state condition. Figure 2-26 shows the summary of information and the flow-chart that shows the requisite procedures in power system stability studies including the UFLS.

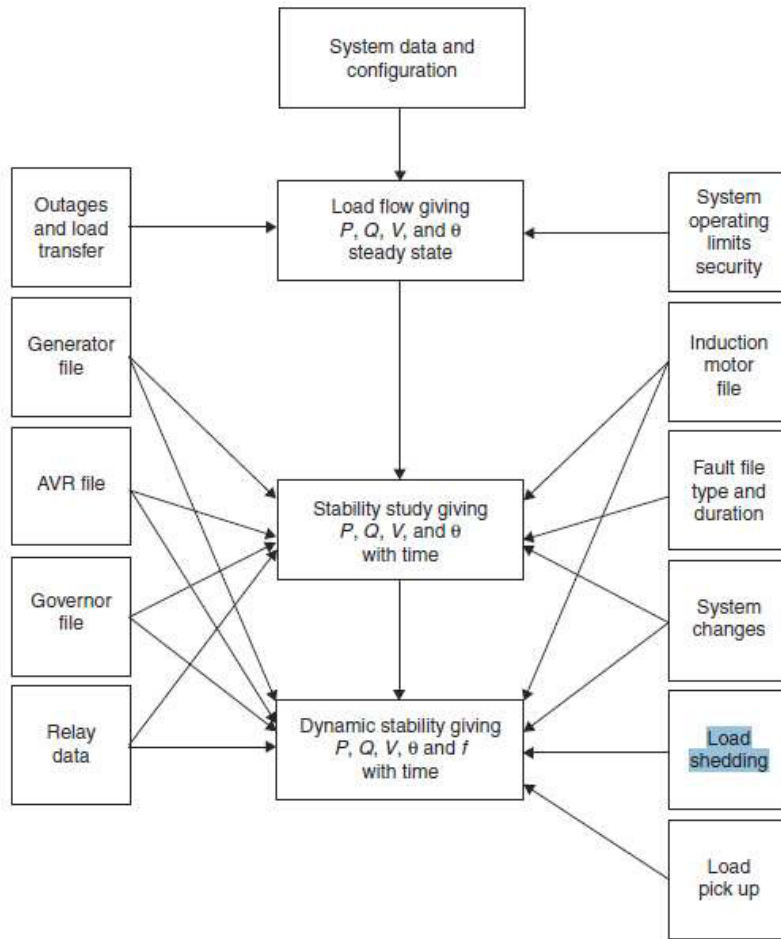


Figure 2-26: Flow chart showing the procedure in power system stability studies including load-shedding [13]

In the case of frequency violations, the underfrequency relay computes and compares the supply frequency against the pre-set system frequency and operates after a defined time delay. The delay allowed is to avoid mal-operations resulting from transient events in the system. In performing the computations (see equation 2-30) [13], the main interest is to achieve a supply/demand balance post execution of load-shedding.

$$f_t = f_o \sqrt{\frac{(e^{\frac{tL}{H} \times (L-G)} - G)}{L}} \quad (2-30)$$

Where

H is total system inertia (MJ)

L is system load (MW)

G is system generator output (MW)

f_o is initial frequency (Hz)

t is time in seconds following perturbation, and

f_t is frequency during the dynamic condition following load-demand change

To prevent system collapse in the Lesotho power system, following a perturbation, the operation of the underfrequency relay should drop even sensitive loads to prevent the collapse condition in the system.

In the application of load-shedding, the amount of load shed should be above the theoretical minimum load to curb the occurrence of the cascading effect. Cascading can be due to non-successful prior load-shedding stages, whilst striving to maintain power system stability. During the system perturbations, which result in frequency violations, the computation time delay for dropping blocks of loads considers the circuit breaker operating time, generator inertia and governor response before initiating the succeeding load-shedding stage. Load-shedding takes place in the following forms:

- Static load-shedding
- Dynamic load-shedding
- Adaptive load-shedding

2.8.1 Static load-shedding

This technique effects load-shedding by tripping the feeder breakers thus dropping blocks of loads in different shedding steps to achieve generation/consumption balance. At the start of a generation/load (power) imbalance, the frequency gradient changes and when this change reaches a level adequate to trigger load-shedding, dropping loads in different blocks starts on the least priority loads. It is only on failure to achieve equilibrium that the second priority of loads is shed [26].

In the case of the Lesotho power network, the stage 1 operation operates to arrest the deficit created when a tie-line fails. While relay manufacturers provide set points of 0.01 Hz for underfrequency relays, the practical considerations have shown that separation between steps should not occur in less than 0.1 Hz increments [14]. While this is so, the system average tripping time including the breaker operations should be no more than 14 cycles and the system frequency arrest should be activate before frequency decline drops to below 49.0 Hz for stage 1 load-shedding.

The drawback for this technique is the amount of the load behind the assigned breaker to open. It has another drawback of not being able to distinguish the amount of load assigned to feeders of different priorities. These factors make it less usable in today's environment as compared to other techniques, as the amount of load due for disconnection is unknown.

2.8.2 Rate-of-change of frequency load-shedding

This system uses the rate-of change-of-frequency (ROCOF) method as an indicator for power imbalance for enabling fast load-shedding operations to speed-up the operating time for both over- and underfrequency conditions. During the system overload, ROCOF is directly proportional to the amount of system overload [3]. The cause for change in frequency is the difference between the mechanical power input and the comparable electrical load. For application on protection relays, it is crucial to know the frequency delay at diverse amounts of overload.

An estimation of the rate of change is achieved through the application of equation 2-31 following disconnection from the grid, thus transiting into island operation.

$$\frac{df}{dt} = \frac{\Delta P \times f}{2 \times G \times H} \quad (2-31)$$

Where

ΔP is change in power output between synchronised and island operated system

f is rated system frequency

H is inertia constant, and

G is the machine rating in MVA

The rate of change in frequency also affects the voltage change on frequency load-shedding. In the situation where the generating units are overloaded (during island operation), the overload results in a decrease in system voltage, accordingly, it affects the magnitude of both active and reactive power.

Equations 2-32 and 2-33 present a mathematical model of the degree of impact on real and reactive power.

$$P_1 = P_{10} \times \left(\frac{V}{V_n}\right)^p \times \left(\frac{f}{f_n}\right)^p \times f \quad (2-32)$$

$$Q_1 = Q_{10} \times \left(\frac{V}{V_n}\right)^p \times \left(\frac{f}{f_n}\right)^p \times f \quad (2-33)$$

Where

P_1 is a real power

Q_1 is reactive power of the system

P_{10} is active power before the perturbation

Q_{10} is reactive power after the perturbations

V_n is the nominal voltage

f_n is the system frequency, and

V is the measured bus voltage

p_v, p_f, q_v, q_f are the parameters for calculating the autonomy of the active and reactive power with voltage and frequency.

In the case of Lesotho power system, the main application could be the loss of the Eskom tie-line, thus leading in island operation. During island, the ROCOF technique can be applied when one of the three generating units fail. In these applications, UFLS can be trigger based on the ROCOF technique, sometimes referred to as df/dt method [27]. The amount of load earmarked for shedding is dependent on estimations derived from ROCOF, which is an event dependent operation. In this way, the risk of reducing more load than necessary minimises the risk of frequency overshoot during UFLS. The advantages that come with this technique include enabling triggering of the automatic UFLS scheme at a much higher frequency value.

2.8.3 Dynamic load-shedding

This technique operates on measurement and sheds a predefined percentage of the total power and not a pre-defined number of loads as in the static load-shedding technique. In the case of the Lesotho power system, the application of this technique would entail analysing the system behaviour through a simulation in which stage 1 of the operation would rely on the status of the tie-line breaker. The succeeding load-shedding stages would operate based on frequency decline and increase in the active power consumption seen by the generators resulting from the system overload condition.

The proposed operation procedure for the Lesotho power system includes the identification of the loads for shedding at each step through the selection of the optimum combination of feeders. Figure 2-27 shows an example of the proposed solution that trips the feeders in four steps, in which each step has a pre-defined load shed according to the network loading condition. In this example, the decision to trip loads considers the technical and economic impact.

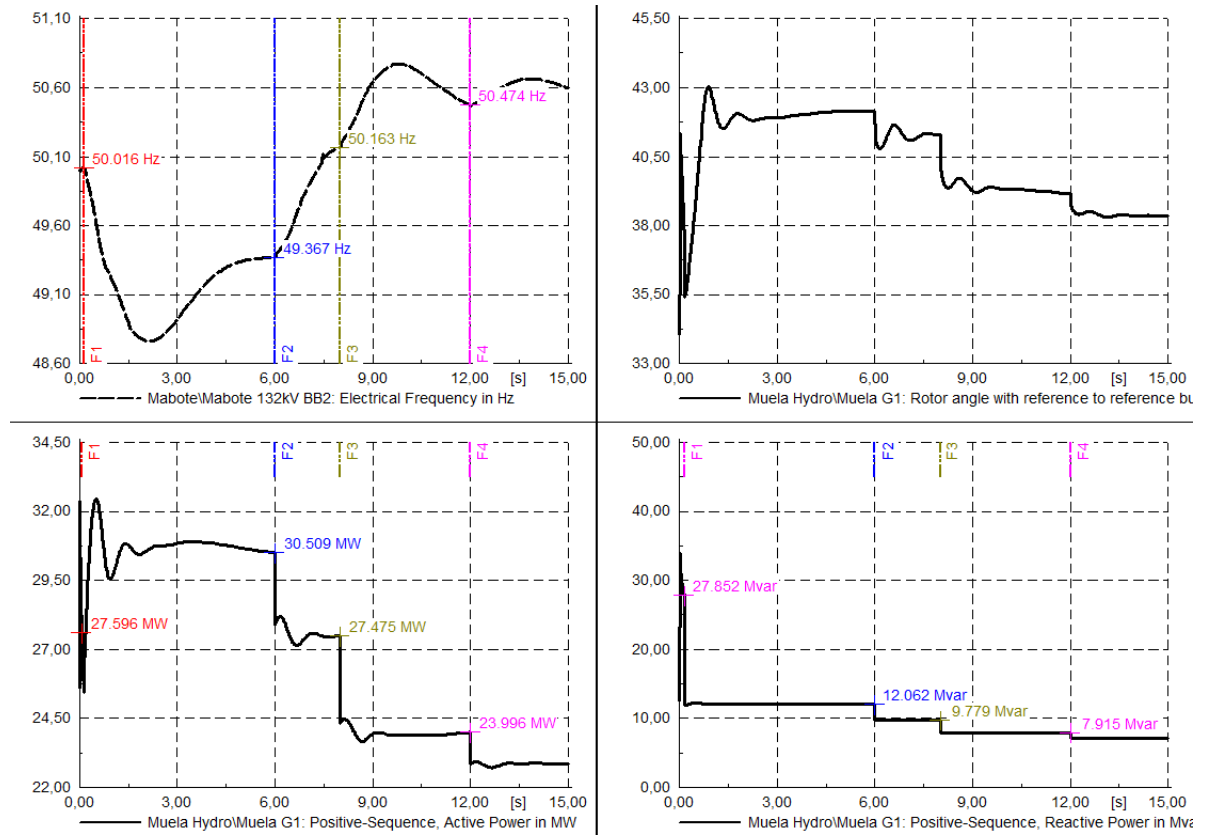


Figure 2-27: Illustration of the four steps operation in dynamic load-shedding technique

2.8.4 Adaptive load-shedding

The application of this technique for the Lesotho power system would entail it being operational when extreme overload in a system occurs, such as the tripping of a tie-line or the tripping of one of the generating units during island operation. In the case of the Lesotho power system, when connected to the grid, the extreme overloads refer to an estimate of 40% to 60% of the actual network load. When this condition occurs, it would initialise tripping of loads in order of their priorities. On receipt of the error feedback, indicating the imbalance, the process of computing of the trip signal command to trip the selected loads commences (see equation 2-34).

$$\sum P_{Shed} = \sum P_{Load} - \sum P_{Generator} \quad (2-34)$$

The computations are based on the active power measurements of the generator loads and incoming feeders, and are calculated from one phase current and a corresponding busbar voltage. This approach sheds a large amount of load for a massive imbalance in the network and less load for a small load inequity. The disturbances on the grid trigger load-shedding in island mode in which the load-shedding criteria are based on monitoring the frequency value.

The extent of monitoring covers changes in frequency over a period, the value of active power flows relative to the generation and external power supplied to the system.

When the system transits into island operation, during adaptive or dynamic load-shedding, load balance is achieved by implementation of either of the following:

- Fast load-shedding or
- Slow load-shedding.

2.8.4.1 Fast load-shedding

Whereas underfrequency load-shedding is response driven following the perturbations in the system, fast load-shedding (FLS) becomes active when pre-selected loads trip automatically [28]. FLS trips without waiting to get a signal on the monitored and activated frequency response and works purely on the activation of an event on the power system. Both techniques (UFLS and FLS) are still relevant in today's networks and therefore they should be coordinated to achieve system stability. FLS is applied in severe high probability events, while on the other hand UFLS is applied for less likely contingencies.

During the application of FLS, computation of the power balance takes place to establish the value of the spinning reserve. These computations are a measure of the criticality of events that technically warrant the activation of FLS; sudden change in the loading condition or failure of a tie-line in the power system. Equation 2-35 calculates the spinning reserve [29].

$$P_{spin} = (\sum_{x=1}^n (P_{capx} - P_{genx})) + (P_{maxGrid} - P_{grid}) \quad (2-35)$$

Where

P_{spin} is the spinning reserve

P_{capx} is the maximum active power capacity of the generator

P_{gen} is the active power produced by the generator at the moment of occurrence of the event

P_{Grid} is the active power imported or exported to the national grid, this value is zero when the system is operating in island mode, and

$P_{MaxGrid}$ is the maximum power possible to be exported or imported from the grid when the system is operating in island mode

For FLS to be effective, the value of the load to be shed following the signal of the critical/perilous event, computation of the amount of load is estimated mathematically (see equation 2-36) [29].

$$P_{ToBeShed} = P_{SpinGenTrip} + P_{GenTrip} - P_{spin} + Offset \quad (2-36)$$

2.8.4.2 Slow load-shedding

This technique monitors frequency driven events and activates operation when frequency drops to below the pre-determined UFLS scheme design values. In the event of frequency decay at a rate that is much faster than the pre-determined rate, slow load-shedding becomes active to reduce the system overload when the load violations at the generation station are detected. In the case of a multi-machine system, the loss of a generator is a trigger for the assessment of the power margins in which the return of the negative power margin computations triggers load-shedding of a load equivalent to the deficit in generation to maintain the power balance.

2.9 Recent events of blackouts around the globe

The occurrence of power blackout dates back quite a few years and includes the November 9, 1965 blackout that occurred in the North-Eastern part of the United States [30]. Blackouts occur even in first world countries like the USA and Canada, but to mention a few (see Figure 2-28) [31].

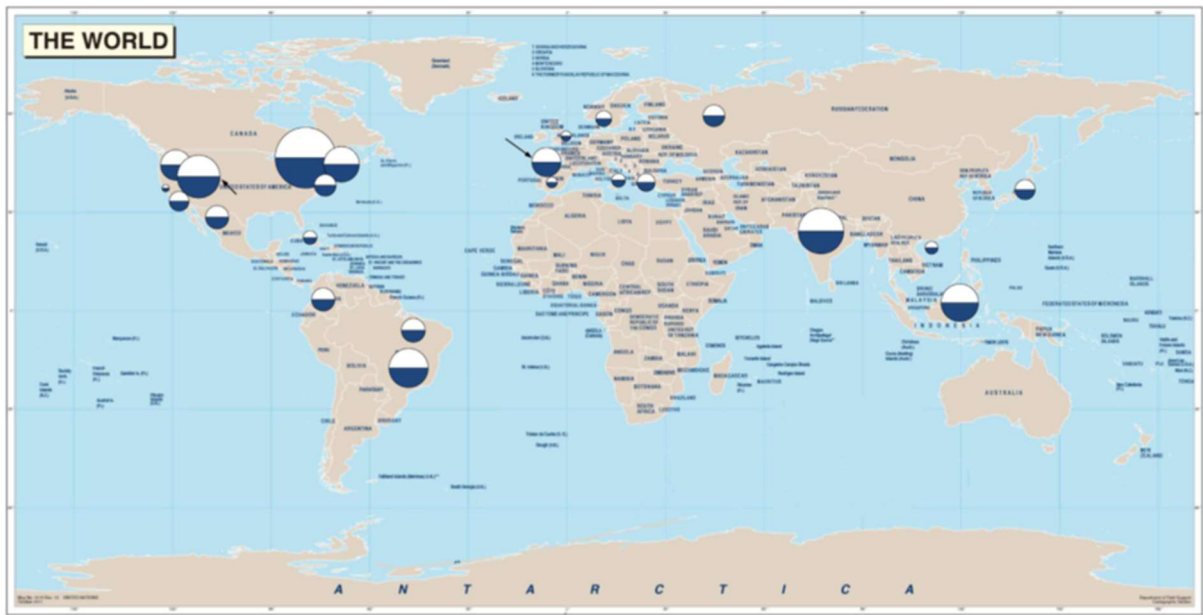


Figure 2-28: Incidents of blackouts around the globe, circular representation depicts severity of the incident [31]

Even though the blackout incidents globally have a large impact with techno-economic consequences, power systems continue to undergo huge changes including increased capacities, deregulation on the electricity industry and integration of renewable energy technologies into the grids. In consideration of these challenges, the absence of load management by way of load-shedding can result in a systems' collapse condition. The impact of blackouts is far reaching, with most of the services negatively affected such as traffic, communication, and essential services.

A brief discussion extends to the selected recent blackout events hereunder:

- The 2015 Turkey blackout
- India 2013 Blackout
- The 2003 Northeast blackout

2.9.1 Turkey 2015 Blackout

This blackout incident occurred in the Turkish system on 31st March 2015; was classified as the third in the Continental Europe system [32] and has a record count dating 15 years from the date of the incident. Even though the Turkish system interconnects with other systems, the effects of the blackout affected the Turkish system only. Prior to the occurrence of the incident, the network was stable; temperatures were high and the threat was the high corridor loading on the 400 kV lines. The system was not compliant with the N-1 criterion due to an outage on the 400 kV line connecting East-to-West load areas, thus resulting in a weakened system [30].

Overload occurred on the 400 kV line; hence it tripped the line [30] and caused this blackout event. At the time of occurrence, the 400 kV parallel lines connecting the East and West of Turkey were carrying 4 700 MW, a load above the design and operation limits over a long distance. During the time in which a line carrying 1127 MW tripped on overload [32], the event affected the machine speed, which translated into a loss of synchronism between the Eastern and Western parts of the system and therefore it initiated angular instability.

Attaining of the equilibrium state was not successful and initialising of an angular instability subsequently affected the entire system due to a lack of N-1 contingency. The incident occurred during scheduled maintenance and as a result of the capacitor banks that were out of service [30]. The ability of the system to provide reactive power support was therefore compromised. A lack of awareness of the criticality of having enough reactive power supply for improving the angular stability of the system contributed to the blackout. A loss of synchronism led to the frequency decay, resulting from the failure to attain equilibrium, the load-shedding operation was not successful. The disconnection of thermal generator stations at frequencies higher than 47.5 Hz made the mismatch worse, underlining the importance of an accurate load-shedding scheme [32].

2.9.2 India 2012 Blackout

The India blackout, from July 30, 2012 to August 1, 2012 [33], had several causes for system collapse:

- The transmission system was weak due to several outages in the system;
- There was a mismatch between power generation and demand, particularly between the Northern and Western regions, resulting in system overload;
- The protection system operation was not successful, causing system separation between the western region and the northern region [34].

The simulation of the event indicates that the generators, equipped with AVRs, were adjusting the voltage too close to the permissible limits under similar load conditions. The simulation, performed in the absence of the AVR, indicated the opposite when subjected to the same 3% increase in both real and reactive power [34] (see Figure 2-29).

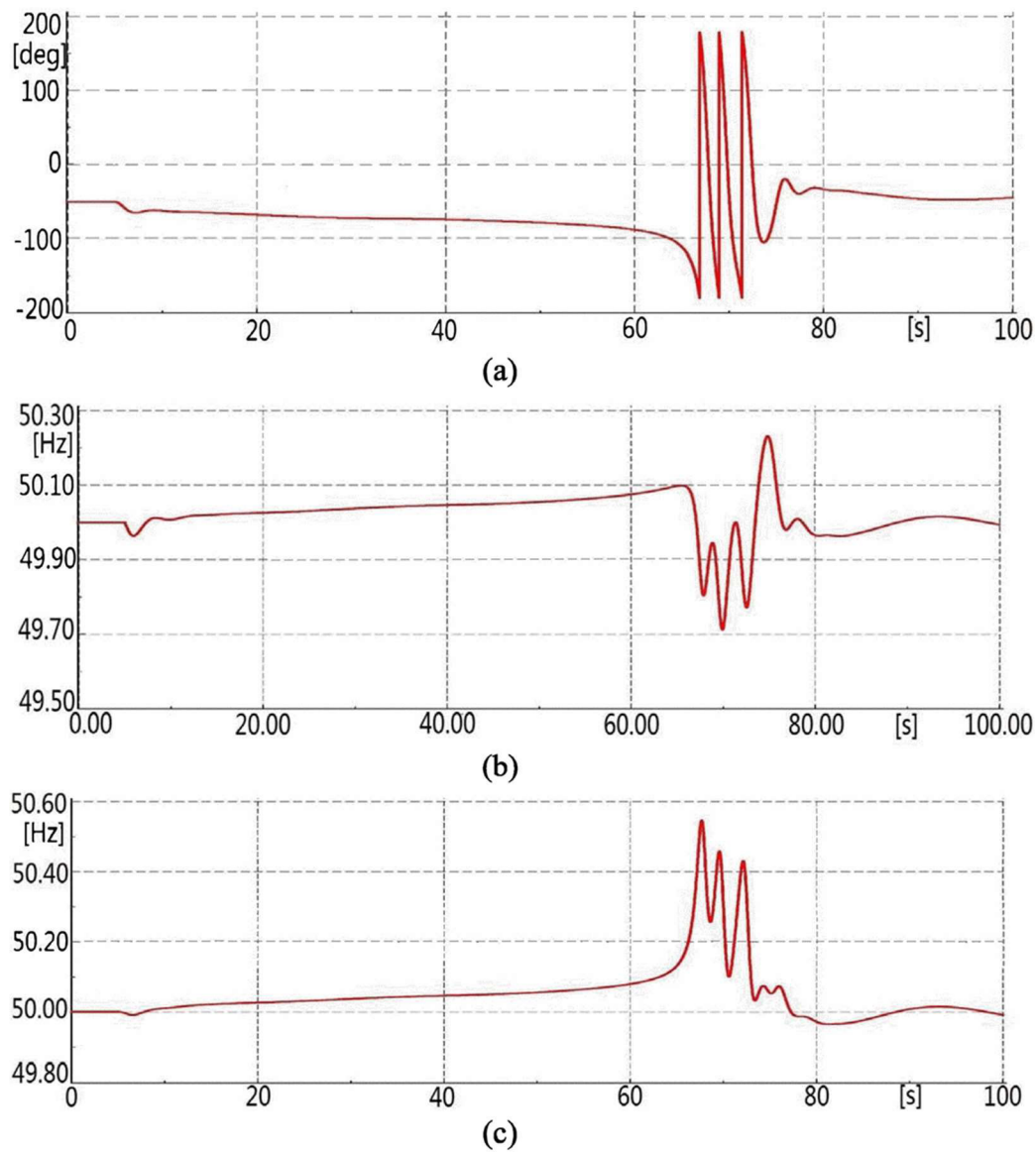


Figure 2-29: The angular difference between the northern and western regions (a), the frequency of northern region (b), and western region frequency (c) when subjected to an 3.5% increase in real and reactive power in the northern region

2.9.3 The 2003 Northeast blackout in the USA

In 2003, the Northeast USA and Canada blackout occurred due to a lack of technological up keeping and over 50 million people were affected by the power blackout. This led to a series of outages resulting into network pressure in the areas of New York City and up to and including Ontario, Canada. The system had more than 508 generating units operating in 265 power plants that shut down during the outage. The load connected to the system at the time was 28 700 MW prior to the outage. In the middle of the outage, the load suddenly dropped to 5 716 MW, a loss of approximately 80%, hence the mismatch in generation and demand [35].

The cost of power outages is hefty, the nature of generation and load mismatch is unpredictable and as such the possibility of blackouts exists due to various causes even in power systems of modern design and operation. The disconnection of generators created a gap in the requirement for additional active and reactive power that is crucial to maintaining stability. Equally important is reactive power injection into the system, which was lacking because five capacitor banks that were out of service as their disconnection from the system contributed to the occurrence of the system blackout [30].

2.9.4 Summary of causes of blackouts on selected global events

The main causes of the blackouts in the analysed incidents are consequences of inaccurate protection system operation in the India 2012 and Turkey 2015 events. The other incidents are attributable to consequences of inadequate reactive power supply, inadequate analysis of probable contingencies, operating the systems close to the stability limits and a lack of generator reserves to mention but a few [30].

2.9.5 The evolution of load-shedding in the Southern African Power Pool (SAPP)

In the Southern African countries, Eskom dominantly exports electrical power to a majority of the neighbouring power networks connected to it like Botswana, Lesotho, Namibia, and Swaziland. In 2007, the evidence of power shortage forced the utilities to operate at reduced reserve margins and later they implemented forced load-shedding. In 2008, a demand and supply imbalance confronted Eskom when it generated approximately 95% of the energy used in South Africa and had to rollout planned load-shedding [36]. In 2009, the available energy capacity in the region was approximately 46 722 MW for interconnected grids, while the peak demand was 41 645 MW for the same interconnected grid. This capacity left a minimal reserve margin of 10.2% and therefore it indicates the urgent need for contingencies to achieve continued power supply [37]. Even though Eskom was successful in avoiding load-shedding in 2014, in 2015, this power house experienced the highest load-shedding events due to the capacity constraints at the time [38].

2.10 History of load-shedding and blackouts in Lesotho

A tie-line connecting the Lesotho power system to Eskom comprises of a parallel double circuit; each circuit has a surge impedance loading of 60 MW (see Figure 2-30). In the past ten years, imported power has not increased to above this capacity. The line has been stable with only few incidents, thus, the root cause for the semi-blackouts that occurred can be categorised under inadequate situation analysis and operational errors. However, irrespective of the probable causes for a tie-line loss event, the system collapse is inevitable even in a situation in which the configuration of generators controls the active power injected and the voltage magnitude at the connected buses; and this is due to system constraints. The absence of event activated load-

shedding leaves the system vulnerable, which in turn calls for the evaluation of contingencies when such undesirable conditions arise. Some of the contingencies that threaten the system stability are faults on the tie-line or loss of the tie-line, as well as the faults at the Eskom Maseru Bulk (EMB) switching station.

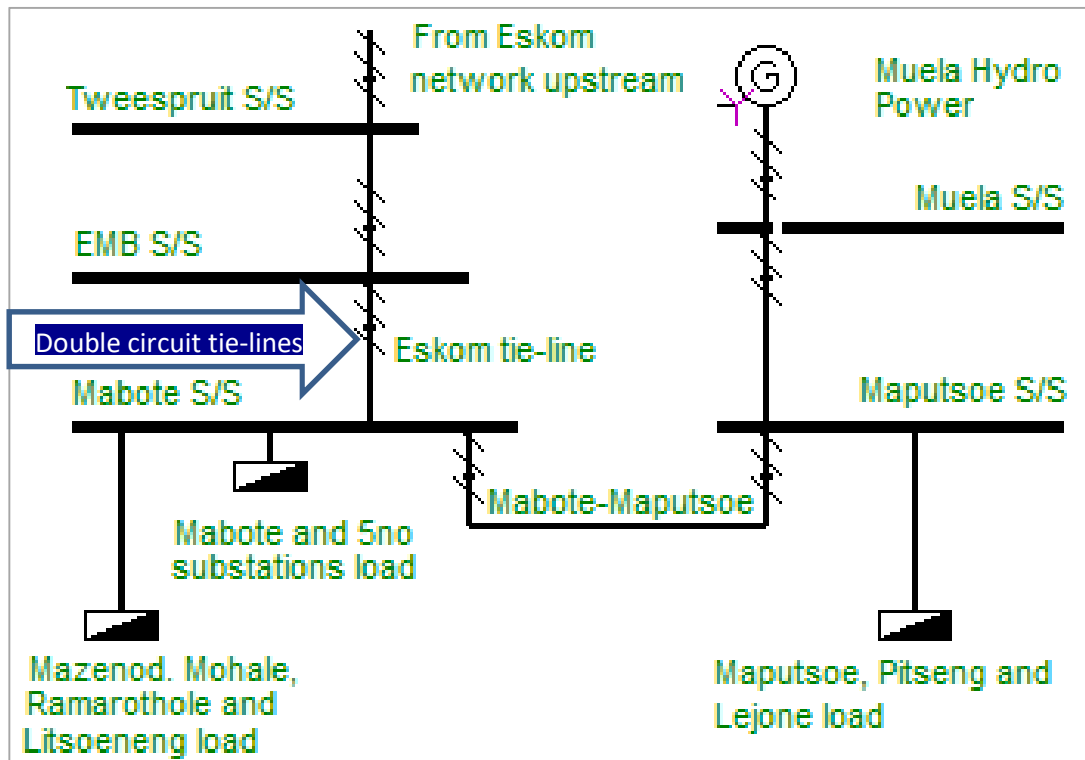


Figure 2-30: Schematic diagram showing the tie-lines connection between Eskom and LEC network

2.10.1 Lesotho Semi-blackout on 8th May 2016

This semi-blackout occurred on 8th May 2016 from 23:13 to 23:38 as a result of the incorrect configuration of the 132 kV incomer circuit breaker connecting the Mabote 132 kV substation and the EMB 132 kV switching station. The circuit breakers on the incomers were configured such that the operation of the circuit “1” incomer did not affect the status of circuit “2”, while operating circuit “2” resulted in the activation of circuit “1” operation. Switching circuit 2 activated tripping of both circuit breakers and switched off both 132 kV incomer circuits. Because both the incomer lines were out of service, this resulted in system overload followed by a semi-blackout on the large part of the system supplied from EMB substation. The occurrence of this event equates to switching off both 132 kV incomers either at Mabote or EMB substation, and overloading the hydro generators under heavy winter load conditions.

2.10.2 Lesotho blackout on 16th March 2018 (06:00 to 09:00)

This recent semi-blackout occurred on 16th March 2018 and it emanated from the mismatch between supply and demand, due to reduced supply from the Eskom lines. Eskom reduced power supply due to maintenance on one line upstream to the EMB substation. Due to this maintenance, Eskom limited its power export to the Lesotho power system to 30 MW, an amount that was not enough to meet the load condition then. The system collapsed for over three hours. This blackout directly affected the normal running of eight towns and all industrial areas.

2.11 Summary

The source of commercial power in the power market is generators, sometimes referred to as synchronous machines and their deployment aids the conversion of mechanical energy into electrical energy. To meet the ever-changing demands, the units' governors increase or decrease turbine power, thus controlling the system frequency close to its nominal value. During operation of the power system, the load connected to the system changes from time to time. During system operation, the occurrence of sudden load changes causes electromechanical oscillations as well as rotor angle swings; these both need damping to maintain system stability. In transmitting power, the quality of power is crucial and so is the balance between power generation and demand. An increase in load that results in a decrease in frequency beyond a point at which frequency stability is threatened, also contributes to complete system collapse. The flow of reactive power in the system supports the control of voltage at specific nodes and thus achieves regulation of voltage within preferred operating points.

Excitation systems are the principal sources of reactive power. The combined excitation system functional blocks aid in the maintenance of the terminal voltage of the generator by applying proportionally direct current to the field winding of the generator. To increase generator terminal voltage, its field current controls increases proportionally. The automatic voltage regulators keep the terminal voltage within the set limits.

The capacity of a power system is established through the modelling of the system load-flow study to guarantee safety and reliability. A load-flow study is also a prerequisite for advanced studies such as a short-circuit analysis, power quality, power system dynamics, etc. To achieve system stability, one of the contingencies aids resorted to is underfrequency load-shedding to unload the network to preserve frequency within specified limits and avoid system collapse. The bus voltage and reactive power relationship is equally important for stability purposes, as a system is stable when injection of reactive power results in an increase in voltage at all voltage busbars

and the opposite defines a voltage unstable system. The methods of regulating reactive power flow include shunt capacitors, shunt reactors, SVCs, STATCOM, etc.

CHAPTER 3 THEORETICAL DESIGN

Chapter 2 discussed the principal concepts relating to the control of voltages through the control of various excitation system functional blocks. It further dealt with the variables contributing to the change in frequency and extent of impact that frequency has on the active power transfer. The chapter also included a discussion on an incident demonstrating the impact of power mismatch during the loss of a tie-line when a tie-line disconnection or fault on the line led to failure to achieve a load-flow solution and eventually escalated into system collapse.

Chapter 3 continues to discuss the Lesotho power system status quo in relation to the various technical elements as listed below:

- voltage levels at various busbars
- characteristics of synchronous generators
- the active power and reactive power control on the system
- under- and overfrequency load-shedding relays, and
- simulation of the past incidents to duplicate the system response thereto.

The system configuration discussion includes a single line diagram up-stream to the Maseru Bulk switching station, a point of connection for the LEC 132 kV system. The investigation covers the various blocks such as generators, transformers, transmission lines, distribution lines, loads, etc., that make-up the system with reference to the existing system capacity and loading. Simulations are also performed to emulate the operating settings on the currently installed undervoltage and underfrequency relays to evaluate the risks that lead to system collapse during the loss of the tie-line. The simulations demonstrate the system's behaviour, using 'existing relays' settings to duplicate the results during system dynamic conditions.

The stability of the power generating plant and control thereof, focus mainly on underfrequency activated load-shedding. The technicalities outside the boundaries of this investigation are neither included nor dealt with in detail. The basis for successful modelling of the plant are measurements and recordings of signals during simulations of various dynamic conditions. The signals of focus are frequency response, reaction time of underfrequency protection relays and voltage characteristics during the disturbances.

3.1 System overview

Mabote substation is the central substation in Maseru, the capital town, and 'Muela Hydro Power Station is in the northern part of Lesotho. During the period of January to December 2007, the national maximum demand was approximately 109 MW; 'Muela hydropower station generated 84.65 MW and the surplus was imported from Eskom. In 2016, the national demand was in the range of 150 MW; the much larger shortfall was still imported from Eskom and Mozambique (via Eskom's grid).

Generally, the amount of generation can be varied to meet load demand, this is not possible in the case of the Lesotho power system when the Eskom / Mabote tie-line or the EMB switching station is out-of-service. This bottleneck forces the system to transit into island operation with reduced loading or the system collapses when there is no equilibrium in supply/demand. In island condition, frequency activates and deactivates frequency responsive loads as a mechanism of regulation to avoid a blackout situation [6]. Underfrequency load-shedding is used to further reduce the system load.

3.2 Overview of the system modelling approach

The network model for this investigation does not explicitly model the part of the network at lower voltage levels, such as 11 kV and below. In the load flow, calculations assume balanced load conditions and only consider positive sequence components. The voltage control methods rely on automatic transformer tap adjustments.

3.3 System configuration of the 132 kV system

LEC procures power from three main sources viz, 'Muela Hydro Power Plant (72 MW) (LHDA), Eskom (South Africa) and Electricidade de Mocambique (EDM) (Mozambique). The connection to Lesotho comes via the Eskom grid at EMB, a switching station situated in Ladybrand in the Free State. EMB substation draws power from a 132 kV network at a substation located in Tweespruit, also in Free State province. The upstream Free State network on the Eskom grid comprises of three load centres, namely Bloemfontein, Kimberly, and Welkom. EMB substation derives its connection from Bloemfontein Free State network through Merapi 275 kV/ 132 kV substation. The recorded load in Bloemfontein in 2013 was 487 MW and the projected load forecast for 2022 is 649 MW; the estimated annual average load increase is 3% [39].

There are other points of connection to the Lesotho grid including an 88 kV line from Clarence feeding Letšeng Diamond Mine through Khukhune substation, and a 22 kV connection point in the Qacha's nek district. This investigation focuses on the network that connects to EMB substation. The transmission of power to the various load centres is through six 132 kV

transmission lines (see Figure 3-1), all the transmission lines use bare conductors for the transmission of power between the substations, i.e.:

- a The central substation is the Mabote 132/33 kV, 120 MVA substation that connects to Maputsoe, 132/33 kV, 40 MVA through a double circuit 132 kV overhead line and connects to Mazenod 132/33 kV, 80 MVA through another double circuit overhead line.
- b The transfer of power between 'Muela hydropower plant 132/11 kV, 96 MVA to other stations is through Maputsoe 132/33 kV, 40 MVA substation through 132 kV double circuit overhead lines.
- c Maputsoe substation connects radially to the Pitseng 132 kV/ 66 kV/ 11 kV, 20 MVA substation that feeds the Lejone 132 kV /66 kV/ 11 kV, 40 MVA substation.
- d The last station with a 132 kV double circuit radial configuration central to the load of the system is Mazenod 132 kV/ 33 kV, 120 MVA substation, which feeds the Mohale 132 kV/ 11 kV, 20 MVA substation through a 132 kV single circuit, which is the last station in the central part of the country.
- e Ramarothole 132 kV/33 kV, 20 MVA draws power from the Mazenod 132 kV substation and transfers power radially to the Litsoeneng 132/33 kV, 40 MVA substation through a single circuit 132 kV line, which is the last 132 kV station in the southern part of the country.

Figure 3-1 depicts the single line diagram (SLD) for the 132 kV network in which the magenta colour indicates the 132 kV network and the dark grey colour indicates the 33 kV network; Annexure 1 portrays a larger version of the SLD for better visibility. It is important to note that Figure 3-1 does not indicate most 33/11 kV substations, the limit of the DlgSILENT licence used in this study is 50 nodes; the complete power system SLD exceeds this limit. To reach remote and rural areas of the country, the 132 kV transformers step down the transmission voltages to distribution voltages at approximately 45 substations. Among these 45 substations, Mabote 33/11 kV, Mazenod 33/11 kV, Litsoeneng 33/11 kV, Khukhune 33/11 kV as well as Ramarothole 33/11 kV are crucial for the supply of power to the dense areas, namely the industrial, commercial, and household areas that have higher loads.

It is crucial to control the power supply to these stations during the loss of a tie-line condition to keep the system live. The utility carries out load-shedding operations at a 11 kV voltage level, which entail disconnection of the less essential loads at these substations.

Figure 3-1: Overview of the Lesotho 132 kV power system layout

Table 3-1 presents the schedule of transmission lines transmitting power at 132 kV voltage level. From the loading information in the table and the system configuration, the capacity of the network can accommodate future expansions subject to the increase in imported power or generation increase to accommodate growth in both the household as well as industrial loads. Only the Eskom tie-line and the Muela Hydro–Maputsoe lines have a loading of more than 30% of their rating.

Table 3-1: Schedule of loading on the 132 kV transmission system

Transmission line name and voltage level	u, Magnitude (terminal i) in p.u	Loading (%)	Capacitive Losses (Mvar)	Total Active Power (terminal i) in MW	Total Reactive Power (terminal i) in Mvar	Total Apparent Power (terminal i) in MVA
Eskom Tie-line L1 132 kV	0,95	18,88	0,20	39,27	11,17	40,83
Eskom Tie-line L2 132 kV	0,94	18,88	0,20	- 39,22	- 11,17	40,78
Everest-Merapi 275 kV	1,01	4,39	99,11	- 52,89	- 35,59	63,75
Harvard-Merapi 275 kV	1,00	11,51	98,56	183,98	- 110,50	214,61
Mabote-Maputsoe L1 132 kV	0,96	11,38	2,72	23,87	5,12	24,41
Mabote-Maputsoe L2 132 kV	0,96	11,38	2,72	23,86	5,12	24,41
Mabote-Mazenod 132 kV	0,94	12,39	1,62	52,65	8,04	53,26
Maputsoe-Pitseng 132 kV	0,96	3,26	1,45	6,74	- 2,47	7,18
Mazenod-Ramarothole 132 kV	0,94	6,48	2,36	13,82	- 1,54	13,90
Mazenod-Mohale Dam 132 kV	0,94	1,19	2,59	0,73	- 2,45	2,56
Merapi-Tweespruit 132 kV (L1 and L2)	1,01	12,66	14,73	83,46	13,13	84,49
Muela Hydro-Maputsoe L1 132 kV	1,00	17,23	2,92	35,93	13,32	38,32
Muela Hydro-Maputsoe L2 132 kV	1,00	17,23	2,92	35,93	13,32	38,32
Perseus-Everest 275 kV	1,00	26,15	119,44	465,34	- 139,31	487,74
Perseus-Harvard 275 kV	1,00	37,90	60,91	693,22	- 122,83	704,02
Pitseng-Ha Lejone	0,96	2,01	2,32	4,12	- 1,60	4,42
Ramarothole-Litsoeneng	0,93	4,70	2,00	9,89	- 0,22	9,89
Tweespruit 132 kV L1	0,97	18,86	2,26	39,92	11,05	41,42
Tweespruit 132 kV L2	0,97	18,86	2,26	39,92	11,05	41,42

The operating temperature and the clearance of the conductor from ground determines the thermal rating of the conductors. In Table 3-1, the loading on the lines is low and the thermal loading limits are not a concern. The assumption is that the switchgear ratings at the end of the transmission lines permit full power transfer to the load centres.

3.4 Evaluation of system loading for a year

LEC provided 30-minute metering data for all the 132 kV substations together with a summary of the power consumption for the period January 2010 to May 2014. Figure 3-1 portrays a summary of the consumption for the year 2013 from January to December only. A profile of the active power and reactive power (see Figure 3-2 and Figure 3-3) depicts relatively good system power control during the peak period in July 2013.

Because of the large amount of 30-minute metering data, the computation of the profiles makes use of a moving average technique that makes use of per month data computation. This technique is based on equation 3-1 [40] in which the derivation of moving average computation stems from computing the first 1440 points in a moving average trend.

$$F_t = \frac{A_t + A_{t-1} + \dots + A_{t-n+1}}{n} \quad (3-1)$$

To better understand the power profile for the peak period in July 2013, the profile was plotted to establish the pattern of use on a daily basis. The profile was further condensed to an hourly basis to determine the peak active and reactive power consumption. During the peak period in July 2013, the trended actual data plot depicts the highest loading occurring between 08:00 and 9:30; the times when the industrial and commercial sector are in full operation (see Figure 3-4 and Figure 3-5). From both Figure 3-4 and Figure 3-5, there is no direct correlation between the magnitude of active power (MW) and reactive power (Mvar) consumed.

LEC provided another set of data in a form of summaries of the monthly active power (MW) and apparent power (MVA) loading for the year 2017. Based on the loading data for the year 2013 and 2017 that is presented in Figure 3-2 to Figure 3-7, the reactive power demand is low during the peak. The conclusion is that the higher active power consumption does not directly relate to the reactive power demand, thus, the load profile shows that the load in the system reacts differently during different loading conditions.

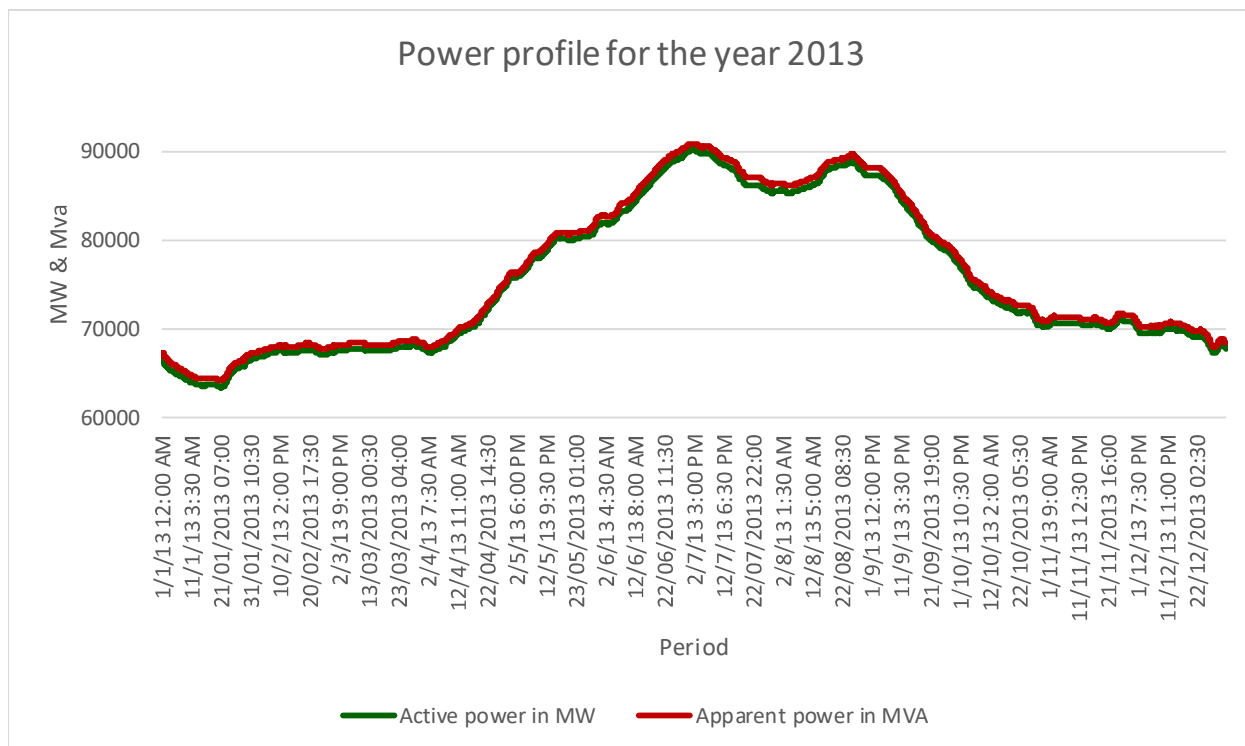


Figure 3-2: Summary of active power in MW and apparent power in MVA for the year 2013

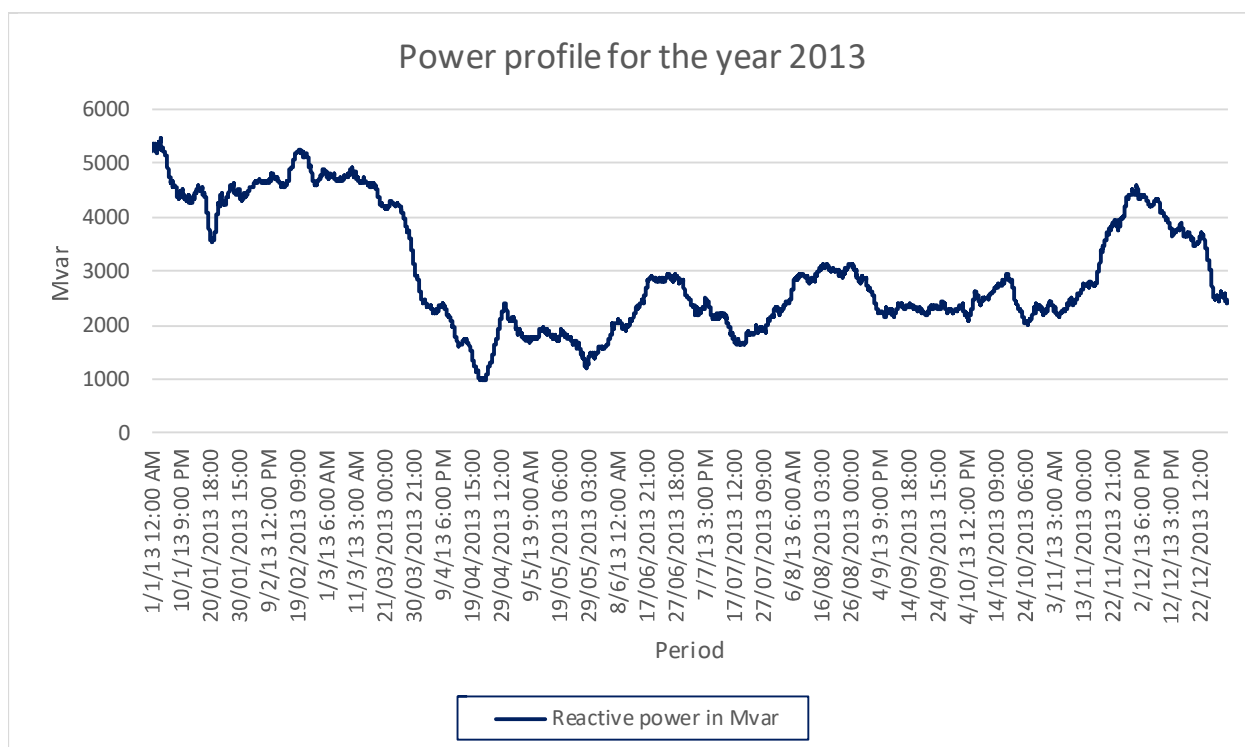


Figure 3-3: Summary of reactive in Mvar for the year 2013

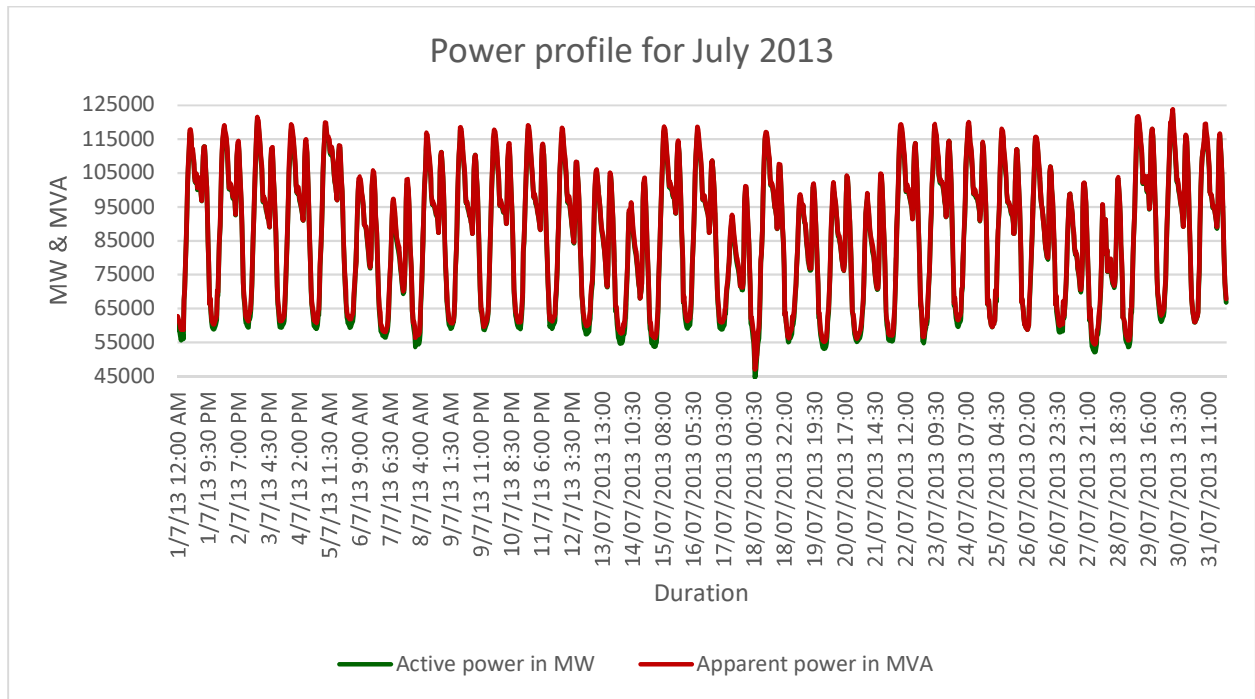


Figure 3-4: The active and apparent power consumption trend for July 2013

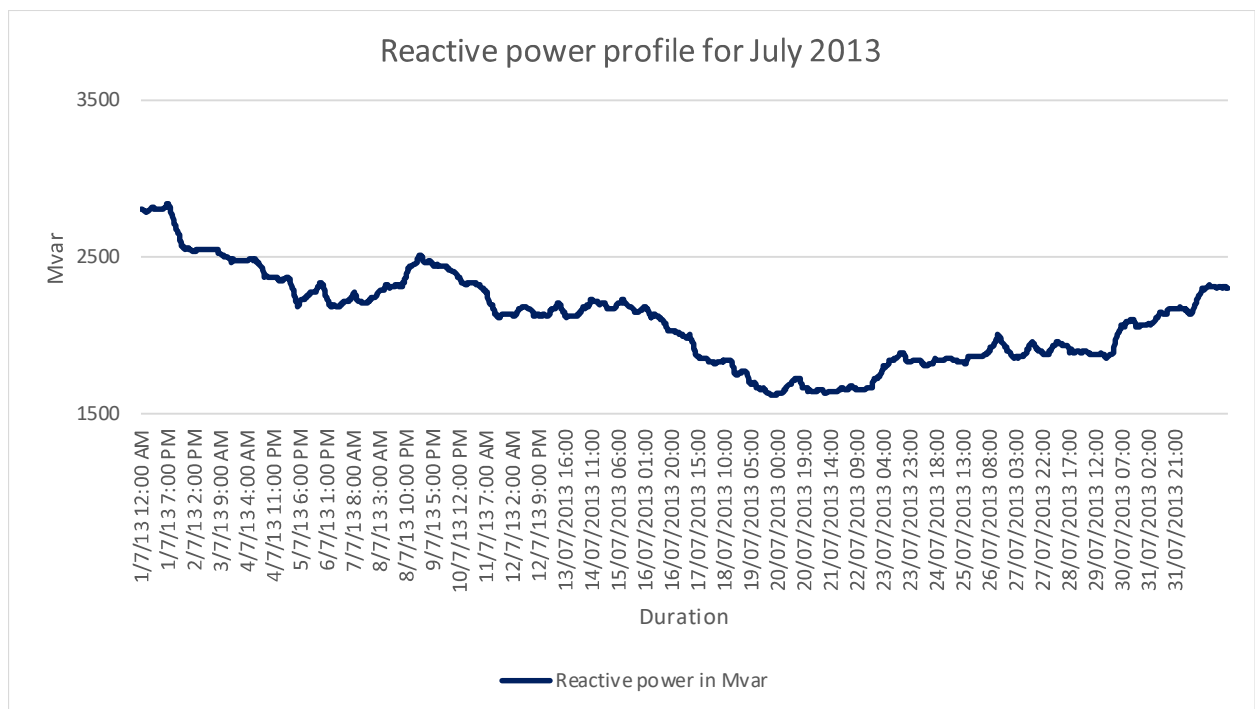


Figure 3-5: The reactive power consumption trend for July 2013

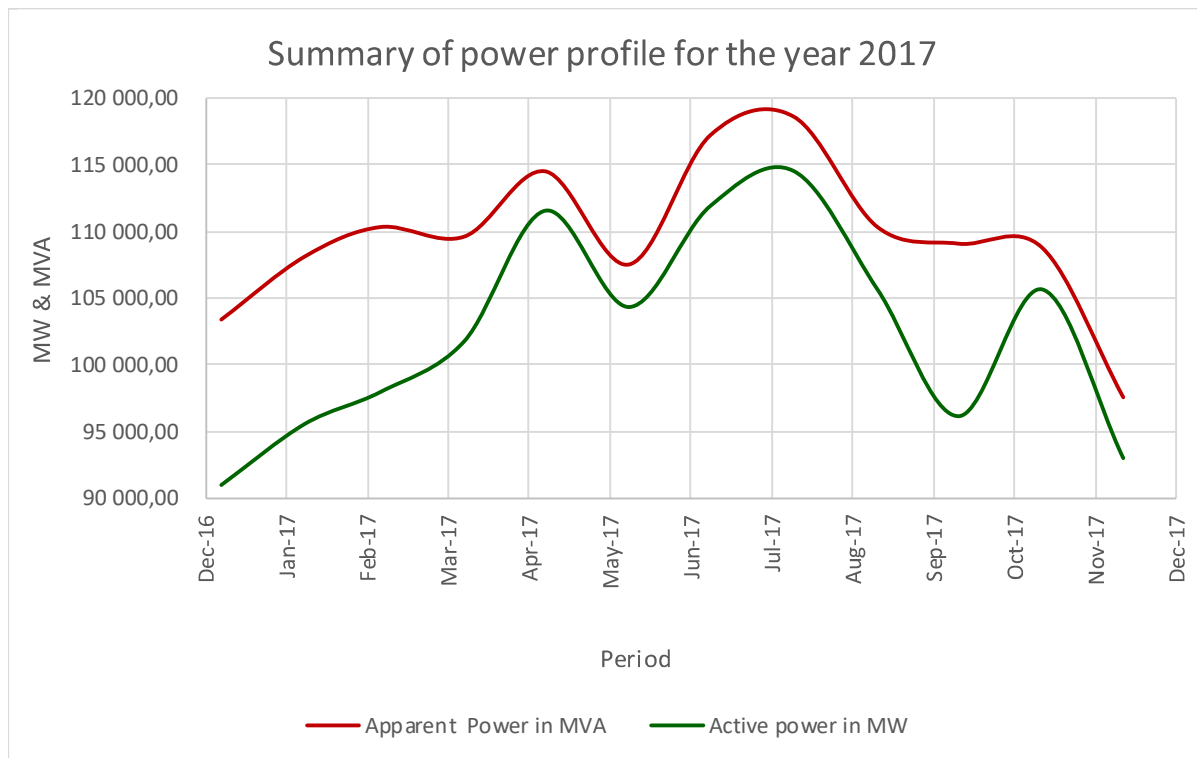


Figure 3-6: Summary of the active in MW and apparent in MVA power loading for the year 2017

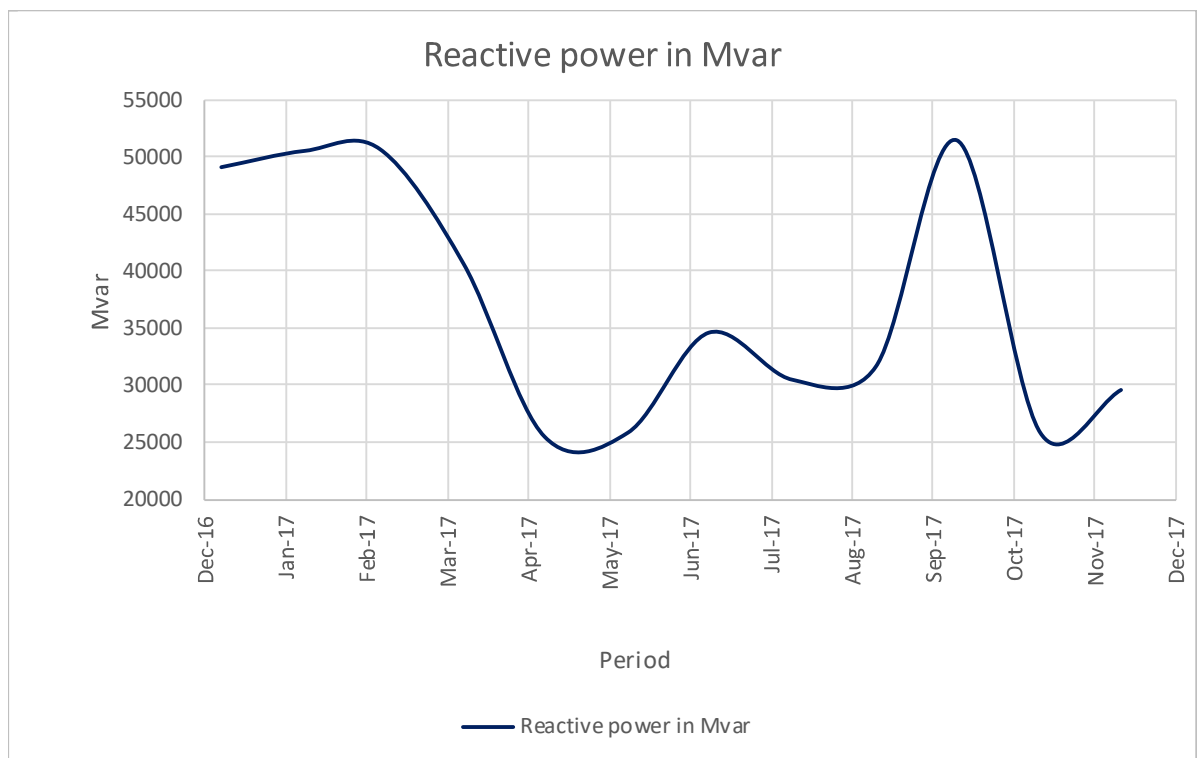


Figure 3-7: Summary of reactive in Mvar power loading for the year 2017

3.5 Voltage and frequency dependency of loads

The load profiles for the years 2013 and 2017 cannot definitively determine the composition of the load and determine whether it is static or dynamic. For simulation purposes, the Lesotho power system load composition is aligned to the default values for a three-phase balanced load that has the voltage dependency kpu of 1.6 and kqu of 1.8 in equation 3-4 and 3-5 [12]. From 3-4 and 3-5, the load composition assumes that the division of load was nearly equal between static and dynamic conditions considering the peak load of 120 MW and off peak load of 61.06 MW for the week ending 31st July 2013. In DigSILENT [12] equations 3-2 and 39 present the polynomial terms in which the subscript '0' denotes the operating point values.

$$P = P_0 \left(aP \left(\frac{v}{v_0} \right)^{e_{-aP}} + bP \left(\frac{v}{v_0} \right)^{b_{-cP}} + (1 - aP - bP) \left(\frac{v}{v_0} \right)^{e_{-cP}} \right) \quad (3-2)$$

$$Q = Q_0 \left(aQ \left(\frac{v}{v_0} \right)^{e_{-aQ}} + bQ \left(\frac{v}{v_0} \right)^{b_{-cQ}} + (1 - aQ - bQ) \left(\frac{v}{v_0} \right)^{e_{-cQ}} \right) \quad (3-3)$$

Where

$(1 - aP - bP) = cP$, and v is the busbar voltage in per unit

$(1 - aQ - bQ) = cQ$, and v is the busbar voltage in per unit

During dynamic conditions, the DigSILENT load modelling considers the static portion of the load as constant impedance, this is calculated by equations 3-4 and 3-5.

$$P = P_0 \left(\frac{v}{v_0} \right)^{kpu} * \left(1 + k_{pf} \left(\frac{\Delta f}{f_0} \right) \right) \quad (3-4)$$

$$Q = Q_0 \left(\frac{v}{v_0} \right)^{kqu} * \left(1 + k_{pf} \left(\frac{\Delta f}{f_0} \right) \right) \quad (3-5)$$

DigSILENT [12] further determines the dynamic load part in equation 3-6 and the definition of the fraction of the load is dependent on the parameter T_{mo} in percentage.

$$t_e = \left[\frac{T_{mo}}{100} \right] \left[\frac{v^2}{v_0^2} \right] \left[\frac{s}{s_0} \right] \left[\frac{s_0^2 + s_{cr}^2}{s^2 + s_{cr}^2} \right] \quad (3-6)$$

3.6 System modelling

The Lesotho Electricity Company provided the base model used in this study. The model consists of power generation, transmission, distribution, loads, etc. The modifications on the model eliminated the distribution part because of the 50 nodes DigSILENT licence limit. The simulations

of load-shedding trips substations' loads at the 33 kV breakers and the extent of the voltage violations is evaluated on the 132 kV, 33 kV and 11 kV busbars. In steady-state, the initial conditions are calculated based on the assumed three-phase network comprising of complex phasors to compute active and reactive power flow, voltages, currents, etc., in the system.

Although ideally the design of the generators aims to produce balanced phase voltages, external sources such as the connection of unbalanced three-phase loads, single-phase loads, and the occurrence of short-circuit faults and open circuit faults in the power system cause imbalances in the system voltages. These external sources create unbalances in voltages and currents in the three-phase network. The elements that are included in the modelling are:

- the equivalent Eskom grid;
- generators;
- transmission lines;
- transformers, and
- loads.

Modelling the grid, Table 3-2 presents the grid model that comprises of the voltage source with internal impedance to indicate its physical characteristics. The acceleration time constant represents the combined inertia of all the machines connected to the system [1]. The secondary frequency bias (in MW/Hz) describes the dependency of active power on frequency [12].

Table 3-2: Grid parameters for RMS-simulation

Parameter description	Values	Units	
Acceleration time constant	1000	sec	
Secondary Frequency Bias	135	MW/Hz	
Max Values		Min Values	
Short circuit power S_k "max" (MVA)	28000	Short circuit power S_k "min" (MVA)	342.94
Short-circuit current I_k "max" (kA)	58.78	Short-circuit current I_k "min" kA	0.72
c-factor "max"	1.1		1
X/R ratio "max"	10		10
Impedance ratio "max"		Impedance ratio "min"	
Z_2/Z_1 max	1	Z_2/Z_1 min	1
X_0/X_1 max	1	X_0/X_1 max	1
R_0/X_0 max	1.1	R_0/X_0 max	0.1

Note: The computations used the maximum values to achieve stability in the DIgSILENT RMS-simulation toolbox.

If the frequency of the system changes during the simulations, the active power increases to simulate the behaviour of the control of generation and frequency (load/generation control). The model treats the external grid as a slack bus type. In Equation 3-7, the computation of the frequency bias presents changes in generation because of a change in frequency.

$$K_{pf-i} = \frac{\Delta P}{\Delta F} = \frac{89.67 \text{ MW}}{(50-49.2 \text{ Hz})} = 133 \text{ MW/Hz} \quad (3-7)$$

3.6.1 Modelling of generators

The composite models of the synchronous machines include the definition of control systems such as a voltage controller, governor (primary control unit) and power system stabilizer. Table 3-3 and Table 3-4 present the parameters used for modelling the hydro synchronous generators with the associated winding resistance, reactance as well as time constants. These parameters characterize dynamic behaviour of the generating units during faulted system conditions.

Table 3-3: Resistances, reactance, and time constant for 32 MVA generators [41]

Parameter description	Abbrev.	Value	Units
Stator windings resistance per phase	20°C	0.0080	Ω
Rotor windings resistance	20°C	0.038	Ω
Short-circuit ratio	kc	>0.9	p.u.
Direct axis synchronous reactance	X _d	1.04	p.u.
Quadrature axis synchronous reactance	X _q	0.6	p.u.
Direct axis transient reactance at rated voltage	X' _{ds}	0.14	p.u.
Direct axis sub-transient reactance at rated current	X'' _{ds}	0.12	p.u.
Negative sequence reactance	X ₂	0.13	p.u.
Zero sequence reactance	X ₀	0.07	p.u.
Open circuit transient time constant	T' _{do}	7	s
Short-circuit transient time constant	T'' _d	1.1	s
Short-circuit sub-transient time constant	T''' _d	0.03	s
Armature time constant	T _s	0.12	s
Voltage regulation when rejecting load at rated voltage, constant speed, and excitation current	0.39		p.u.

In conducting power system stability studies, fault and load-flow studies are paramount as they enlighten the derivation of the magnitude and angle of the generator voltage behind transient reactance. The dynamic simulation also helps to determine the appropriate transformer tap positions and reactance to control voltage variations.

3.6.2 Generator losses

The efficiency of a synchronous machine determines how much useful power it can generate. The generator losses comprise of a combination of the losses, i.e.:

- Resistive losses (I^2R) in the rotor and stator circuit;
- Iron losses due to presence of frequency in the stator cores;
- Mechanical losses resulting from friction in bearings and windage, and
- Stray losses resulting from the harmonic losses in the core and current flow in the core rather than flowing in the conductors.

Table 3-4 provides the synchronous generator system losses at the rated power output with both stator and rotor winding temperatures at 70 °C [41].

Table 3-4: Power generator(s) losses [41]

Type of losses	Minimum rating	Maximum rating	Units
Load	32	32	MVA
Power factor	0.85	1.00	p.u.
Efficiency	98.04	98.41	Percent (%)

3.6.3 Generator controls

To achieve realistic results during transient simulations, controllers were added to the synchronous machines' models to effectively analyse the behaviour of the system during faulted conditions, either on the busbars or on transmission lines. The controllers considered for each generating unit in the simulations are governors (also known as power control units), automatic voltage control units (AVR) and power system stabilizer (PSS).

3.6.3.1 Governor (power control unit)

In island condition, the three connected generators at 'Muela hydropower station share the changes in the load as per their individual permanent droop characteristics. The nominal system frequency governs the limits within which the generator's speed can vary. The load frequency control maintains a uniform and stable frequency to retain the load between Eskom and 'Muela hydropower station. Table 3-5 presents the settings for the gov_HYGOV model used for simulating the system behaviour during faulted conditions.

Table 3-5: Governor gov_HYGOV parameters [12]

Description	Abbreviation	Value	Units
Temporary Droop	r	0.1	p.u.
Governor time constant	T_r	10	s
Filter time constant	T_f	0.05	s
Servo time constant	T_g	0.3	s
Water starting time	T_w	0.51	p.u.
Turbine gain	A_t	1.15	s
Turbine rated power (0=pturb) MW	P_{turb}	0	MW
Functional losses factor	D_{turb}	0.01	p.u.
No load flow	qnl	0.08	p.u.
Permanent droop	R	0.04	p.u.
Minimum gate limit	G_{min}	0	p.u.
Gate velocity limit	V_{elm}	0.29	p.u.
Maximum gate limit	G_{max}	1	p.u.

3.6.3.2 Excitation system parameters

The model uses the IEEE T1 standard exciter model to control the generator terminal voltage during faulted conditions. Referring to the detailed space model in Annexure 2, the terminal voltage of the generator (u) is the input to the voltage measurement system that acts as the transfer function. Table 3-6 provides the exciter system parameters used.

Table 3-6: AVR system parameter used for modelling the system response [12]

Parameter description	Abbreviation	Parameter	Units
Measurement Delay	T_r	0.02	s
Controller Gain	K_a	100	p.u.
Controller Time Constant	T_a	0.05	s
Exciter Constant	K_e	1	p.u.
Exciter Time Constant	T_e	0.2	s
Stabilization Path Gain	K_f	0.0025	p.u.
Stabilization Path Time Constant	T_f	1	s
Saturation Factor 1	E_1	4	p.u.
Saturation Factor 2	S_{e1}	1.5	p.u.
Saturation Factor 3	E_2	6	p.u.
Saturation Factor 4	S_{e2}	2.5	p.u.
Controller output minimum	V_{min}	0	p.u.
Controller output maximum	V_{max}	10	p.u.

3.6.3.3 Power system stabilisers (PSS)

The power system stabilizers (*PSS*) reduce the system voltage oscillations by providing a damping torque to the generator rotor oscillations. If the damping of oscillations is not adequate, the oscillations can be harmful to the system as they reduce the lifespan of the system components. Table 3-7 presents the parameters for a power system stabilizer “PSS2A” model.

Table 3-7: Power system stabilizer model PSS2A settings

Parameter description	Abbreviation	Parameter	Units
1th Washout 1th time constant	T_{w1}	1.5	s
1th Washout 2th time constant	T_{w2}	1.5	s
1 st Signal transducer time constant	T_6	0.015	s
2 nd Washout 1th time constant	T_{w3}	1.5	s
2 nd Washout 2th time constant	T_{w4}	1.5	s
2 nd Signal transducer factor	K_{s2}	0.5	s
2 nd Signal transducer Time Constant	T_7	1.5	s
1 st Washout coupling factor	K_{s3}	1.5	p.u.
PSS Gain	K_{s1}	3	p.u.
1 st Lead-lag derivative time constant	T_1	0.18	s
1 st Lead-lag derivative time constant	T_2	0.02	s
2 nd Lead-lag derivative time constant	T_3	2	s
2 nd Lead-lag derivative time constant	T_4	5	s
Ramp tracking filter derivative time constant	T_8	0.4	s
Ramp tracking filter derivative time constant	T_9	0.1	s
Ramp tracking filter	N	1	-
Ramp tracking filter	M	4	-
1 st Input selector	I_{c1}	1	-
2 nd Input selector	I_{c2}	3	-
Derivative factor	K_d	0.01	p.u.
IPB PSS base selector (1=gen MVA MW)	IPB	1	-
Controller minimum output	V_{stmin}	-0.05	s
Controller maximum output	V_{stmax}	0.05	p.u.

Under a disturbed system condition, because of a fault or a rapid change in load during the loss of a tie-line, the electrical power output changes. While the electrical output of the machine can change rapidly, the mechanical power in the system is relatively slow to change, causing the difference in speed response. The result of the difference in speed is the momentary imbalance between the mechanical input power and the electrical output power. A power system stabilizer (*PSS*) is added to the system to keep the system stable by improving the damping on the generator electromechanical oscillations [1] lack that can cause transient torque on the generator shaft if not arrested, resulting into severe mechanical damage [1].

3.6.4 Modelling of transformers

The transformers convert energy from one voltage level to another voltage level. To meet the voltage regulation requirements, the transformers are equipped with on-load tap changers (OLTC) to control the voltage, phase angle or both. In order to obtain the performance characteristics of the transformer, equivalent circuit models (see Figure 3-8) are used [21]. Referring to Figure 3-8, in computing primary voltage, the secondary parameters are referred to the primary side (see equation 3-8).

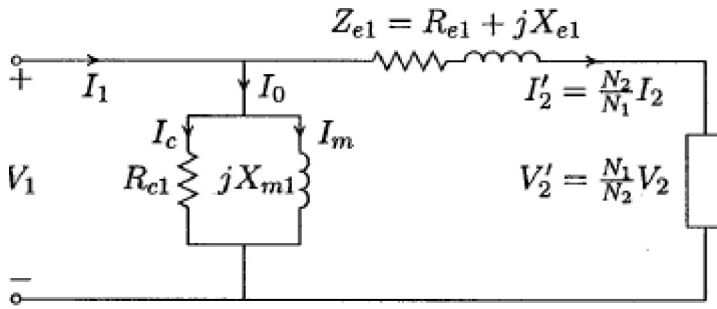


Figure 3-8: illustration of equivalent circuit in reference to the primary [21]

$$V_1 = V'_2 + (R_{e1} + jX_{e1}) * I'_2 \quad (3-8)$$

Where

$$R_{e1} = R_1 + \left(\frac{N_1}{N_2}\right)^2 * R_2 \quad (3-9)$$

$$X_{e1} = X_1 + \left(\frac{N_1}{N_2}\right)^2 * X_2 \quad (3-10)$$

$$I'_2 = \frac{S_L^*}{3V_2'^*} \quad (3-11)$$

3.6.4.1 Assumption in modelling

Most transformers in the Lesotho system have a three-phase, two winding configuration and a few have three-phase, three windings configurations. The two winding transformers are configured star-delta (YNd1), therefore they have phase shifts of $+30^\circ$. The system model uses a grounding transformer as part of an earthing system for all the 132 kV/33 kV transformers. The use of this configuration provides an artificial neutral by using a zigzag neutral earthing compensator with resistor (NECR) to improve earth fault detection, discriminative isolation of earth faults and to limit the over-voltage oscillations during the transient conditions in the power system.

3.6.4.2 Transformer performance

As mentioned in section 3.6.4 Modelling of transformers, the equivalent circuit parameters are useful in predicting the performance of transformers. Equation 3-12 calculates transformers at unit efficiency; the computations also consider the material used for the windings with the associated declared losses [21].

$$\eta = \frac{n \times S \times PF}{(n \times S \times PF) + n^2 \times P_{CU} \times P_C} \quad (3-12)$$

Where

$S = 3 \times V_2 \times I_2$, is full-load rating

$P_{CU} = 3 \times R_{e2} \times I_2^2$, is full-load copper loss for a three-phase transformer configuration

To achieve optimum efficiency in the system, the transformer should be loaded at its maximum efficiency point, where copper losses are equal to the core loss (see equation 3-133-13).

$$n = \sqrt{\frac{P_C}{P_{CU}}} \quad (3-13)$$

Regulation of a transformer's voltage output is key to comply with NRS 048 [2] or equal and approved standards. Varying the transformer's ratio (V_1/V_2) by means of an OLTC (see Figure 3-9) regulates the voltage to within declared limits.

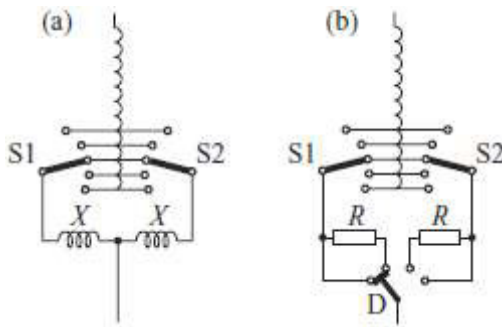


Figure 3-9: Illustration of an on-load tap changer using both a reactor (a) and resistor (b)

The voltage operating limits are set to regulate the system voltage. Under load conditions, the following exist:

- I^2R losses in the windings are dependent on the load, and
- The series reactance that causes a reactive voltage drop reduce the secondary voltage.

3.6.4.3 Transformer loading

Table 3-8 and Table 3-9 provide the loading on the two-winding transformers and three-winding transformers connected to 132 kV busbars respectively. Most transformers have low loads, indicating a potential to accommodate future network load increase with generation capacity or imported power permitting. The changes in taps are automatic to maintain voltages within $\pm 5\%$ of the permissible limits; the automatic tap changers have 16 taps. The stations with higher loadings are Mabote 132 kV/33 kV and 'Muela 11 kV/132 kV, loaded at 63.1% and 78.1% respectively.

Table 3-8: Schedule of loading on two-winding 132 / 33 kV transformers

Name	u, Magnitude (HV side) in per unit	u, Magnitude (LV - Side) in per unit	Loading (%)	Tap Position
'Muela Trf1 132/11 kV 32 MVA	1,0	1,0	78,1	9
'Muela Trf2 132/11 kV 32 MVA	1,0	1,0	78,1	9
'Muela Trf3 132/11 kV 32 MVA	1,0	1,0	78,1	9
Lits'oeneng Tfr2 132/33 kV 20 MVA	1,0	1,0	25,4	7
Lits'oeneng Trf1 132/ 33 kV 20 MVA	1,0	1,0	25,9	7
Mabote Trf1 132 / 33 kV 40 MVA	1,0	1,0	67,9	7
Mabote Trf2 132/33 kV 40 MVA	1,0	1,0	63,1	7
Mabote Trf5 132/33 kV 40 MVA	1,0	1,0	67,9	7
Maputsoe Trf1 132/33 kV 20 MVA	1,0	1,0	57,4	3
Maputsoe Trf2 132/33 kV 20 MVA	1,0	1,0	39,1	7
Mazenod Tx Tr1 132/33 kV 40 MVA	1,0	1,0	48,9	7
Mazenod Tx Tr2 132/33 kV 40 MVA	1,0	1,0	48,9	7
Ramarothole Trf1 132/33 kV 20 MVA	1,0	1,0	19,9	6

Table 3-9: Schedule of loading on three-winding 132 /66/ 11 kV transformers

Name	u, Magnitude (HV-Side) in per unit	u, Magnitude (MV-side) in per unit	u, Magnitude (LV-side) in per unit	Maximum Loading (%)
Ha-Lejone Trf1 132/66/11 kV 20 MVA	1,01	1,00	1,00	20,80
Ha-Lejone Trf2 132/66/11kV 20 MVA	1,01	1,00	1,00	20,80
Pitseng Trf1 132/66/11 kV 10 MVA	1,01	1,01	1,01	52,44
Pitseng Trf2 132/66/11 kV 10 MVA	1,01	1,01	1,00	10,75

3.6.5 Modelling of overhead lines

The overhead lines modelling is part of a static power plant. The basic electrical parameters for the overhead lines are conductor series impedance and shunt admittance. The line impedance consists of resistive and inductive components. The shunt admittance comprises

of the conductors' conductance to ground and the susceptance between each phase conductor to ground. The line conductance represents the component of current that is in phase with the applied voltage when energizing the line in open-circuit condition [42] [12].

DlgSILENT uses PI-circuit to represent the AC transmission lines (see Figure 3-10) wherein the subscripts s and r indicate the sending and receiving end of the lines respectively.

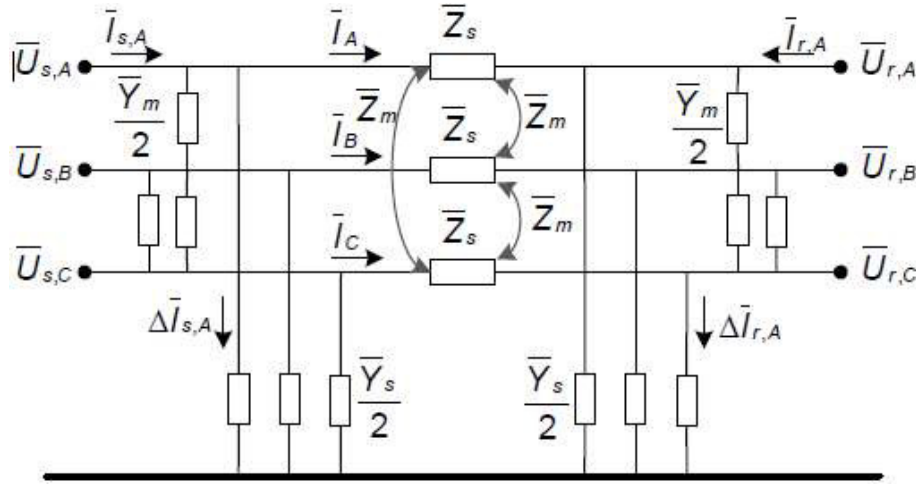


Figure 3-10: Equivalent PI-Circuit presentation of lumped parameters [12]

Equations 3-14 and 3-15 indicate the sending and receiving ends of the line longitudinal voltage drop along the line and currents at the sending end of the line. The basis for the formation of these parameters is the impedance and admittance matrices [12].

$$\begin{pmatrix} U_{s,A} & U_{r,A} & \Delta U_A & Z_s & Z_m & Z_m & I_A \\ U_{s,B} - U_{r,B} = \Delta U_B & Z_m & Z_s & Z_m \times I_B \\ U_{s,C} & U_{r,C} & \Delta U_C & Z_m & Z_m & Z_s & I_C \end{pmatrix} \quad (3-14)$$

$$\begin{pmatrix} I_{s,A} & \Delta I_{s,A} & I_A \\ I_{s,B} = \Delta I_{s,B} + I_B = \frac{1}{2} \times Y_s & Y_m & Y_m & Y_m & U_{s,A} & I_A \\ I_{s,C} & \Delta I_{s,C} & I_C & Y_m & Y_m & Y_s & U_{s,C} & I_C \end{pmatrix} \quad (3-15)$$

Equation 3-16 represents the current at the receiving end of the line.

$$\begin{pmatrix} I_{r,A} & \Delta I_{r,A} & I_A \\ I_{r,B} = \Delta I_{r,B} - I_B = \frac{1}{2} \times Y_m & Y_s & Y_m & Y_m & U_{r,A} & I_A \\ I_{r,C} & \Delta I_{r,C} & I_C & Y_m & Y_m & Y_s & U_{r,C} & I_C \end{pmatrix} \quad (3-16)$$

Equations 3-17 and 3-18 determine the natural impedance and admittance matrices of the line following the reduction of earth conductors in the system.

$$Z_{ABC} = \begin{bmatrix} Z_s & Z_m & Z_m \\ Z_m & Z_s & Z_m \\ Z_m & Z_m & Z_s \end{bmatrix} \times \begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix} \quad (3-17)$$

$$Y_{ABC} = \begin{bmatrix} Y_s & Y_m & Y_m \\ Y_m & Y_s & Y_m \\ Y_m & Y_m & Y_s \end{bmatrix} \quad (3-18)$$

While earth resistivity varies with the soil type, the resistivity values in the model range between 100 Ω to 150 Ω based on the soil properties for the longer portion of the line; modelling of the line in the rocky terrain assumes soil resistivity to be an average 150 Ω . Since all the transmission lines at 132 kV voltage level are less than 80 km they are short lines [12]. The basis for shunt capacitance calculation is formed on the lumped parameter, when compared to a more accurate approach using the distributed parameter approach used for lines longer than 240 km [42].

3.6.5.1 LEC 132 kV transmission lines

There is no line transposition in the Lesotho transmission system; the longest line between substations is less than 70 km. For analysis of the line performance, the computation allowances provide for current distribution over the line during unbalanced power flow or fault conditions [43]. The transmission lines that carry more load in the case of the Lesotho network have a double circuit configuration, while those feeding smaller remote loads have a single circuit configuration.

The 33 kV overhead line use a T-type pole structure for most part of the network, though there are short spans of concrete structures because of servitude constraints. Ideally, to achieve the desired impedance of the system, the parameters considered for computations are the conductor DC resistance, the diameter, and the internal inductance. The model, however, uses standard DlgSILENT line parameters instead (see Table 3-10). The physical structures of the lines for the Lesotho power system have single and double circuit configuration.

Table 3-10: Standard DlgSILENT overhead line parameters for system modelling

DESCRIPTION		Zbase	R	X	B	R0	X0	B0	Rating
	(MW)	(ohms)	(ohms/km)	(ohms/km)	(uS/km)	(ohms/km)	(ohms/km)	(uS/km)	(kA)
TWIN ZEBRA 275	258	756	0,03706	0,31914	3,7025	0,32519	1,13438	2,6446	1,30
SINGLE BEAR 132	46	174	0,12197	0,40650	2,8065	0,38037	1,22107	1,8365	0,50
SINGLE PANTHER 33	19	77	0,13939	0,41043	2,5826	0,47238	1,20032	2,0661	0,44

(a) Double circuit configuration

The 132 kV structures are similar for various lines; Table 3-11 shows the coordinates of the phase conductors and the earth wires for the double circuit configuration. Ideally, the characterisation of the line coupling technique for the modelling of mutual coupling between the parallel lines would improve the frequency dependence of the line's performance, however, the model instead uses standard DlgSILENT line parameters for all transmission and distribution lines.

Table 3-11: The coordinates of double circuit, 132 kV line structures

Coordinates of earth wires (m)							
	X	Y					
Earth wire 1	1,245	31,15					
Earth wire 2	4,845	31,15					
Coordinates of phase circuits (m)							
	Number of p	X1	X2	X3	Y1	Y2	Y3
Circuit 1	3	0	0	0	17,1	22,6	27,8
Circuit 2	3	7,2	7,2	7,2	17,1	22,6	27,8

(b) Single circuit configuration

The lines feeding remote low loaded load centres are of single circuit construction. Table 3-12 indicates the coordinates of the single circuit 132 kV line structures.

Table 3-12: The coordinates of single circuit, 132 kV line structures

Coordinates of earth wires (m)							
	X	Y					
Earth wire 1	3	29,3					
Coordinates of phase circuits (m)							
	Number of p	X1	X2	X3	Y1	Y2	Y3
Circuit 1	3	0	6	0	22,2	24,2	26,2

(c) 33 kV overhead line structure

The flat T-structure that has the coordinates shown in Table 3-13, dominates the construction of the 33 kV overhead line with minor line structure deviations because of site constraints. The model omits the portions of the 33 kV overhead lines in which the

line transits from one tower type to the other. The system modelling makes use of the general DigSILENT parameters for overhead lines, not the geometric coordinates system.

Table 3-13: The coordinates of single circuit, 132 kV line structures

Coordinates of earth wires (m)							
	X	Y					
Earth wire 1	1	14					
Earth wire 2	3	14					
Coordinates of phase circuits (m)							
	Number of p	X1	X2	X3	Y1	Y2	Y3
Circuit 1	3	0	2	4	10,6	10,6	10,6

3.6.5.2 Self-inductance

The computation of self-inductance follows the computing of the geometric mean radius (GMR). The definition of GMR (see equation 3-20) describes it as the equivalent hollow conductor with zero thickness producing no internal flux, giving the same self-inductance (L_{ii}) (see equation 3-19).

$$L_{ii} = \frac{\mu}{2\pi} \times \log \frac{2h}{GMR} + \Delta L_{ii} \quad H/kM \quad (3-19)$$

$$GMR = r \times e^{\left(-\frac{\mu r}{4}\right)} = r \times 0.7788 \quad (3-20)$$

3.6.5.3 Line resistance model

The resistance of the line has a considerable effect on the transmission line and cables' power transfer capacity, thus, an increase in temperature causes an increase in resistance. Equation 3-21 calculates the resistance value at a given temperature to achieve the load-flow solution.

$$R_{max} = R_{20} [1 + \alpha(T_{max} - 20^{\circ}C)] \quad (3-21)$$

Where

R_{20} is the resistance at temperature $20^{\circ}C$

α is the temperature coefficient in K^{-1}

T_{max} is the maximum temperature

R_{max} is the resistance at temperature T_{max}

3.6.5.4 Line capacitance model

When the line is live, the lines develop a charge at both ends between the phases and between individual phase and ground. According to [44], equation 3-22 indicates the line-to-neutral capacitance in a three-phase overhead line configuration (see Figure 3-11 in which the spacing between the lines is not identical).

$$C_n = \frac{0.0388}{\log_{10}(\frac{D_{eq}}{r})} \mu F \text{ to neutral} \quad (3-22)$$

Where $D_{eq} = \triangle D_m = (D_{ab} \times D_{bc} \times D_{ca})^{\frac{1}{3}}$

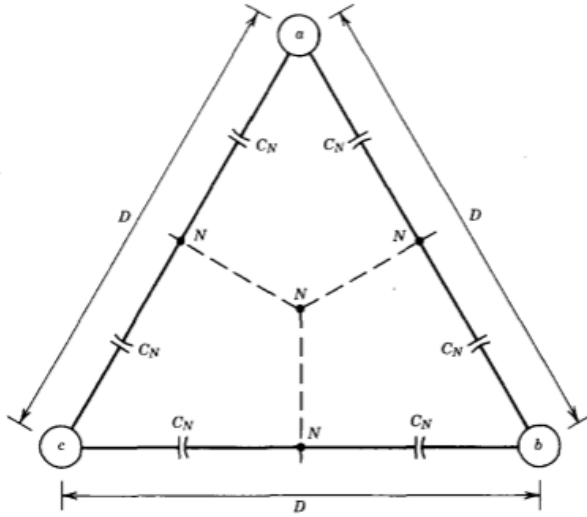


Figure 3-11: Three-phase line with identical spacing between all phases [44]

3.6.6 Modelling of the loads

The various loads connected to the system fall under either dynamic or static loads. The dynamic loads refer to a fast response to voltage and frequency changes under steady-state conditions. The static load refers to the typical behaviour of load at any point in time versus bus voltage magnitude and frequency (see equations 3-23 and 3-24) [1]. The static loads are categorised (also commonly called ZIP) into three categories, viz:

- Constant impedance / admittance (Z);
- Constant current (I), and
- Constant power / MVA (P)

Equations 3-23 and 3-24 provide the polynomial model of the loads.

$$P_A = P_0(p_1 \times \tilde{V}^2 + p_2 \tilde{V}^2 + p_3) \quad (3-23)$$

$$Q_A = Q(q_1 \times \tilde{V}^2 + q_2 \tilde{V}^2 + q_3) \quad (3-24)$$

Where

$$\tilde{V} = \frac{V}{V_0}$$

p_1, p_2, p_3 are fractions of constant impedance (Z), current (I) and power (P) for active power respectively.

q_1, q_2, q_3 are fractions of constant impedance (Z), current (I) and power (P) for reactive power respectively.

To account for frequency dependency of loads, Equations 3-25 and 3-26 are modified to Equations 3-25 and 3-26 respectively by the factors that take into account the real power frequency dependency factor, reactive power frequency dependency factor and frequency deviation.

$$P_A = P_0(p_1 \times \tilde{V}^2 + p_2 \tilde{V}^2 + p_3)(1 + K_{pf} \Delta f) \quad (3-25)$$

$$Q_A = Q(q_1 \times \tilde{V}^2 + q_2 \tilde{V}^2 + q_3) (1 + K_{qf} \Delta f) \quad (3-26)$$

Where

K_{pf} denote the active frequency dependency factor

K_{qf} denote the reactive frequency dependency factor

Δf denote frequency deviation

The model determines the typical active frequency dependency factor (K_{pf}) and reactive frequency dependency factor (K_{qf}) values in the ranges 0 to 3 and -2 to 0 respectively [45]. Table 3-14 indicates the different values for modelling of the inherent load behaviour. The value for voltage dependency on power (P) is 1.6 and that of voltage dependency on reactive power (Q) is 1.8 dynamic; these values are in line with the default DlgSILENT values for specification of the voltage dependency factors [12].

Table 3-14: Selection of the K_{pf}/K_{qf} value for different load model behaviours in DigSILENT [12]

Ratio	Value	Constant
K_{pf}/K_{qf}	0	Power
K_{pf}/K_{qf}	1	Current
K_{pf}/K_{qf}	2	Impedence

Considering the voltage dependency of loads, the calculation of the loads as per the base quantities, in relation to the load type, influence the outcomes of the study. In the case of the Lesotho power network, the calculated base quantities assume a combination of constant current and constant impedance because of the nature of the power load profile.

The load models considered are in the following forms:

- Devices or machines connected to the system that consume electrical power:
- Equipment or devices connected to the system that consume active and reactive power, and
- Portions of the system that are not represented in the network but consume electrical power.

For modelling purposes, some parts of 33 kV and 11 kV networks are not modelled explicitly. Some of the outgoing feeders at 33 kV voltage levels form lumped-load centres (referred to as composite loads) as they are sparse. The composite loads represent large fragments of load with associated active and reactive power requirements from the system. During steady-state condition, the composite loads' demand is more dependent on busbar voltage and the system frequency. The degree of dependency on frequency ($Q(V,f)$) and voltage ($P(V,F)$) is reliant on the real and reactive power requirements (static load characterization) [10].

3.6.7 Load-flow solution

The technique selected for modelling adopts balanced and unbalanced conditions to represent the power system active and reactive power balancing mechanism. The loading disparities neglected are those between the phases. The model uses the on-load tap changers to maintain the voltage within permissible limits, this application aims to avoid violation in the relationship between P, Q and V.

Table 3-15 provides the computation of the load-flow summary carried out at 20 °C for line or cable, transformers, etc.

Table 3-15: LEC power capacity summary

Description	Power (MW)	Reactive power (Mvar)	Apparent power (MVA)
Generation at Muela	76.8 MW	28.95 Mvar	76.80 MVA
External infeed	80.22 MW	27. 83 Mvar	82.99 MVA
Inter Grid Flow	0.00 MW	0.00 Mvar	
Load P(U)	150 MW	25.21 Mvar	151.97 MVA
Load P (Un)	150 MW	25.23 Mvar	152.11 MVA
Grid losses	7.14 MW	31.57 Mvar	
Line charging		-15.69 Mvar	
Compensation ind		0	
Compensation cap		0	
Installed capacity	81.60 MW		
Spinning reserve	4.80 MW		
Total power factor	1.00 [-]		
Motor / Load	0.99 [-]		

This summary is for the steady-state condition; in addition, the load-flow solution represents the active power control according to secondary control at the generation station. It provides the active power as well as the reactive power control of all the loads using the Newton-Raphson classical power equations for speedy load-flow convergence.

3.6.8 Excluded mini-hydro power stations

There are other small generation stations (see Table 3-16) that do not feed directly into the 132 kV transmission system.

Table 3-16: Summary of excluded mini-hydro generation stations in the model

Station Name	Generation capacity	Date of commissioning	Operational status	District
Tsoelike mini-hydropower plant	400 kW	1990	Not connected to the grid	Qacha'snek district
Tlokoeng hydropower station	670 kW	1990	Decommissioned in 2002	Mokhotlong district
Katse mini - hydropower	570 kW	2000	In operation	Thaba-Tseka district
Mantšonyane hydropower plant	2 MW	1989	In operation (partly)	Thaba-Tseka district
Semonkong hydropower plant	180 kW		In operation	Maseru district

3.7 Synchronous generator model

Power generated from the units at 'Muela hydropower is fed into the system and transmitted through the grid to contribute to the required combined system demand. During steady-state conditions, the generators share the impact of sudden power increase or decrease. During the system perturbations, the impact is first shared by the synchronous machines according to their synchronising coefficient followed by sharing according to their inertias [12]. Thereafter, the governors determine the power sharing between machines.

3.7.1 Impact of dynamic conditions on generator speed

Adding loads to the system forces the synchronous machines into acceleration to sustain the loads. Due to the short time constants between the action and reaction times, the prime mover's speed decreases the creation of an error between a set power value and a measured value. This activates the controller to increase the prime mover input to maintain the output close to the required values. In the event of an oscillating prime mover controller, the resulting effect is a frequency swing that creates time varying loads. The oscillations do not only cause fluctuations in power output, but also on the generator current swings, which subsequently result into voltage fluctuation [46].

3.7.2 Relationship between sending and receiving end power

Equation 3-27 determines the basis for sending end and receiving end maximum power transfer in which there is a close relationship between power (P) and angle (δ). Equations 3-28, and 3-29 respectively express the sending and the receiving end reactive power.

$$P = \frac{E_S \times E_R}{X} \times \sin\delta = P_{max} \times \sin\delta \quad (3-27)$$

$$Q_S = \frac{E_S^2 - E_S \times E_R}{X} \times \cos\delta \quad (3-28)$$

$$Q_R = \frac{E_S \times E_R - E_S^2}{X} \quad (3-29)$$

The maximum real power transfer therefore takes place if the sending end and the receiving end reactive power are equal in magnitude, but different in direction ($Q_S = -Q_R$), therefore ($Q_S = -Q_R = P_{max}(1 - \cos\delta)$).

3.8 System reactive power support

Table 3-17 shows that there is no reactive power support on the Lesotho power network; the network system relies on the Eskom system for additional reactive power support. The system under island operation relies on the following to alleviate voltage instability:

- generator reactive power output;
- transformer on-load tap changers for control of voltage limits;
- under-voltage load-shedding, and
- accurate and reliable coordination of the protections system.

3.9 Modelling underfrequency load-shedding

A tie-line loss from the external grid forces the system to operate in island mode if the system loading conditions satisfy the equilibrium requirements. Island mode exposes the generating units to different dynamic operational shortcomings, such as threatening the frequency stability in the event of failure to achieve equilibrium. This threat is a result of low system inertia, originating from the small size of the Lesotho power system relative to the grid (Eskom network).

3.9.1 Triggers for load-shedding

During an underfrequency load-shedding investigation, the following selected events initiated and triggered load-shedding operation:

- Eskom tie-line loss;
- Generator trip;
- Existence of overload condition during islanding, and
- Fluctuation of frequency beyond the set nominal operating limits.

During any of the above conditions, the available capacity is inadequate to sustain the continuity of power supply. In implementing underfrequency load-shedding by using the relay to detect decay in frequency and the load shed proportionate amount, the system achieves equilibrium that prevents it to collapse.

3.9.2 Installation and location of underfrequency relays

The underfrequency relays are located at the transmission substations and selected distribution substations to manage the supply/demand balance. To achieve this, the triggering command will activate a circuit breaker trip and thus isolate identified feeders supplying various substations at lower voltage levels, this maintains the system frequency within nominal values. Because of the concentration of the load relative to the tie-line connection

point, the consideration is tripping seven substations that connect directly to Mabote substation improves the system stability.

3.9.3 Design of load-shedding stages

Because of the loads' distribution over a wide geographical area and in radial configuration, a practical consideration is to load-shed the blocks of loads closer to the tie-line connection point to arrest the frequency decline. The rationale for performing load-shedding in stages is to avoid the following unfavourable consequences:

- Shedding more load than necessary in the initial stages to avoid overfrequency conditions or unnecessary loss of service to the customers, and
- Shedding too little in the initial stages which increases the risk of failure to arrest frequency decline, which results in a system collapse condition.

The established practise is to operate the network within the voltage and frequency limits of $\pm 5\%$ and $\pm 2\%$ respectively [47] (see Figure 3-12). From the recommended frequency range, the lower band of the steady-state operating frequency is set at 49.0 Hz, which is much lower than the 49.5 Hz prescribed by the Lesotho grid code [48]. This investigation uses the tie-breaker open status to activate UFLS stage 1, because of a requirement to drop the high value of load to sustain the supply/demand balance.

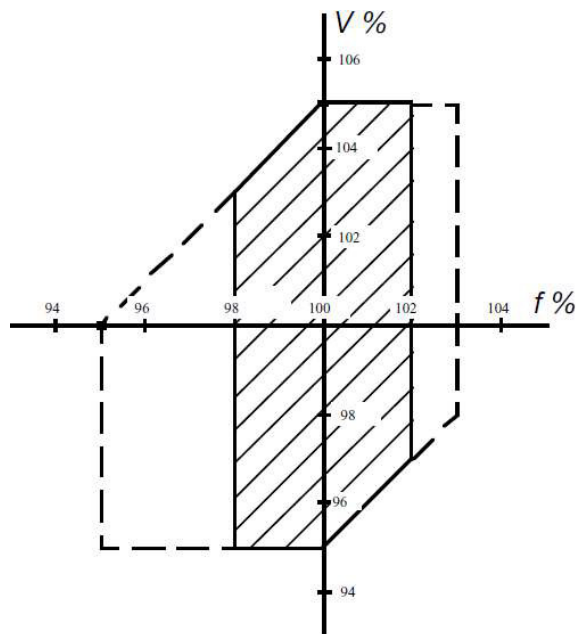


Figure 3-12: IEC 60034-3 generator operation boundaries for frequency and voltage [49]

3.10 Existing frequency and voltage relay scheme at Mabote 132 kV

The Lesotho power system does not control frequency when connected to the grid; SAPP jointly controls and maintains frequency for all the interconnected utilities [48]. The existing scheme

consists of voltage and frequency relays configured to monitor the installation at the 132 kV Mabote incomer. The relay utilises monitoring, recording faults, events, and disturbances functionalities. Some of the functions that are not utilized include tripping the breakers when frequency violations occur. The settings that are configured on site generate the warnings on voltage events only and it records the frequency events. Table 3-17 and Table 3-18 present the existing frequency and voltage relay settings at the Mabote 132 kV substation.

Table 3-17: Existing frequency relay settings

Under / Overfrequency protection settings						
Frequency settings	F1	F2	F3	F4	F5	F6
	48,5	51,5	40	not set	not set	not set
Time settings (seconds)	0	0	0	not set	not set	not set

Table 3-18: Existing voltage relay settings (secondary line-to-line values)

Undervoltage protection settings				Overvoltage protection settings		
Voltage settings	V<	V<<	V<<<	V>	V>>	V>>>
	99	96,8	not set	121	123,2	not set
Time settings	tU<	tU<<	tU<<<	tU>	tU>>	tU>>>
	4 sec	0 sec	not set	1 sec	0 sec	not set

3.10.1 Comments on the settings

The frequency limits do not provide for the steady-state operating limit for the tracking of non-conformances.

The low frequency limit is set below the recommended 49.0 Hz [47] and the emergency limit of 49.5 Hz prescribed by the Lesotho grid code. The existing settings do not consider the maximum frequency settings of 50.5 Hz during steady-state to evaluate the compliance for power quality purposes.

The voltage protection settings are within the generally acceptable limits ranging from 88% to 120%, the trip time delay for overvoltage protection generally ranges from 0.5 s to 2 s.

3.11 Existing frequency and voltage relay scheme at 'Muela generation station

The generators at 'Muela are equipped with frequency and voltage relays for protection against frequency and voltage anomalies. The generators' under-speed protection is set to trip the generators when the speed drops to below 0.9 per unit. Table 3-19 and Table 3-20 provide the existing frequency and voltage relays' settings at Muela hydropower station.

Table 3-19: Schedule of frequency relay settings

Underfrequency protection settings				
Frequency settings	F1	F2	F3	F4
	47,3	46	not set	not set
Time delay (seconds)	T1	T2	T3	T4
	15	10	not set	not set
Overfrequency protection settings				
Frequency settings	F1	F2	F3	F4
	51,5	53	not set	not set
Time delay (seconds)	T1	T2	T3	T4
	60	10	not set	not set

Table 3-20: Schedule of voltage protection relay settings connected to the secondary VT terminals

Undervoltage protection settings		Overvoltage protection settings	
Voltage settings	V<	V>	V>>
	80	120	150
Time delay (t1)(seconds)	1,6	2	0
Time delay of external release (t2)(seconds)	3	not set	not set

3.11.1 Comments on the settings

Both under- / overvoltage settings are within the margins allowed by the manufacturer, the undervoltage settings are, however, outside the $\pm 5\%$ boundaries prescribed by both the Lesotho and South African grid code [48], [50].

The stage 1 underfrequency protection time delay of 10 s exceeds the 1 s provided by the neighbouring SAPP countries [51]. As a result of the hydro units' low turbine speed, the hydro units have low sensitivity to frequency variations [51], [3] which may justify the existing time delays of 15 s and 10 s for the stage 1 and stage 2 underfrequency protection settings respectively. Noteworthy is that the hydro-turbine generators can withstand severe overspeed of up to 200%; this robustness is attributable to their rugged design [3]. In consideration of the recommended settings and considering the behaviour of the hydro generating units during perturbations, these settings are acceptable.

The time delay for activation of overfrequency relay operation exceeds that of the neighbouring SAPP members; 1 s and 4 s for the South African and Namibian grid codes respectively. During the loss of synchronism, it is imperative to separate the systems

operating out of synchronism to avoid further instability escalation and possible damage to equipment [4].

3.12 Testing of the allowable stability limit values

The simulations to evaluate system stability take into account that the Lesotho grid code allows for a maximum fault clearance time of 190 ms [48], while Eskom allows for 120 ms for 132 kV network connections [50]. For replication of the system response to perturbations, the fault occurs at time 0.0 s and the protection operation that includes the breaker opening time occurs at 0.15 s. Through the simulations, the transient stability is evaluated on busbars or transmission lines to test the system robustness during the different fault conditions.

3.12.1 Simulation of system response on a three-phase fault at Tweespruit busbars

Simulation of two cases of a three-phase fault at EMB substation, viz a 120 ms [49] and 190 ms [48] fault clearing time tests the system response to a perturbation. In both cases, the protection time described in 3.12 holds for the simulations. The simulations show the following:

- Voltage magnitude in p.u. at 132 kV busbars for various substations;
- Frequency in Hz at various substations;
- Generators' positive sequence active and reactive power;
- Mechanical torque characteristic, and
- Excitation voltage characteristic response.

3.12.1.1 Analysis of voltage magnitude at various substations' busbars

Voltage instability occurs almost instantly when voltage drops to below 0.9 per unit; the system is stable post fault clearance for both cases (see Figure 3-13).

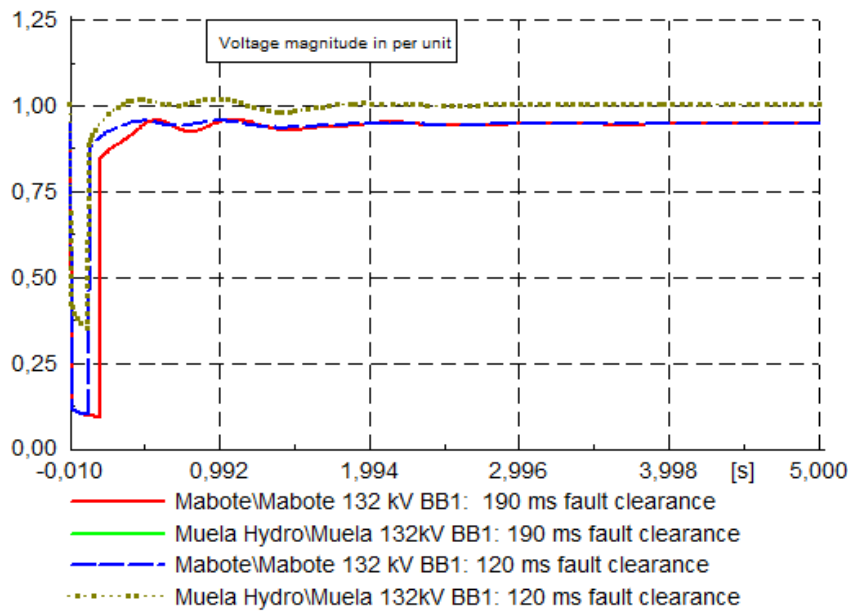


Figure 3-13: Voltage magnitude in p.u. following a three-phase fault at EMB busbars for both fault cases

3.12.1.2 Simulation to duplicate frequency results

The system is frequency stable, the frequency oscillations satisfy stable operating limits even though the fault causes an emergency condition. The system frequency survives frequency instability during this emergency conditions for both a 120 ms and 190 ms fault (see Figure 3-14).

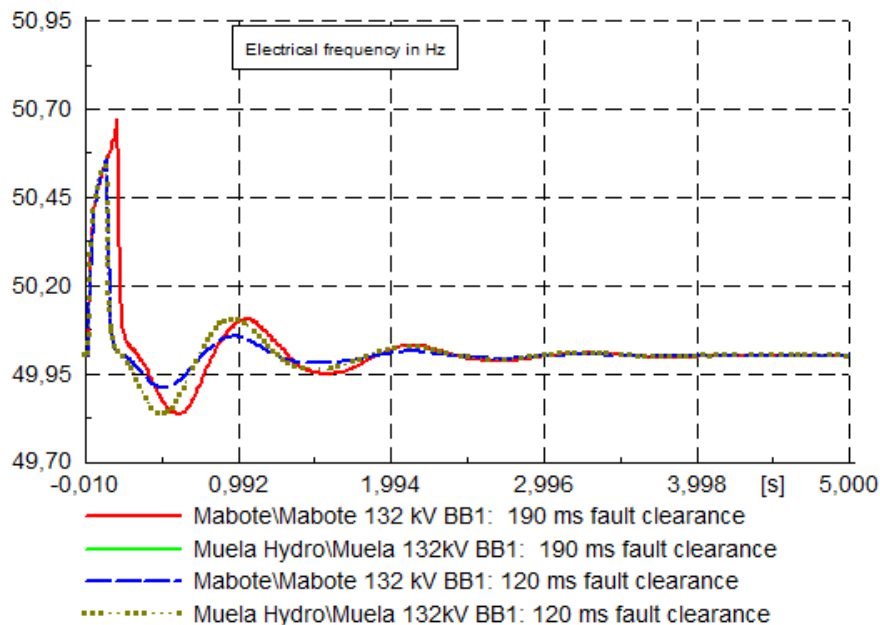


Figure 3-14: Electrical frequency in Hz following a three-phase fault for both fault cases

3.12.1.3 Simulation to represent the generator speed response

The generator speed protection settings at 'Muela' are set at 0.9 per unit; this scheme trips the generators for prolonged generator speed violations. For both fault cases, the generators' speed falls to within stable operating limits post the fault. The oscillations are in direct relation to the fault clearance times, taking into account the relay and breaker operating times, the same holds for governor, active power, and reactive power (see Figure 3-15 to Figure 3-18).

The reactive power injection into the system increases to boost voltage during the fault and decreases post the fault condition to a steady-state. There is suppression of the active power during the fault; high oscillations are successfully damped post the fault and transit into a new stable operating point. The governor opens the gate to aid supply of active power into the system and reduces the flow of water post the fault, as the system transits into a stable operating condition.

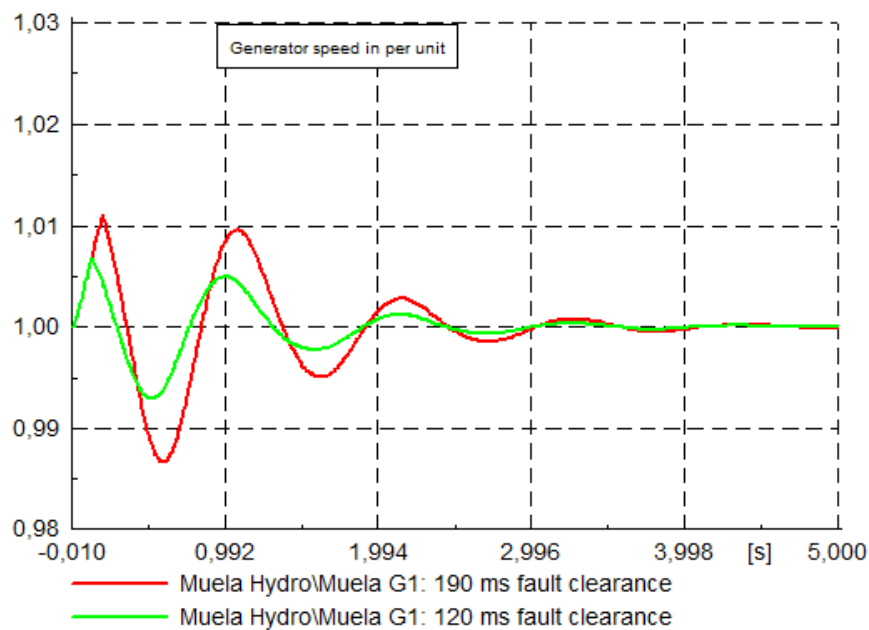


Figure 3-15: Generator speed in p.u. for both fault cases

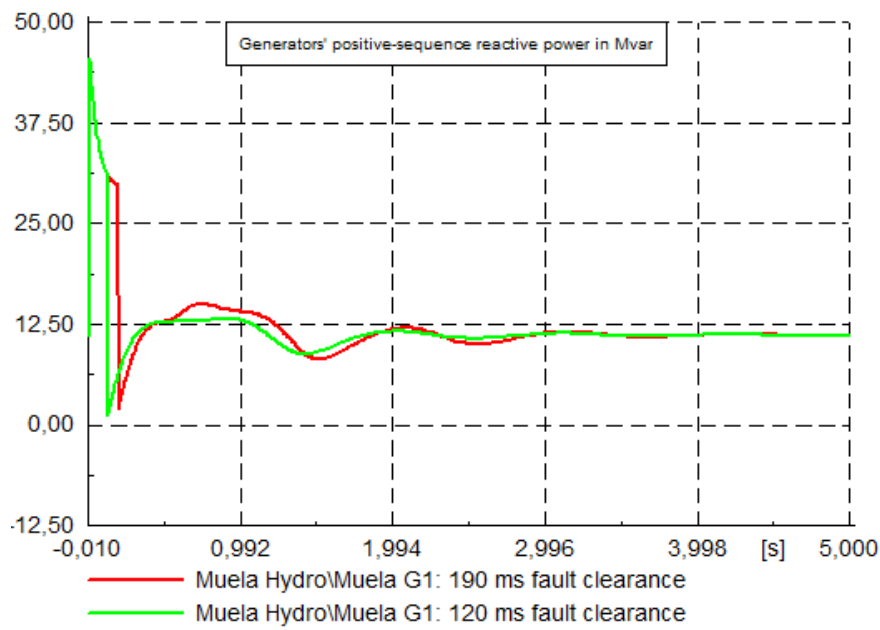


Figure 3-16: Generators' positive-sequence reactive power in Mvar characteristic for both fault cases

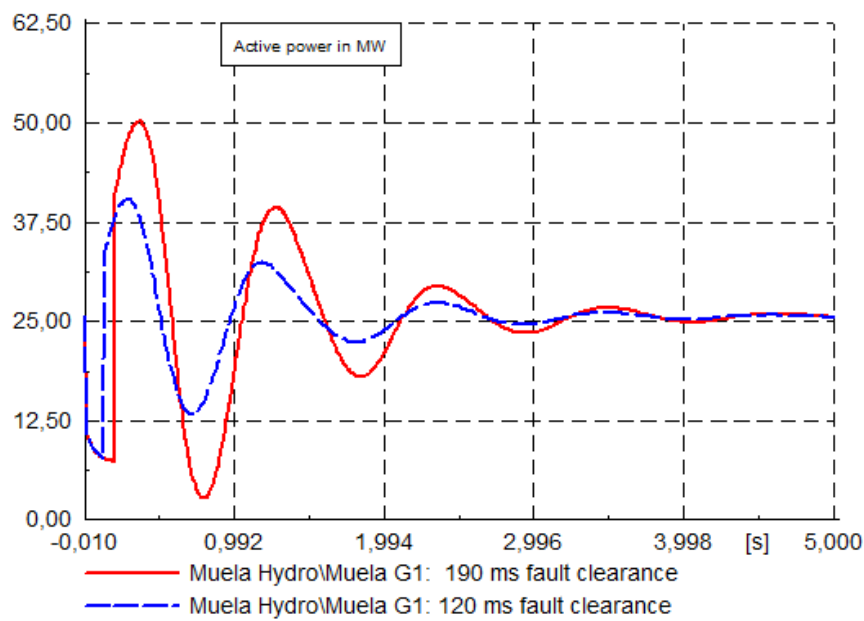


Figure 3-17: Generators' positive-sequence active power (MW) characteristic for both fault cases

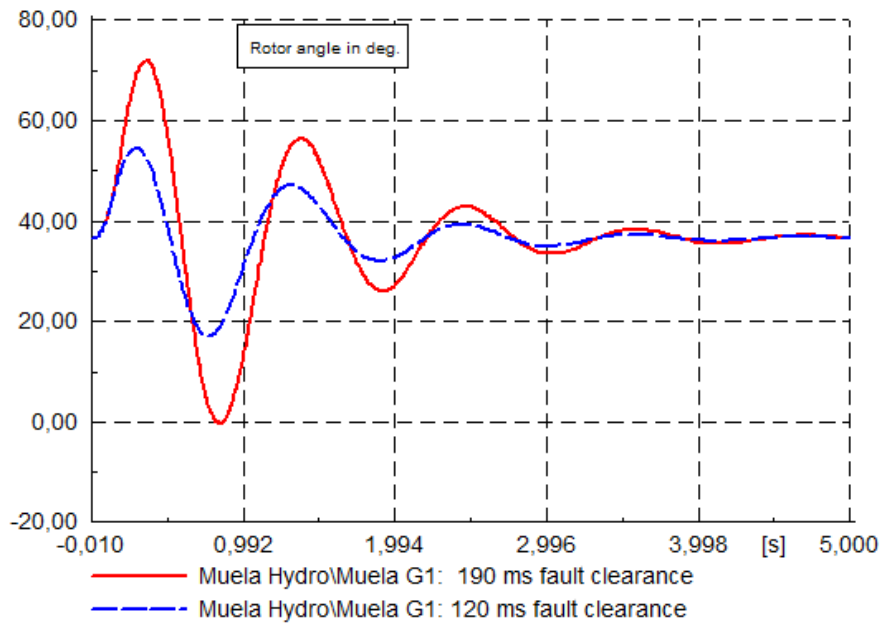


Figure 3-18: The rotor angle with reference to reference bus voltage in degrees for both fault cases

3.12.1.4 Simulation to represent mechanical torque response

Electromagnetic torque opposes the rotation of the rotor and thus impedes the mechanical torque applied by the prime-mover to sustain the generation of active power. For this reason, the reduction in mechanical torque, viz power input, results in a retardation of the rotor position (see Figure 3-19)

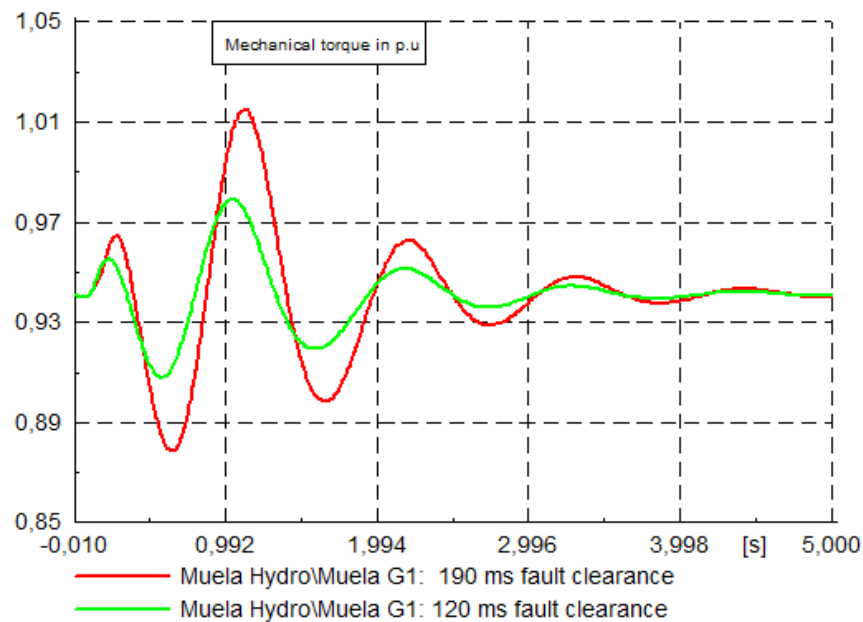


Figure 3-19: Mechanical torque in p.u. for both fault cases

The faster the fault clearance time in the system, the less the system oscillations post the fault, hence the quicker system stable operating conditions are reached.

3.12.1.1 Simulation to represent excitation current response

The excitation current applied boosts the terminal voltage to within the allowable limits, fast excitation system provides fast control of the voltage post the fault clearance in both cases (see Figure 3-20). The limits of the excitation system are set at 10 p.u. current due to saturation of magnetic components [1], hence the system excitation is able to inject up to 3.4 p.u current post the fault.

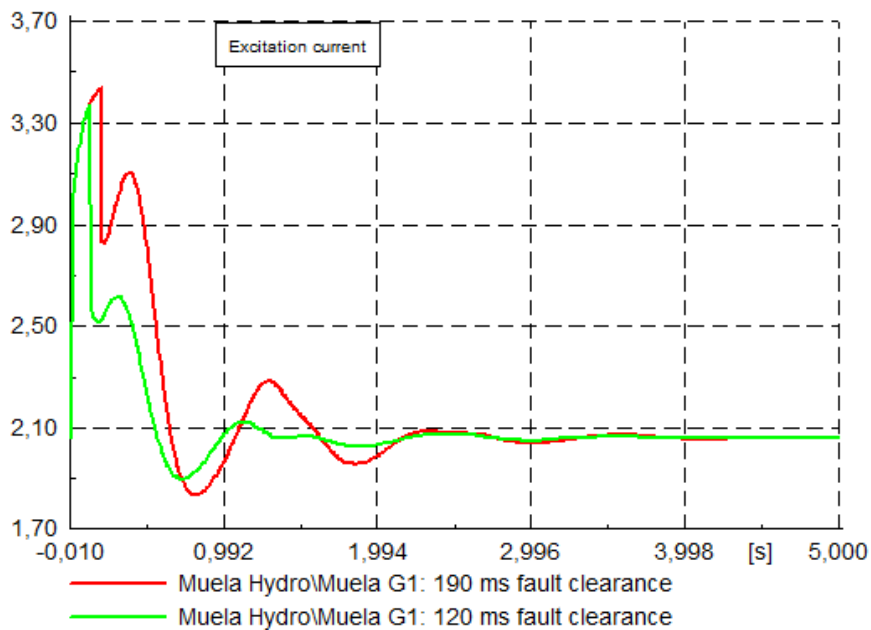


Figure 3-20: Excitation current in p.u. response for both fault cases

3.12.2 Simulating for duplicating 8th May 2016 event

This part of the simulation sketches the scenario of an accidental switch off for a period of 25 seconds aimed at duplicating the event highlighted in 2.10.1. The simulations assume that the event occurred at 0.00 s from the steady-state condition. The analysis covers the following:

- Voltage magnitude in per unit at various substations' busbars;
- Electrical frequency in Hz at various substations;
- Generators' speed characteristic response;
- Excitation system characteristic response, and
- Tie-line reconnection to the system

3.12.2.1 Voltage (132 kV) and frequency characteristics following a tie-line loss

The installed frequency relay settings are 15 s and 10 s for frequency falls below 47.3 Hz and 46.0 Hz respectively; the protection operated much later, only after voltage violations dropped below 0.6 p.u. on other busbars. (see Figure 3-21). The order of system collapse sequence starts with voltage instability and later frequency in the event of a voltage protection failure.

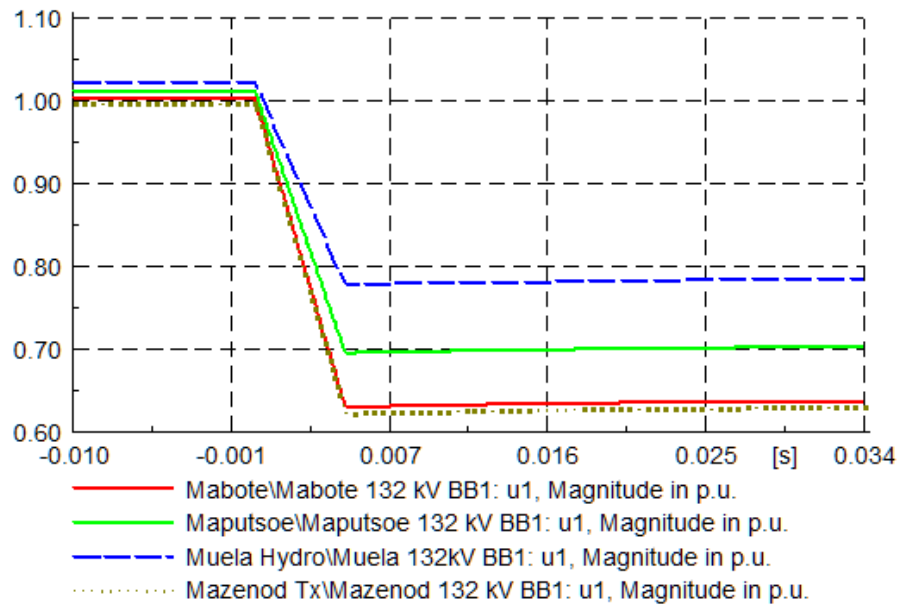


Figure 3-21: Voltage magnitude characteristics during a 25 s tie-line loss

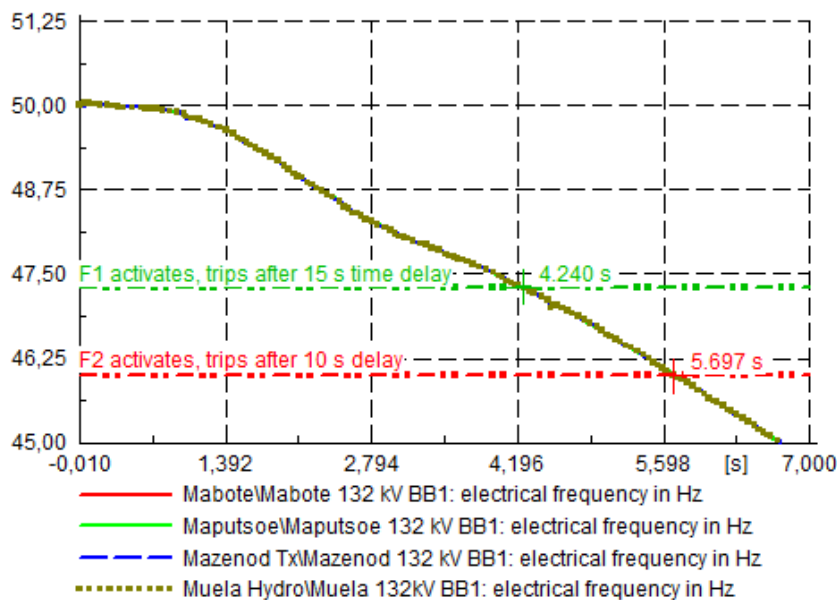


Figure 3-22: Electrical frequency characteristics following a tie-line loss

3.12.2.2 Generators' speed characteristics

The generators' speeds drop sharply to below 0.9 p.u. and thereafter, the generators trip (see Figure 3-23). Assuming the time delay of 1 s, the relay tripped the generators at 7.719 s / 0.88 p.u., much quicker than the set 15 s and 10 s for underfrequency stage 1 and 2 trip respectively.

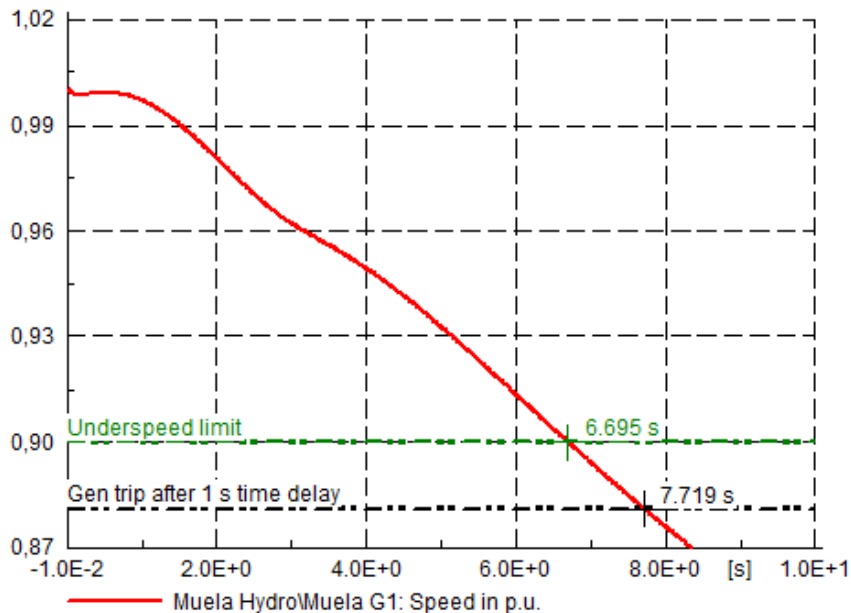


Figure 3-23: Generators' speed characteristics following a tie-line loss incident

3.12.2.3 Protection operation analysis

From Figure 3-21 to Figure 3-23, the generators tripped at 7.717 s on underspeed protection, assuming a 1 s delay from relay activation. The back-up to the underspeed protection is the underfrequency protection tripping at 15.68 s and 19.24 s for stage 2 and 1 respectively. Noteworthy is that the underfrequency protection setting for stage 2 trips at 3.5 s earlier than the stage 1 underfrequency trip setting if the underspeed protection and undervoltage protection schemes fail to operate.

3.12.2.1 Excitation system response

The excitation capability limits control the machine voltage output in the system, thus, they could not achieve voltage stability. Even though the machines applied mechanical torque, the deficit was too large and could not sustain the rotation; which in turn resulted in speed variation.

3.13 Summary

The Lesotho power system relies mainly on imported power for the additional supply of active and reactive power to meet its demand. To maintain system stability, it is crucial to keep frequency and voltage within the acceptable limits to protect the connected equipment as well as the generating plant from mechanical damage. The installed infrastructure undoubtedly has adequate capacity to transmit both active and reactive power. The transmission lines as well as the substations have enough capacity to meet the present and future increase in demand, subject to the increase in imported power or increase in local generation. The management of the supply/demand balance during contingencies is crucial to avoid system collapse in other cases. Implementing automatic load-shedding by disconnecting a proportionate value of loads at the substations that connect directly to Mabote substation for activation of stage 1 load-shedding, can save the system from collapse during faults that affect the tie-line or faults upstream from Tweespruit substation.

The controllers' equipment, e.g. governors, exciters, and power system stabilizers, support the generators to withstand the momentary loss of a tie-line, albeit for a short time. The installed relay configuration allows for monitoring the frequency and voltage status at 132 kV busbars at Mabote substation; they can be more beneficial when configured to activate tripping of the loads in substations that connect to Mabote substation based on the status of the tie-line breaker. In effecting dynamic load-shedding, a thorough study is necessary to categorise the loads in order of their priorities. In doing the load categorisation, the goal should be to alleviate the system collapse with the associated consequences. The communication model between the LEC and LHDA operation personnel, that entails automatic signalling to the generation station for adjustments of reactive power (Mvar), can further improve the chances of success in maintaining the system stability.

The system is frequency and voltage stable post three-phase faults on the tie-line or upstream of EMB substation if faults are cleared within 120 ms and 190 ms, these results satisfy the requirements for both the Lesotho and South African grid code. The model uses the active frequency dependence factor (K_{pf}) and reactive frequency dependency factor (K_{qf}) setting of zero. The model further adopted the active and reactive voltage dependency of load settings of 1.6 and 1.8 respectively.

The system is voltage and frequency unstable in the event of a tie-line loss, where after voltage collapses almost instantly at all 132 kV busbars, while a frequency violation occurs after approximately 200 ms. During the tie-line reconnection to the system, a pole slip occurs making it necessary to conduct an investigation into the cause of the failure to resynchronise. The failure

to successfully resynchronise to the system can cause undesirable catastrophic mechanical stress that may result in the generator rotor damage.

CHAPTER 4 SYSTEM INSTABILITY CAUSES AND MITIGATION MEASURES

Chapter 3 conveyed an overview of the existing frequency and voltage protection installation, the loading profile, and system modelling of the Lesotho power system. The chapter provided an analysis of the existing installation's characteristics, which include the response of synchronous machines controls (AVR, Governor and PSS) during system perturbations such as a tie-lines loss and three-phase faults upstream to EMB substation. It went further to provide simulations of the performance of the existing relays' operation during both the tie-lines loss and the three-phase short-circuit clearing times, considering both the SA and LEWA grid code allowable maximum fault clearance times.

Chapter 4 focuses on the presentation of load-shedding design based on the tie-line circuit breaker status for stage 1 load-shedding; the subsequent load-shedding stages based on the electrical frequency condition (considering the required protection operation), and breaker opening time for load-shedding. The assessment shall consider the following system conditions:

- Options for tripping different loads during tie-line contingencies;
- Evaluation of the system performance during fault conditions;
- Loss of one generator during island operation;
- Evaluation of the SVC impact during the tie-lines contingencies;
- Proposals for power restoration-procedures, and
- Stress management during reconnection of the synchronous machines to the system following the tie-lines loss.

During the system operation, different fault types occur that challenge the transient stability. When the tie-lines trips, various loads should trip through the activation of a dynamic load-shedding scheme. In tripping the loads, the objective is to find the most effective load-shedding scheme that results in a stable system with the least amount of load dropped. The results obtained from study cases 1 to 8 summarise the combination of load dropped at various load-shedding stages in Table 4-1.

Table 4-1: Schedule of different schemes for tripping loads using 150 MW as the base load

Stage	Cumulative value of load-shed per stage							
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8
1	73,17	67,51	64,72	64,72	64,72	52,38	49,15	46,72
2	86,86	88,49	87,75	74,57	74,57	59,48	65,46	76,25
3	93,52	90,55	89,81	89,81	85,36	63,33	72,19	80,25
4	-	-	-	-	89,21	77,85	76,25	-
5	-	-	-	-	-	81,90	80,25	-

In study case 1, tripping 73.17 MW of load resulted in fast system frequency recovery, hence a stable operating condition. This option thus provides fast system overload relieve but affects more customers. Comparatively, in study case 8, tripping 49.15 MW of load did not provide an immediate overload relieve on the system, however, it affected the least number of customers. This chapter shall discuss all these cases, which shall include the merits of each case. The investigation shall culminate in a recommendation of an optimal solution for consideration by the utility.

Finally, the chapter shall establish the critical fault clearing times for three-phase faults on either the Tweespruit substation or on the critical transmission lines. Faults that force the system into dynamic load-shedding shall assume the study case 8 load-shedding scheme. Following successful islanding, the discussion moves on to the requisite conditions for successful resynchronisation after closing the tie-lines to re-join the two systems. The impact that synchronizing in various loading conditions has on the requisite synchronisation limits shall also be assessed.

4.1 Examination of the power system stability model

During loss of the tie-lines, a system's capacity limitations impede the system's ability to transfer enough active and reactive power and it prevents the generators to operate with enough of a spinning reserve margin. Considering the Lesotho power system size, the spinning reserve is not enough to make-up for the deficit when the tie-lines trip. During the simulations to monitor the behaviour of the generating plant during the transient condition, monitoring the variables and generating plots aid in the analysis of the system behaviour during fault conditions. The simulations' output includes monitoring the following dynamic variables in the form of plots to assess the fault impact on the system:

- Active power and reactive power;
- Excitation voltage;
- Rotor angle of the generators;
- Speed of the generators G1 to G3;
- Line-to-line voltage at the substation busbars, and
- Phase currents of generators and the line

The succeeding sections 4.1.1 to 4.1.6 discuss the rationale for monitoring each variable mentioned above.

4.1.1 Active power and reactive power

Monitoring active and reactive power is important, because both have limits within which, if exceeded, they impact negatively on the degree of success to operate the generating units in island mode. Monitoring the output of the generating units helps to avoid unnecessary tripping of the generators due to avoidable factors such as overload and excessive peak active power swings during system resynchronisation, to mention a few.

When the generators produce more active power than required, the system overspeeds and subsequently there is an increase frequency. Both frequency and speed are entangled variables that also need close monitoring for compliance purposes during normal and emergency operation.

The amount of reactive power delivered is important, because the generators do not only provide active power but also produce the reactive power required by the grid when the generators satisfy the lagging reactive power (Mvar) required for voltage control purposes.

4.1.2 Excitation voltage

It is important to monitor each of the installed generators' excitation voltage to assess the level to which the excitation system controlling the field voltage and current keeps terminal voltage constant. Exciters, however, play no role in the output of each generator's active power, but change the amount of reactive power produced for voltage stability purposes.

4.1.3 Rotor angle of the generators and torque

The calculation of a load angle is important, since it determines the amount of torque and the rotor current injection to maintain the terminal voltage constant. An increase in torque results in a higher generator output. The relationship between torque and load angle is that torque increases for an increase in load angle up to 90° , beyond 90° , the torque starts to decrease as the load angle increases, indicating violation of the angle stability limit.

4.1.4 Generator speed and frequency

Monitoring generator speed indicates the balance of the active power generated and the load active power, because the rotating magnetic field of the stator locks onto the rotating magnetic field. The strength of this link is dependent on the field current, thus, an increase in field current results in a stronger magnetic field and vice versa. The speed shall remain within the generators' emergency operating limits.

4.1.5 Line-to-line voltage

With reference to the Lesotho grid code [48], the South African grid code [52] and [50], and the Southern African Power Pool (SAPP) voltage requirements, the set voltage limits for emergency operating conditions are 0.9 p.u. to 1.1 p.u.. This study treats tie-line losses as an emergency condition and applies the voltage limits for an emergency condition. Monitoring voltage limits for violations during the loss of the tie-lines, island mode and prior to re-joining the separate systems to the grid; voltage behaviour thus informs whether the system is voltage stable.

4.1.6 Generator currents and transmission line phase currents

For successful resynchronisation to the system, [53] provides a limit for the peak active power swing as 1.5 p.u.. The peak active power swing is a product of current, voltage and load angle. Allowing the peak power swing to substantially exceed 1.5 p.u. results in unsuccessful resynchronisation, thus, out-of-step condition. One of the driving factors dictating the amplitude of the peak power swing is the resynchronising of the load in the system.

4.2 System load analysis

The amount of power supplied by the generators, considering the geographical location of the hydropower station relative to the load centre, makes it imperative to monitor the voltages on the Muela, Mabote, Lejone and Litsoeneng 132 kV busbars. The Lesotho power system generating capacity is 96 MVA and the grid (Eskom and other connected networks) system capacity is approximately 28 GVA. Considering that the Lesotho power system peak demand is 150 MVA, the faults on the Lesotho transmission system do not cause frequency violations in the network upstream to the fault.

The system perturbations upstream to EMB substation allow longer generators' stability limits than those in the Mabote-Maputsoe transmission lines for the same fault type. For the faults upstream to the EMB substation, the critical fault clearing time (CFCT) is longer due to higher system impedance toward the fault location. The results of the CFCT stem from application of the machine control settings (refer to sections 3.6.3.1 to 3.6.3.3) viz, governor, AVR and PSS, that permit the successful power oscillations dumping after isolating or the fault clearance.

4.3 Initial operating point

In examining the CFCT, the initial operating point is key as it determines whether all the calculated network parameters are fed back to the controllers to fulfil the requirement that all the state variables' derivatives are set at zero. The fulfilment of this condition then permits initialising of the controllers' internal variables. There are various factors that influence the CFCT relative to the generator instability point(s). The effect of an increase in active power of the generator is the fact that the generators get closer to their stability limit. When operating the generators in an underexcited mode, assuming constant output of active power, the effect is an increase of the rotor angle to a larger value that can exceed the stable operating limits. Consequently, for a stability analysis, underexcited generators are more critical than overexcited generators. The generator voltage decreases at a constant active power output and inversely affects the current requirement, resulting in higher voltage drops over the generator impedance; this leads to a larger rotor angle. Adequate measures must be in place when operating generators at lower voltages in a transient state, in order to minimise the risk of loss of synchronism [54].

4.4 Options for tripping different loads during a tie-line loss contingency

The focus is on the impact of the tie-lines loss, the power oscillations which depend on the pre-fault line loading, and the nature of the impact at the occurrence of the fault. When the tie-lines trip, a supply/demand imbalance occurs, which, given the latest loading profile, then dictates dropping of some of the loads to achieve equilibrium. Table 4-2 and Table 4-3 provide requisite considerations to achieve generation/demand equilibrium during a tie-line loss.

Table 4-2: Estimation of supplied optimal load during a tie-line loss**Generation capacity summary**

Gen set output	76,8 MW
Operating reserve	-8 MW
System losses	-4,87 MW
Optimal generation capacity (Tie-line loss)	63,93 MW

Table 4-3: Estimation of total load-shed, including the system losses**Total system load-shed computation**

Total load	150 MW
Less the optimal generation capacity	63,93 MW
Total to be shed	86,07 MW

When the tie-lines trip, the load-shedding relays trip predetermined loads in a designed sequence to limit the impact of the overload on the generation system. Various options of load-shedding different amounts of power are evaluated and the impact of dropping load in each case focuses on the frequency response, active and reactive power, and thermal limits. The triggering time in each case is by design selected to minimise extreme over or underfrequency oscillations during the load-shedding operation.

Referring to Table 4-4, the cases 1 to 8 studies rely on tripping loads that connect directly to Mabote substation for stage 1 load-shedding, viz Mabote, Highway, Tsosane, Mazenod, St Agnes, LEC border, LEC Headquarters and Botsabelo substations. In stage 2, load-shedding trips remote loads such as Litsoeneng, Ramarothole, Ngoajane substations. In stage 3 to 5 the loads tripped are a combination required to satisfy a supply/demand balance. The value of the loads dropped in each case avoids long duration overloads. In all cases, the amount of system overload is limited to 60 s and the time delay is different for each study case. The amount of load dropped to complete the load-shedding procedure in each case satisfies the frequency and voltage limits for operation compliance.

Furthermore, in study cases 1 to 3, stage 3 load-shedding activation occurs to meet the 8.1 MW operating reserve requirement. In Table 4-4, in study cases 4 and 8, stage 3 load-shedding is necessary to meet the supply-demand mismatch. Study cases 5, 6 and 7 require stage 4 and 5 load-shedding to achieve system equilibrium. The analysis of each case considers the fault impact on the generator speed, or electrical frequency (Hz), and the excitation system overload to protect the generation system from overheating. Table 4-4 presents the various options for a load-shedding scheme together with the associated values of load-shed per stage. In all cases, the fault occurs at 100 ms from the start of the steady-state condition.

Table 4-4: Case study 1 - 8 for load-shedding scheme options

Study case #	Stage #	Activation time delays (s)	Load-shed (MW)	Percentage (%)	Total cumulative stage load value (MW)
Case 1	1	0,15	73,17	82%	73,17
	2	0,95	13,69	15%	86,86
	3	10,00	6,66	7%	93,52
	4	-	-	-	-
	5	-	-	-	-
Case 2	1	0,15	67,51	75%	67,51
	2	1,06	20,97	23%	88,49
	3	10,00	2,06	2%	90,55
	4	-	-	-	-
	5	-	-	-	-
Case 3	1	0,15	64,72	72%	64,72
	2	1,01	23,02	26%	87,75
	3	4,47	2,06	2%	89,81
	4	-	-	-	-
	5	-	-	-	-
Case 4	1	0,15	64,72	72%	64,72
	2	7,00	9,85	11%	74,57
	3	8,60	15,24	17%	89,81
	4	-	-	-	-
	5	-	-	-	-
Case 5	1	0,15	64,72	72%	64,72
	2	6,00	9,85	11%	74,57
	3	8,00	10,79	12%	85,36
	4	12,00	3,84	4%	89,21
	5	-	-	-	-
Case 6	1	0,15	52,38	63,84%	52,38
	2	15,00	7,11	9,43%	59,48
	3	20,00	3,84	4,52%	63,33
	4	30,00	14,52	7,00%	77,85
	5	35,00	4,05	5,21%	81,90
Case 7	1	0,15	49,15	54,82%	49,15
	2	19,25	16,30	18,18%	65,46
	3	34,50	6,74	7,51%	72,19
	4	50,00	4,05	4,52%	76,25
	5	58,00	4,01	4,47%	80,25
Case 8	1	0,15	46,72	54,82%	46,72
	2	6,83	29,53	30,21%	76,25
	3	30,00	4,01	4,47%	80,25
	4		-	-	-
	5		-	-	-

The simulations assume that a faulted condition occurred on the EMB-Mabote section of the transmission line; a similar fault on the Tweespruit-EMB transmission line would have a similar impact on the system. The impact of the fault caused a failure on both circuits and forced the

Lesotho power system into island operation. Figure 4-1 depicts the schematic diagram for the portion of the Eskom transmission network for transmitting power to the Mabote substation, with the tie-line breakers open on both transmission line ends of the faulted line. As the breakers open on both ends, they force the Lesotho power system into island operation.

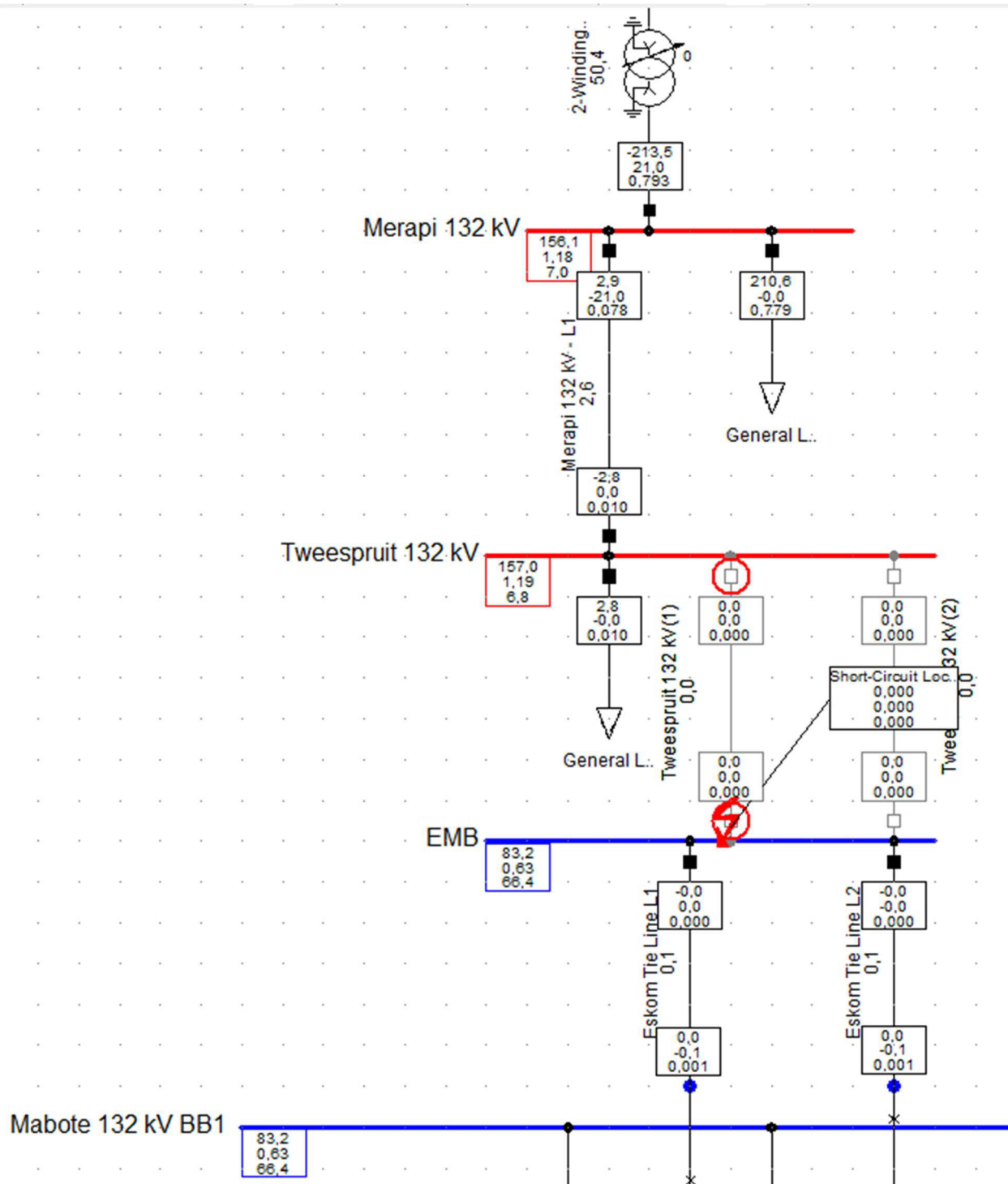


Figure 4-1: Schematic diagram showing the transmission system between the Merapi and Mabote substations

For study cases 1 to 8, the frequency relay installation is on the Mabote 132 kV incomers. The simulations for each study case assume application of the requisite settings in Table 4-4. In all cases, stage 1 load-shedding simulations assume relay communication and auxiliary relay and breaker opening times of 50 ms for each function, thus the total breaker operation time is 150 ms. To avoid a frequency violation and a subsequent system collapse, the protection operates based on the status of the tie-line breaker in stage 1 load-shedding. In the succeeding stages, the relays trip when the frequency falls to below the defined values following a definite time delay for each scheme. The triggers for the activation of fault conditions is the line, busbar faults or human error in switching. The results are divided into two groups for ease of analysis on the loads shed, viz:

- the less severe study cases 1 to 5, and
- severe study cases 6 to 8.

Because of economic considerations, the planning and selection of the shed loads avoid the negative impact on the industrial areas in all cases. The lowest frequency value at which the system can operate in island and during dynamic load-shedding transition before tripping on frequency violations is 47.5 Hz [50]. Below this value system frequency stability is unlikely. In consideration of the foregoing, in study cases 1 to 5, the frequency falls to 48.50 Hz. On the contrary, in study cases 6 to 8, the lowest frequency is 47.0 Hz, a value that exposes the system to the risk of frequency collapse. The Lesotho grid code does not specify the different limits for frequency drop during emergency conditions.

4.4.1 Results of study cases 1 to 5

With reference to Table 4-4, study cases 1 to 5 review the impact of the tripping of a combination of loads at various substations to achieve system equilibrium (see schedule of loads tripped in Annexure 3 -1). The amount of load dropped for stage 1 per scheme varied from 73.17 MW to 64.72 MW. The activation of all the load-shedding stages occurred within 12.0 s in all the cases. The system was frequency and voltage stable, there were no reactive power violations and the generators' speed was within the ± 10 % limits (see Figure 4-2 to Figure 4-4).

The advantage of these schemes is the minimal thermal impact on the generators as relatively low currents were present in the stator and rotor windings during the switching. One of the drawbacks associated with these load-shedding schemes is that it affects more customers negatively. If the tie-lines fail when the system load is low, an unnecessary high number of customers are affected as more stations are tripped and this raises the consequences of that disturbance. This inconvenience can be addressed by using a dynamic load-shedding relay that drops the load amount to less than 80 MW irrespective of the pre-fault load condition. The activation of stage 2 load-shedding stabilizes the system frequency and active power

operating limits. Because study cases 1 to 5 did not provide an optimal solution to the problem, it was necessary investigate additional study cases 6 to 8 for alternative solutions.

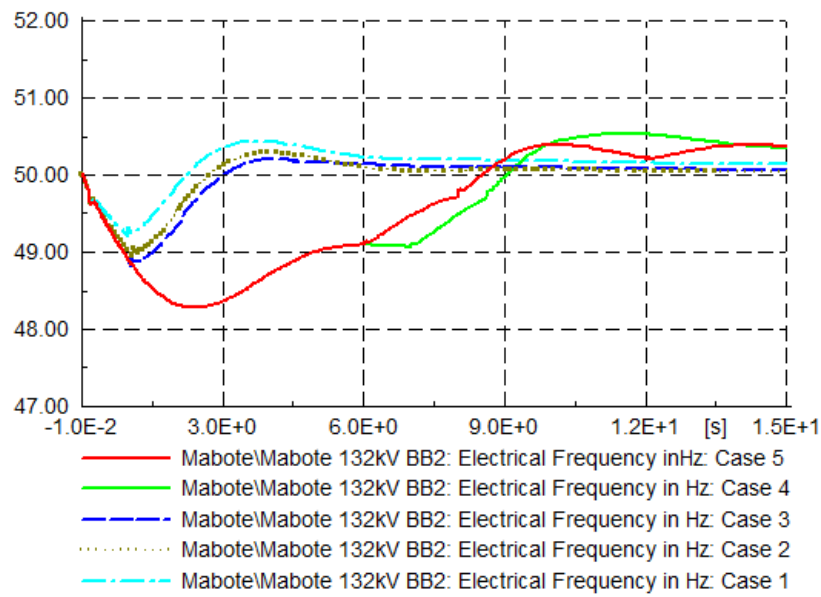


Figure 4-2: Frequency in Hz for load-shedding study cases 1 to 5

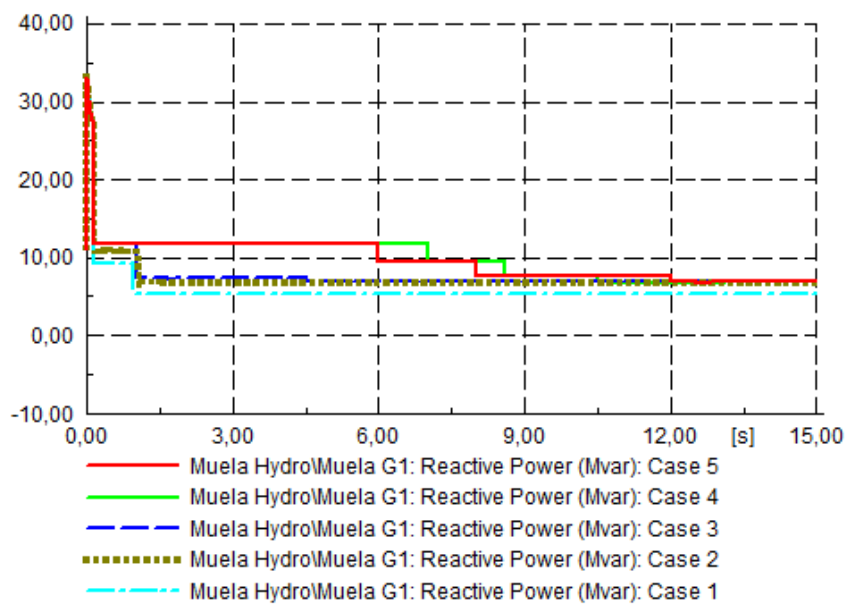


Figure 4-3: Reactive power (Mvar) for load-shedding cases 1 – 5

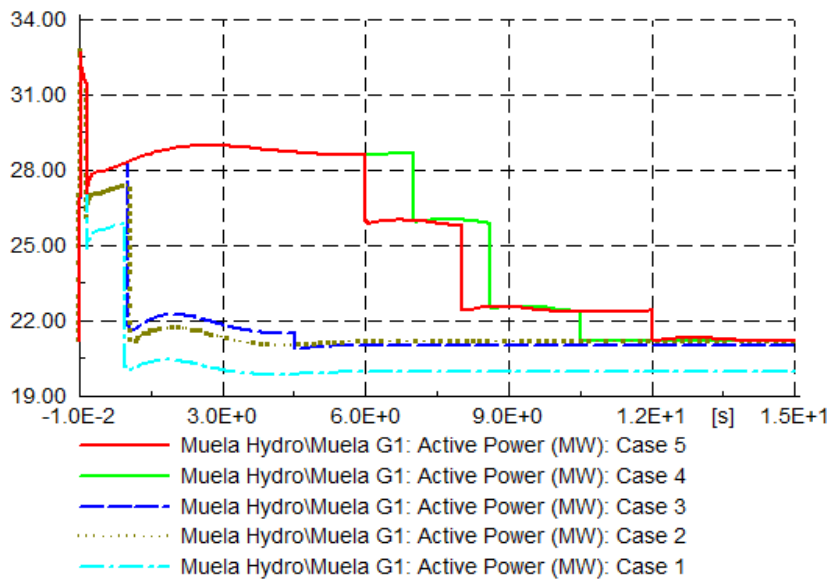


Figure 4-4: Comparison of active power (MW) generation for study cases 1 to 5

4.4.2 Results of study cases 6 to 8

The aim of the simulations was to establish the maximum limits at which the system could operate without causing a system collapse following a frequency or voltage violation. In study cases 6 to 8 the protection system shed smaller blocks of loads ranging from 52.38 MW to 46.72 MW for stage 1 load-shedding based on the status of the tie-line breaker (see schedule of loads tripped in Annexure 3-2). Since the system was operating in an emergency condition, the lower limit for system voltage compliance was determined at 0.90 p.u, the frequency minimum limit was 48.5 Hz and the maximum limit was 51.0 Hz. The grid code allows for generating units to withstand momentary frequency excursions outside the boundaries of 48.5 Hz and 51.5 Hz [48] and [50].

Stage 2 and the succeeding load-shedding stages allowed for a time delay of 6.68 s up to 58 s. In Figure 4-7 and Figure 4-8, shedding too little load (refer to study cases 7 and 8) resulted in a frequency drop to 47.0 Hz. Voltage recovery was faster for study case 8 because of the large block of load tripped (29.53 MW) versus cases 6 and 7 in which the tripped blocks were 7.11 MW and 16.3 MW for stage 2 respectively.

In study case 6, the simulations showed that the lowest frequency drop was to 48.01 Hz, therefore stage 2 load-shedding was activated after a 15 s time delay and the frequency recovery did not violate the underfrequency limits for a frequency drop to below 48.5 Hz and 48.2 Hz.

In study case 7, the simulations show that frequency dropped to 47.0 Hz, thus stage 2 load-shedding was activated after 19.1 s, a much slower activation time compared to study case

6. The drawback in study case 7 was that frequency recovery took longer and it violated some of the frequency drop provisions ($F=47.9$ Hz, $t<18.59$ s and $F=47.5$ Hz, $t<13.43$ s). These results however satisfied the 1 minute allowed recovery time for both the frequency drop to below 48.5 Hz and 48.2 Hz [50]. The implementation of study case 7 is less preferable because of prolonged frequency violations.

In study case 8 there was a sharp frequency drop to 47.0 Hz, stage 2 load-shedding was activated after 6.68 s and the frequency drop satisfied the provision in [50] for frequency recovery for 48.5 Hz to 47.5 Hz, but violated the provisions for frequency drop to below 47.0 Hz ($t<0.221$ s). The generating units recovered successfully upon application of stage 2 load-shedding. The SA grid code allows for a generator trip after 1 s for a frequency drop to below 46.0 Hz, for this reason, the frequency drop did not cause the generators to trip as it did not reach this threshold. The Lesotho power system stakeholders can use this option as the worst case scenario and still achieve optimal frequency recovery following the tie-lines loss.

Considering study case 8, if load-shedding stages 1 and 2 fail, frequency drops to 45.05 Hz a second after crossing the 46.0 Hz limit, whereas if stage 1 succeeds and stages 2 and 3 fail, the frequency drops to 45.85 Hz a second after the frequency decline to below the 46.0 Hz limit. The Lesotho power system can barely survive the frequency decline to below 46.0 Hz and recover successfully if enough load is dropped. However, permitting the decline to below this limit exposes the system to the risk of collapse. The generators would trip if low frequency duration below 46.0 Hz exceeds 1 s to protect the generating system. Permitting the frequency drop to below 46.0 Hz increases the risk of loss of the security of supply. The recommendation is that the LEC and LHDA adopt the study case 8 scheme, because of the comparatively higher conformance to the SA grid code requirements and the advantage of affecting a minimum amount of customers on activation of stage 1 load-shedding.

In study cases 6 to 8, reactive power was not a concern, the active power required activation of all stages to meet the operational limits for all the study cases. Figure 4-5 indicates that the system is also voltage stable for study cases 6 to 8 after execution of stage 1 and 2 / 3 load-shedding to arrest frequency decline.

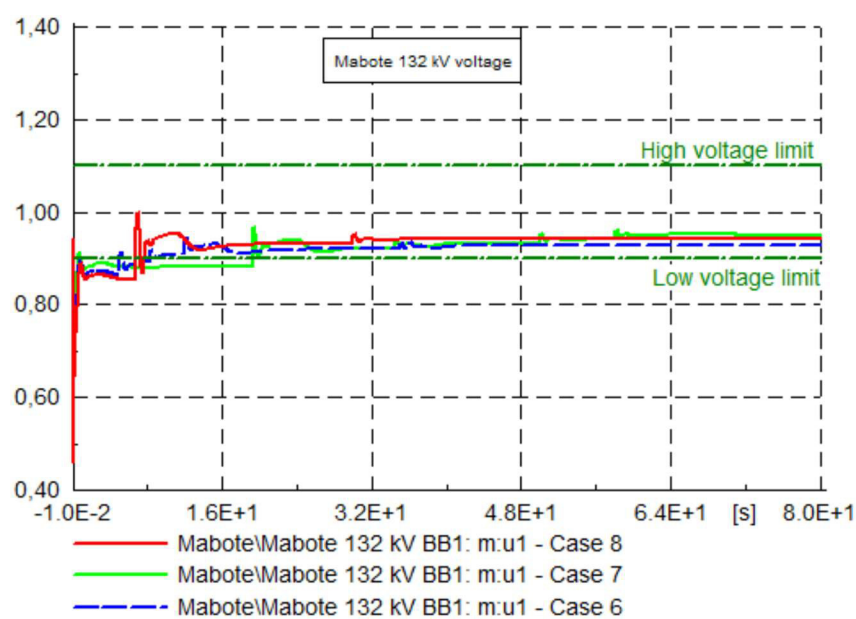


Figure 4-5: Comparison of busbar voltage in per unit at Mabote substation for study cases 6 to 8

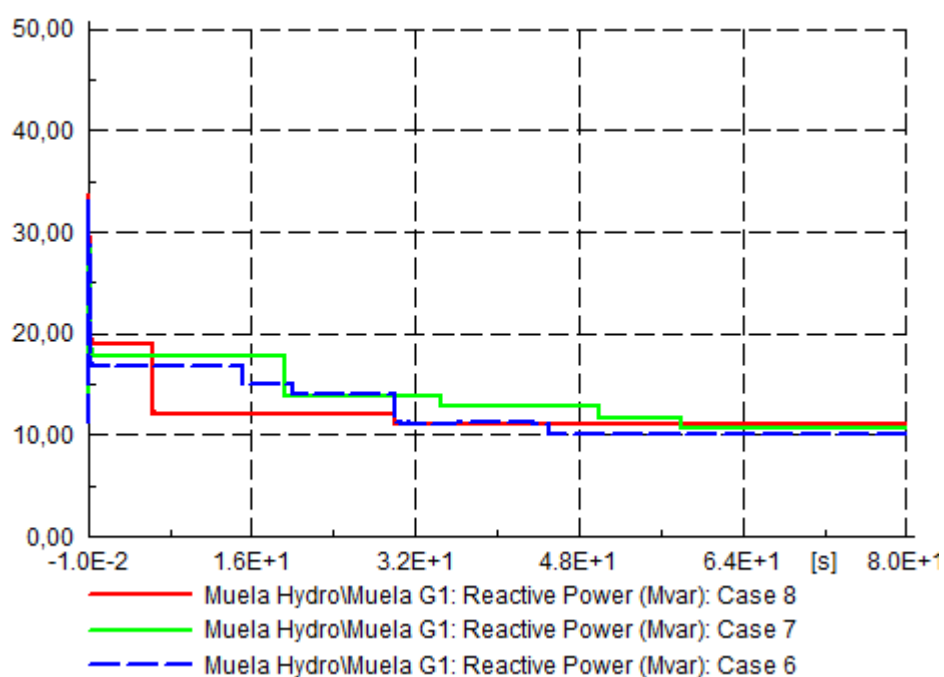


Figure 4-6: Comparison of reactive power (Mvar) demand on the hydro generators for study cases 6 to 8

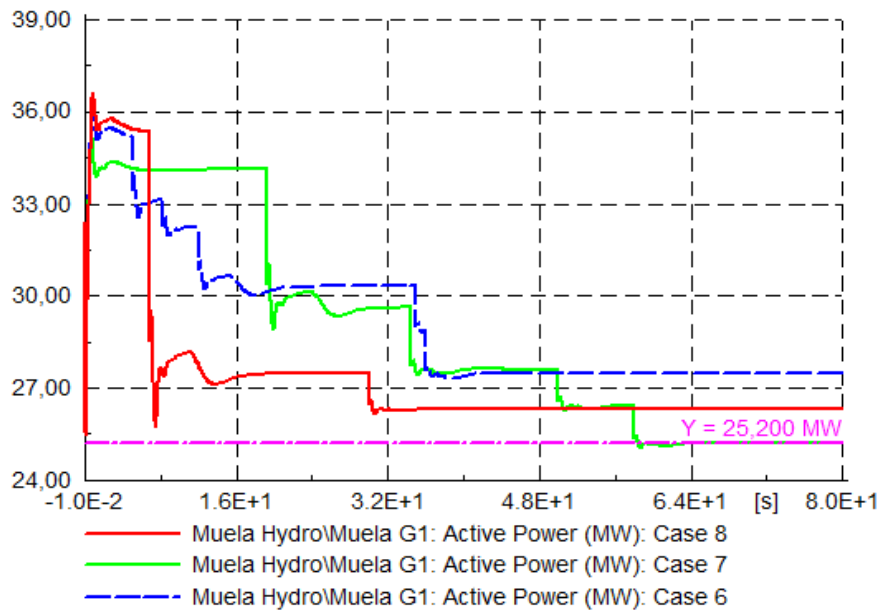


Figure 4-7: Comparison of active power (MW) demand on the hydro generators for study cases 6 to 8

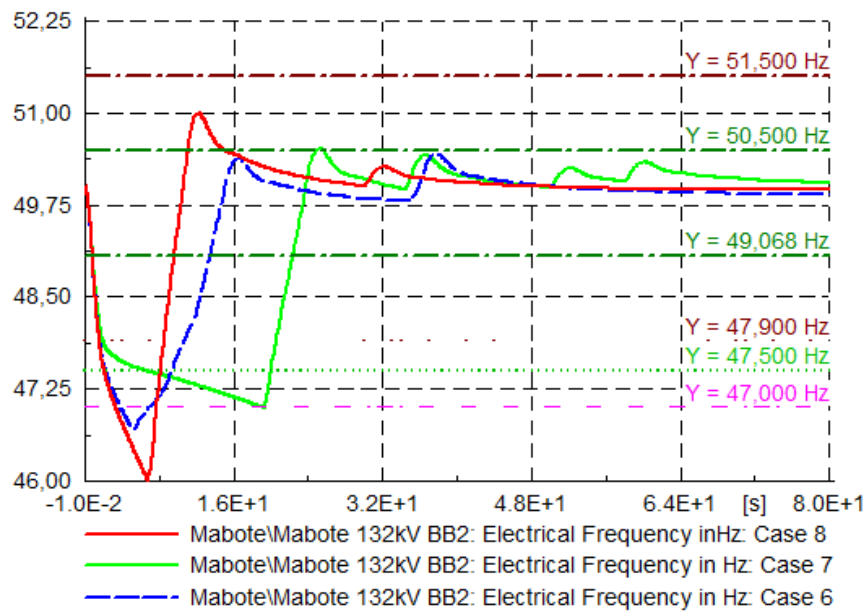


Figure 4-8: Comparison of frequency in Hz for study cases 6 to 8

4.5 Transient stability assessment for faults upstream to EMB substation

In analysing the transient stability of the system, it is paramount to establish the CFCT, which focuses on the maximum duration of a short-circuit at a given power flow when no pole-slipping of generators occur [55]. The CFCT determine whether the system successfully maintained the transient stability with a continuous stable operation when a three-phase fault is removed from the system. The process of obtaining transient stability entails simulations to determine the

system response under faulted conditions. These simulations use the CFCT technique, which uses an iterative process [12].

The simulations in this section determined the impact of faults both upstream to EMB substation (towards Eskom) and those that occur on the Mabote-Maputsoe 132 kV line. The discussion covers the impact of sudden transient disturbances at the fault points in which a large momentary swing, relative to the rotating magnetic field, can cause loss of synchronism. The key characteristic in ensuring stability of the system post the fault is determined by the critical clearing time of a fault [6]; a shorter fault clearing time results in a stable system and vice versa. The limit and application of transient stability is determined by the nature of the fault. The faults occurred at the following locations:

- Three-phase busbar fault at Tweespruit substation - no load-shedding following protection operation;
- Three-phase faults occurring at Tweespruit 132 kV busbars- followed by dynamic load-shedding;
- Line faults on Tweespruit – Mabote 132 kV line transmission line, and
- Generator trip events during island operation.

In three-phase disturbances, the faults that have the largest impact are those whose duration causes a significant suppression in the machine terminal voltage and that impede the systems' ability to transfer synchronising power. During the transient faults, and when fault duration exceeds the CFCT, the generators lose synchronism with the power network because of disturbances on either the transmission line or busbars. The result of the loss of synchronism is rapid rotor oscillations as well as oscillations in current, voltage and power factor as the oscillations go beyond stable limits.

The critical clearing time depends on various factors, such as generator inertia, type of disturbance, its location, and its duration [1]. The contributing factors for the transmission lines are line impedance, fault type, location of fault, etc. To achieve system stability through the variation of the fault clearing time, the clearing time value should be less than the critical clearing time [16]. The consequences of exceeding the critical fault clearing time include loss of synchronism leading to a system collapse. Equation 4-1 [16] presents the time difference between the critical clearing time and the actual clearing time used to compute the transient stability margin, the actual clearing time is derived from the solution of a swing equation.

$$K_{time} = \frac{(t_{cr} - t_f)}{t_{cr}} \quad (4-1)$$

Where

t_{cr} is critical clearing time

t_f is actual clearing time

K_{time} is the transient stability margin

Fault(s) occur and then they are cleared by tripping breaker(s) after a defined time. Equation 4-2 [6] determines the establishment of the system stability as well as the computation of the critical clearing angle.

$$\delta_c = \cos^{-1} \left\{ \left[\frac{1}{r_1 - r_2} \right] \left[\left(\frac{P_m}{P_M} \right) (\delta_m - \delta_0) \right] + r_2 \cos \delta_m - r_1 \cos \delta_0 \right\} \quad (4-2)$$

Where

δ_c – critical clearing angle in degrees

P_M – peak pre-fault power angle curve

r_1 – peak of power angle curve ratio of the faulted circuit to P_M

r_2 - peak of power angle curve ratio to P_M with fault cleared

$$\delta_0 = \sin^{-1} \left(\frac{P_m}{P_M} \right) < \frac{\pi}{2}$$

$$\delta_m = \sin^{-1} \left(\frac{P_m}{r_2 \times P_M} \right) > \frac{\pi}{2}$$

4.5.1 Three-phase fault at Tweespruit substation – with automatic load-shedding

The two transmission lines between Tweespruit and EMB substations are approximately 53 km long with a single bear phase conductor per circuit. The faults that affect these lines subsequently affect the supply-demand balance on the Lesotho transmission system resulting in a power deficit of more than 70 MVA if the fault trips the tie-lines.

A three-phase fault condition was applied to Tweespruit substation, this fault caused both lines 1 and 2 to trip at Tweespruit and afterward, a time delay trip at Mabote substation to isolate the fault (refer to Figure 4-1 for schematic diagram on this part of transmission network). Stage 1 load-shedding was activated when the tie-line breakers opened at Mabote and thus, it isolated the tie-lines.

Considering the system characteristics when subjected to various load-shedding study cases, study case 8 portrayed the system response under extreme conditions (refer to Table 4-5,

section 4.4.1 and 4.4.2). Considering study case 8 as a preferred scheme for implementation, Table 4-5 presents the amounts of loads dropped per load-shedding stage and the protection settings applied to achieve successful islanding with the least number of customers affected.

Table 4-5: The protection scheme for load-shedding study case 8 during a three-phase fault at Tweespruit.

Study case #	Stage #	Delays (s)	Load-shed (MW)	Percentage (%)	Total cumulative stage load value (MW)
Case 8	1	1,14	46,72	54,82%	46,72
	2	6,44	29,53	30,21%	76,25
	3	41,44	4,01	4,47%	80,25
		-	-	-	-
		-	-	-	-

The simulations show that the system was voltage stable after implementing stage 2 load-shedding, thus, the system satisfied the provisions for emergency operation (see Figure 4-9 and Figure 4-10). The monitored key variable was the maximum rotor angle deviation, which provided an indication of the status of the synchronous operation of the generators. The computations using DIgSILENT showed a change in rotor angle from 28.5° to 42.2° with reference to bus voltage; this maximum rotor angle oscillation did not cause the generators to lose synchronism (see Figure 4-11).

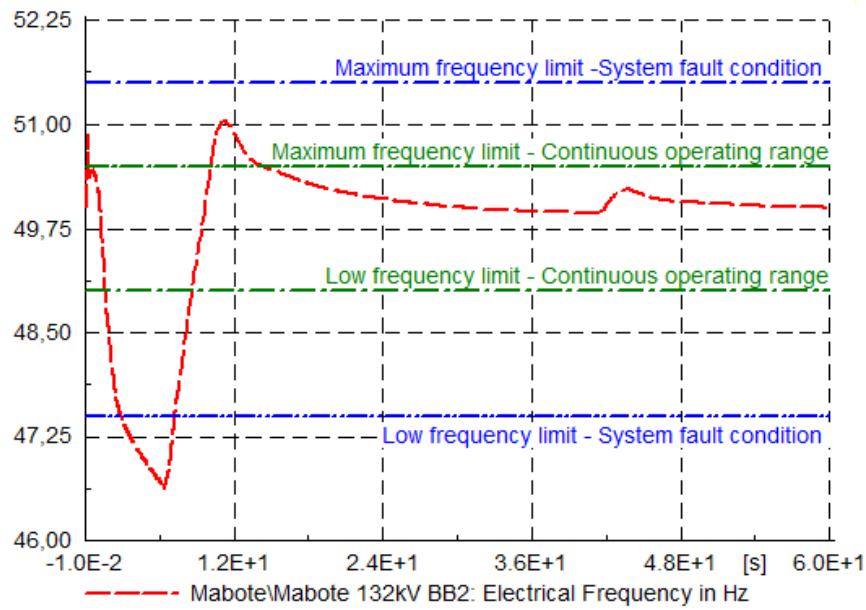


Figure 4-9: Frequency in Hz during a three-phase busbar fault on Tweespruit substation

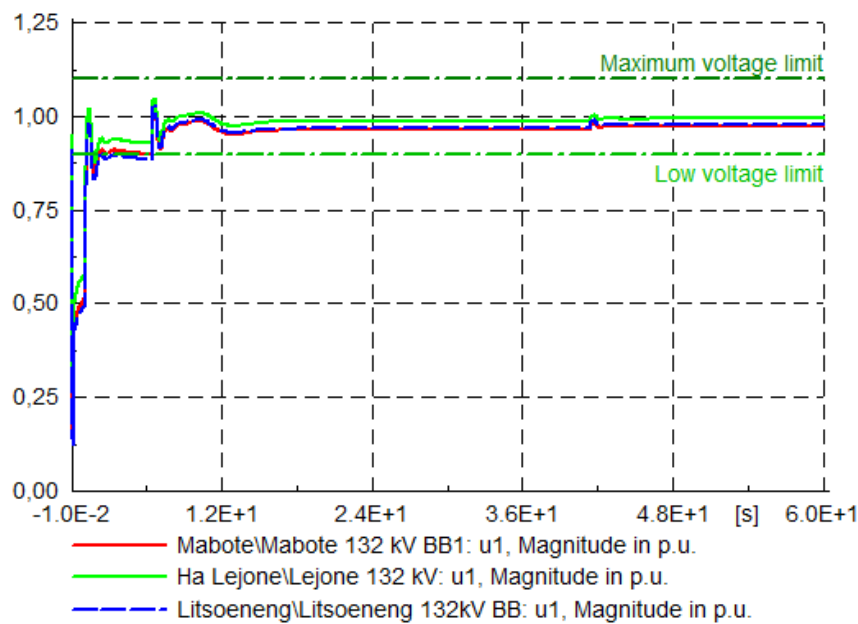


Figure 4-10: The voltage in per unit during a three-phase busbar fault on Tweespruit substation

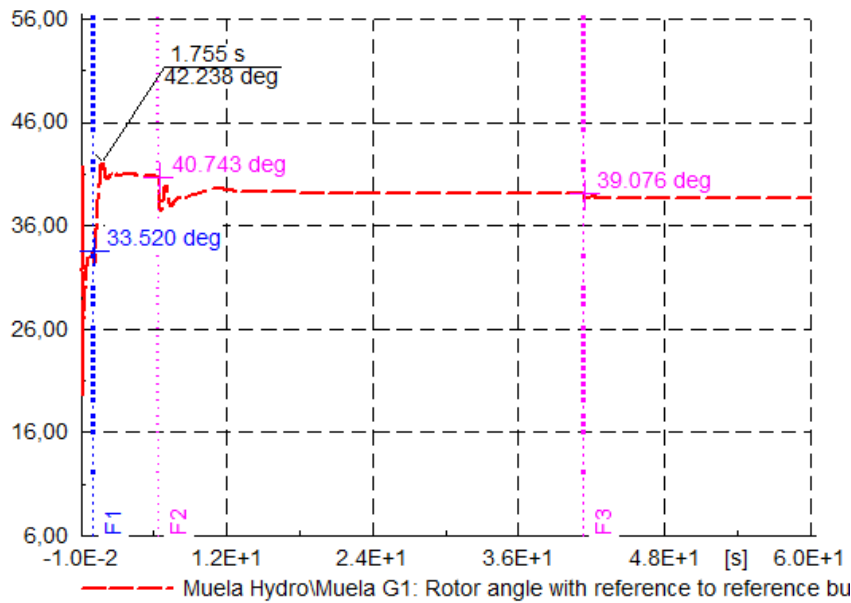


Figure 4-11: The rotor angle with reference to the reference bus voltage in degrees during a faulted condition on Tweespruit substation

During the three-phase fault, the basis for evaluation was to determine whether the system reached a permissible steady-state condition post the fault. The fault affected the power balance within the Lesotho power system, thus, the longer it took to clear the fault, the more changes were caused on the equivalent network impedance [10] and the longer it took to reach a stable state condition or even a pole-slip condition. The system's response to a three-phase fault involved large excursions affecting the generator rotor angle due to nonlinearity of the power angle relationship.

During the dynamic process, the stator and rotor currents increased due to a sudden increase in load on the generating units caused by a fault. Using the recommended IEEE [56] operating limits as a guide, the simulations' outputs were compared with the recommended operating limits and a graph comparing the two cases, was plotted. Figure 4-12 shows that during the transient period, the measured excitation current fell within the provided limits, thus, the application of load-shedding as per study case 8 did not harmfully affect the generators' operating limits. Tripping approximately 46.72 MW during stage 1 load-shedding as well as during the subsequent load-shedding stages in the same scheme, guaranteed system stability during tie-line failures.

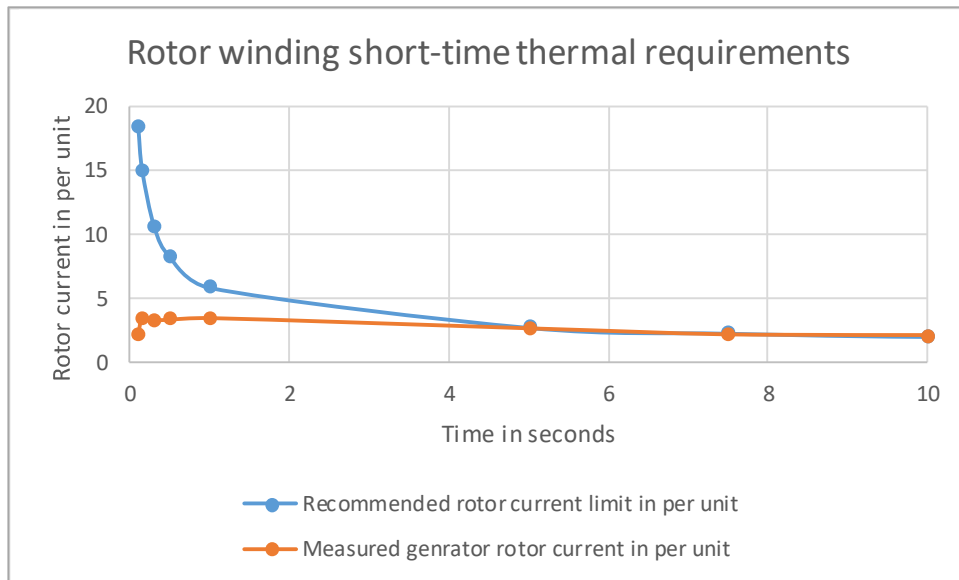


Figure 4-12: Comparison of the measured excitation current versus IEEE recommended limits

In the existing status the system collapses on voltage and frequency instability when the tie-line fails. The simulations in study cases 1 to 8 show that the status quo can change by the application of dynamic load-shedding using any of the proposed schemes in this study.

4.5.2 Line faults on Tweespruit-Mabote and Mabote-Maputsoe transmission lines

This section discusses the ability of the system to successfully maintain synchronism during and after the clearance of a severe line fault. The focus is on determining the CFCT during various system perturbations. The CFCT is crucial for the nodes that are critical for maintaining synchronism in the Mabote substation and the upstream network. The faults were of single- and three-phase nature and were applied at different locations between critical lines transmitting power at Tweespruit and Mabote substations. The selected scenarios were:

- The three-phase line fault on line 1 when line 2 was healthy and in-service;
- Three-phase line fault on line 1 when line 2 was out-of-service, and
- Single-phase-to-ground line fault on line 1 when line 2 was in-service, fault was cleared in normal protection time of 1 s.

The analysis of each study case included examination of the rotor behaviour and the impact on stability emanating from the non-linear angle relationship during the fault condition. The testing of the CFCT and the conclusion reached by the simulations in each case aid the establishment of the stability limits for different fault types. The value of the critical clearing time therefore provides a reflection of the longest time for which the generator will remain in synchronism during and after the disturbance.

The procedure for testing the contingencies was:

- A fault application occurs on the line in the range of 10% to 90% of each line length at 100 ms;
- The line tripped at the substations at varying times until it reached and or exceeded the CFCT;
- The line tripped at node-j (j- denoting the other end of the faulted line) because of inter-trip activation;
- Calculation of the values for critical clearing times and the critical clearing angle for both cases, and
- Identifying the system elements that were unstable.

4.5.2.1 Three-phase Line faults on line 1 when line 2 was in-service

The transmission system connecting Mabote substation to Muela hydropower comprises of a double circuit using a bear overhead conductor. With reference to Table 3-10, each circuit has a surge impedance loading (SIL) of 46 MW, the SIL being the loading on the line where the net reactive power is zero translating into the limit of the maximum power that each circuit can transfer at 132 kV.

Generally, when a three-phase fault occurs on a transmission line, the nearest breaker trips to clear the fault and the breaker on the other end of the transmission line trips after a defined time delay on inter-tripping. The execution of the simulations adopts the inter-tripping concept for purposes of demonstrating the transmission line behaviour during faulted conditions.

The objective of the test for the CFCT was to establish the limits within which the system was able to recover when confronted with a three-phase fault on this part of the transmission system. The same scenario was valid for the faults on the Mabote-Maputsoe transmission line. The simulations assumed a fault clearance at the Tweespruit line through the operation of zone 2 protection set at 0.50 s. Zone 1 protection clears the faults on the transmission line between EMB and Mabote substations after zero time delay.

In Figure 4-13, the fault was applied on either the Tweespruit-EMB, EMB-Mabote or Mabote-Maputsoe circuit 1 when circuit 2 was in-service. In each case, the transient stability was tested on each transmission line individually and was based on the fault location. The fault was applied at different line locations, e.g. in Figure 4-14, a faulted condition was applied at 10% of the EMB-Tweespruit transmission line, the breakers tripped on both ends of the faulted line. The results were plotted, showing the relationship

between the CFCT and the fault location on the transmission line to determine the system transient stability limit.

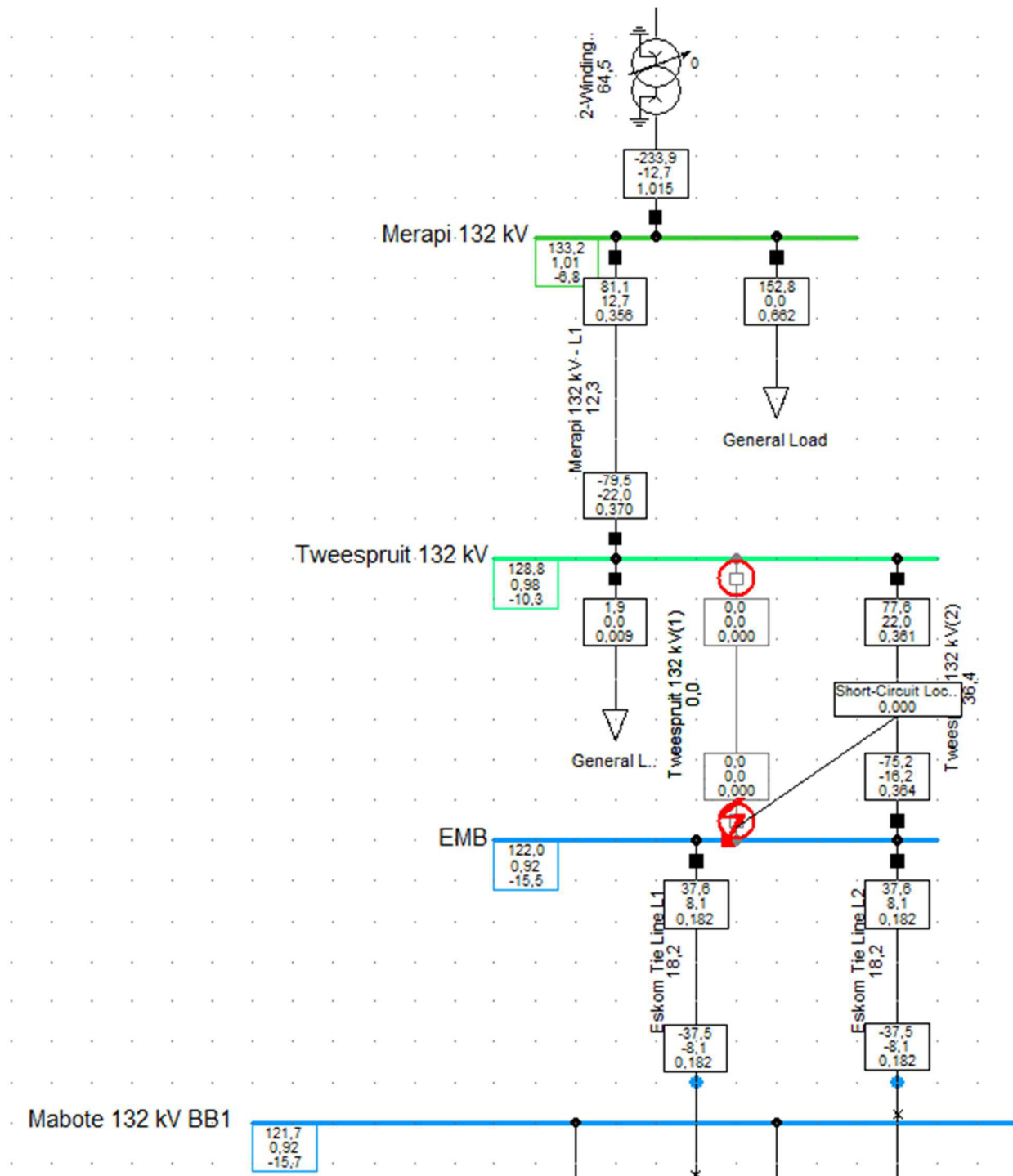


Figure 4-13: Schematic diagram showing the fault on the transmission system between EMB and Tweespruit substations

The simulations for critical clearing time indicated a direct relation to the distance from the source. The fault locations in percentiles for testing stability were the sending nodes of the busbars (read from the grid (Eskom) supply side). The critical lines for the transmission of power are the Tweespruit-Mabote transmission lines. The existing distance protection for

Mabote-EMB relay operating time delay is set at zero and 0.5 s for zone 1 and 2 respectively. These existing settings when read together with the CFCT for various locations indicate a severe contingency, because the CFCT is smaller than the actual settings for the breaker to safely trip the line.

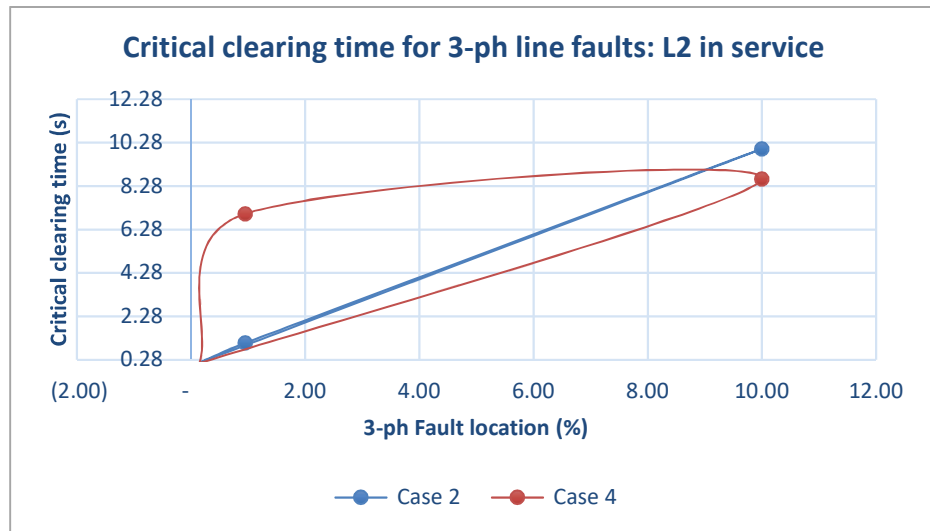


Figure 4-14: Critical fault clearing time during the three-phase faults on circuit 1 when circuit 2 was in-service

From Figure 4-14, the existing settings are beyond the CFCT to permit system stability post a three-phase fault on the Tweespruit-EMB line when circuit 2 is in-service.

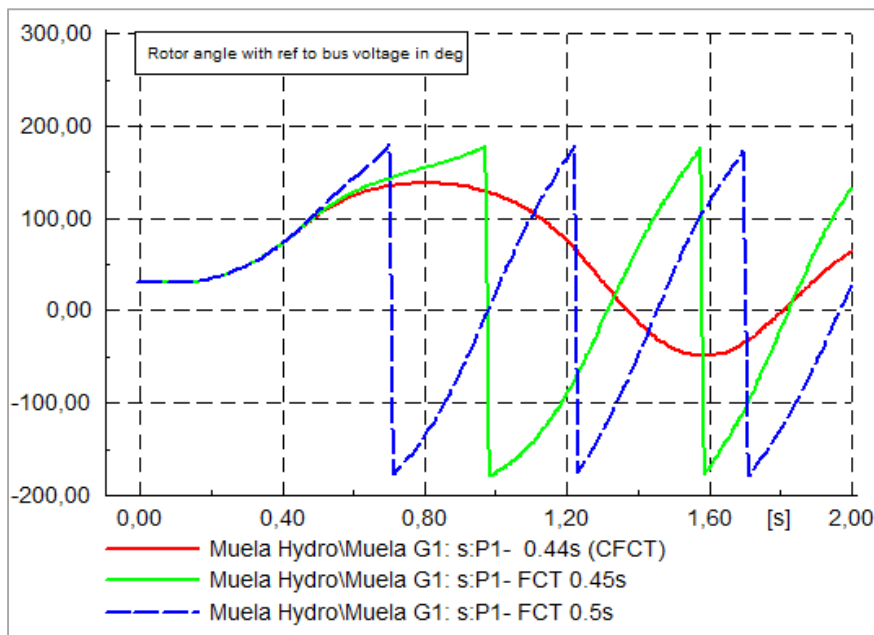


Figure 4-15: Rotor angle response to different fault clearing times for a fault on the Tweespruit line

As a preventative measure, it is good practise to make the CFCT longer than the breaker operating time. The fault clearance requires opening of the breakers before reaching the CFCT and critical fault-clearing angle to maintain system stability.

The test for transient stability depicted in Figure 4-15 shows a faulted condition applied at 10% of the Tweespruit-EBM transmission lines at 0.1 s. The results show that a system transient stability limit was reached at 0.44 s and the system was unstable for a clearing time longer than the CFCT, e.g. 0.5 s. Further details on the system response are provided in Annexure 4-1.

4.5.2.2 Three-phase line fault on line 1, line 2 out-of-service

Considering a faulted condition scenario on line 1 when line 2 is out of service, tripping line 1 to clear the fault creates island condition. The tests were performed on both the Tweespruit-EMB and Mabote-Maputsoe transmission lines; each line was tested independently and for different fault locations. Figure 4-16 presents the results for the CFCT at different transmission lines' locations for a scenario where line 2 was out-of-service for both the Tweespruit-EMB and Mabote-Maputsoe faulted conditions.

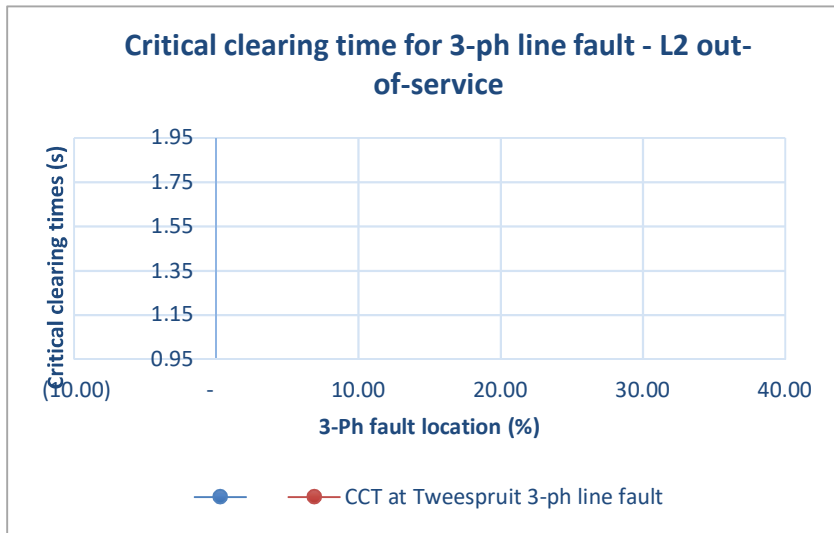


Figure 4-16: Critical clearing times profile for three-phase faults – line 2 out-of-service

From Figure 4-16, for a fault application at 0.1 s from steady-state condition, the CFCTs results for faults at 10% of the EMB-Tweespruit and Mabote-Maputsoe transmission lines showed longer transient stability limits of 1.177 s and 1.026 s respectively.

Because of the large impedance when line 2 was out-of-service, the CFCT was longer in comparison to the CFCT when circuit 2 was in-service and the voltage was unstable post fault clearance.

In the case of the faulted condition on 10% of the Mabote-Maputsoe transmission line, the breaker at Maputsoe substation tripped to clear the fault and was followed by the inter-trip operation tripping the breaker at Mabote substation after a time delay (see Figure 4-17).

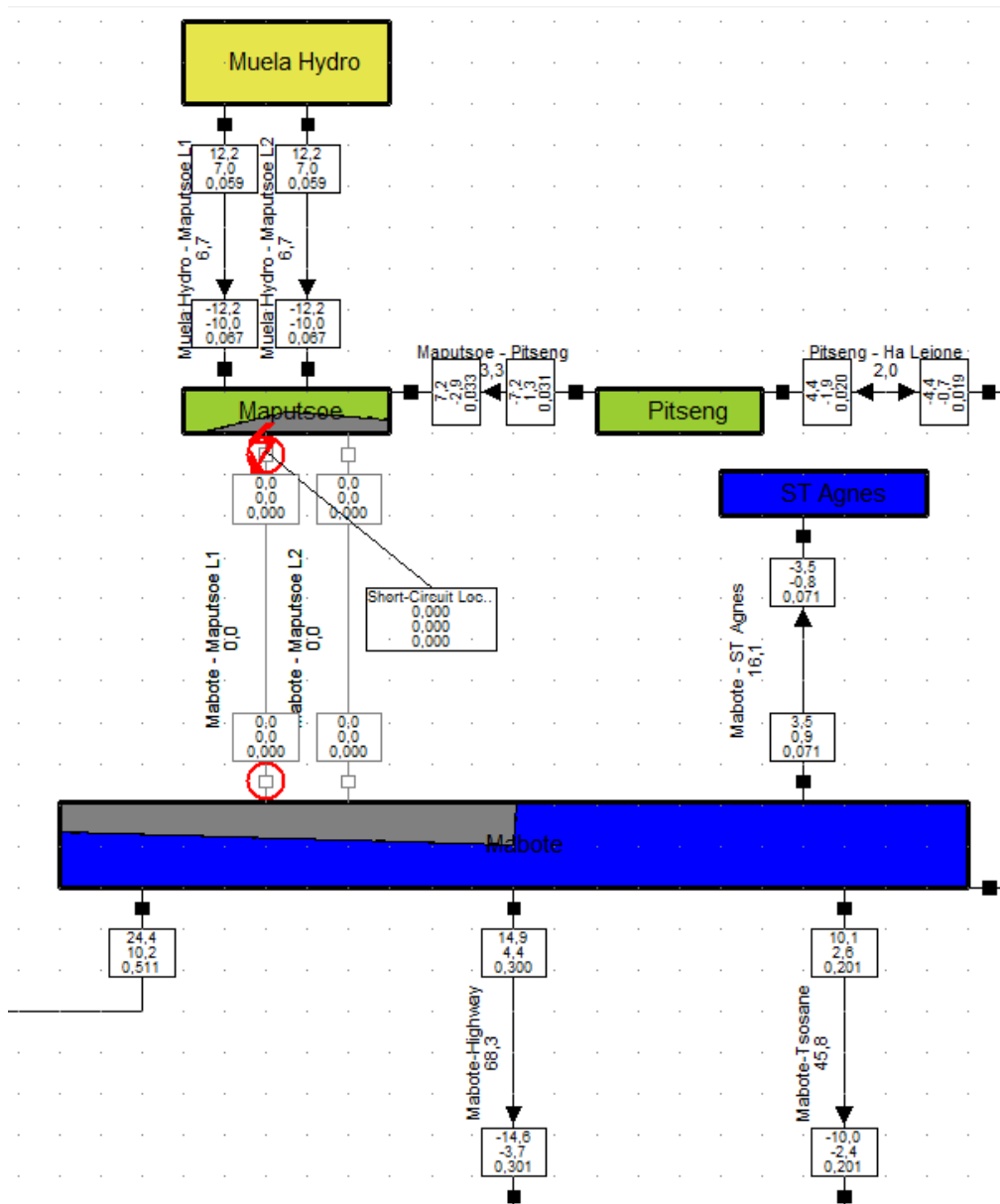


Figure 4-17: The schematic diagram showing part of the Lesotho transmission system with breakers tripped on the three-phase fault

In the case of the fault on the Mabote-Maputsoe transmission line, the impact of the fault was:

- Voltage suppression at the Mabote substation and the Maputsoe, Lejone and all other substations' busbars (see Figure 4-18)
- The frequency violations for a period longer than 4 s;
- The system lost synchronism when the fault clearing time exceeded the CFCT;
- The generators lost synchronism when running at 107% of the rated speed; the existing overspeed protection is set at 109% of the rated speed, and
- The tie-line was operating above the rated SIL of 60 MW.

Note: More simulations on the system response during this fault are provided in Annexure 4-2.

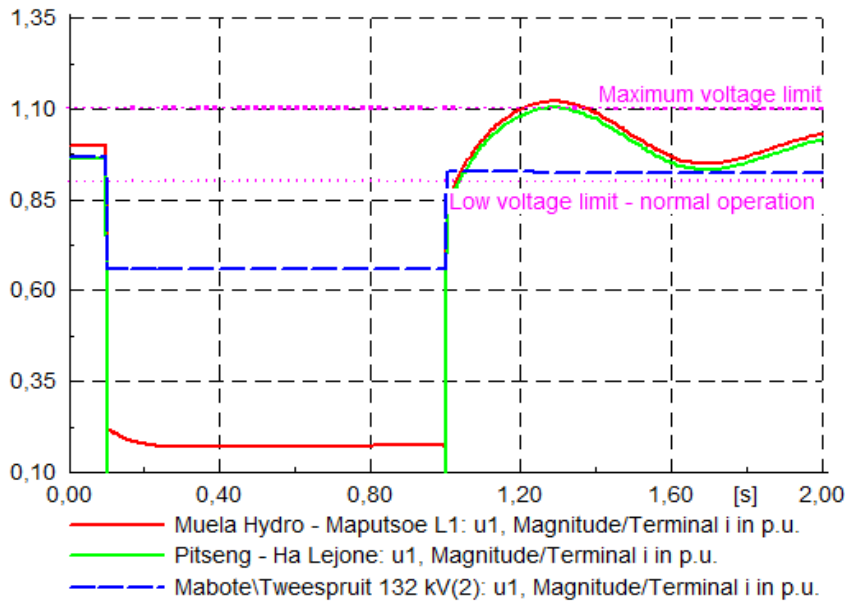


Figure 4-18: The voltage in per unit during a three-phase fault on the Mabote-Maputsoe transmission line

From Figure 4-18, the study judged the voltage and frequency limits against provisions of emergency operation when circuit 2 was out-of-service on any of the critical transmission lines. Under this condition, because of a high transmission line impedance resulting in a higher voltage drop, some of the loads downstream became voltage unstable for the duration of the emergency condition. The same is true for faults on the Tweespruit-EMB transmission line under a similar fault condition.

4.5.2.3 Single-phase-to-ground faults on Tweespruit-Mabote & Mabote-Maputsoe

The fault was applied on different transmission line locations from i-bus for both the Tweespruit-EMB and Mabote-Maputsoe lines. The tests considered a scenario of a faulted condition on line 1 when line 2 was healthy and in-service. The healthy phases transmitted power during the fault. The system stability was tested for different fault clearing times ranging from 0.4 s to 1.0 s. The system was voltage unstable and frequency stable during the fault (see more system response scans in Annexure 4-3).

The single-phase fault did not pose serious stability constraints on the generators, however, the system components such as the 132 kV transmission lines exceeded their thermal limits when the fault duration was increased up to 1.9 s. The unsymmetrical faults on the system caused the generators to also produce unsymmetrical currents.

The simulations show that the single-phase-to-ground fault was the least severe line fault with reduced stress on the generating units. The system can resist single-phase-to-ground faults much longer than the other line faults (2-ph, 2-Ph-G, 3-ph). The ratification is that the value of reactance during the fault is inversely proportional to the fault type, the FCT thereof stems from the fault type [10] and fault location.

4.5.3 System faults at the Mabote 33 kV busbars

Mabote substation is central to the transmission system and connects directly to five 33/11 kV substations (see Figure 4-19); the connected substations supply approximately 44.54 MW. These loads constitute 30% of the total Lesotho power system load, hence the importance of an evaluation of the impact that each fault type puts on the system. The transient stability in this study case tested the impact of the faults on the Mabote 11 kV and 33 kV busbars. The considered fault types were three-phase, double-phase, and single-phase-to-ground faults that were applied on the busbars for different study cases.

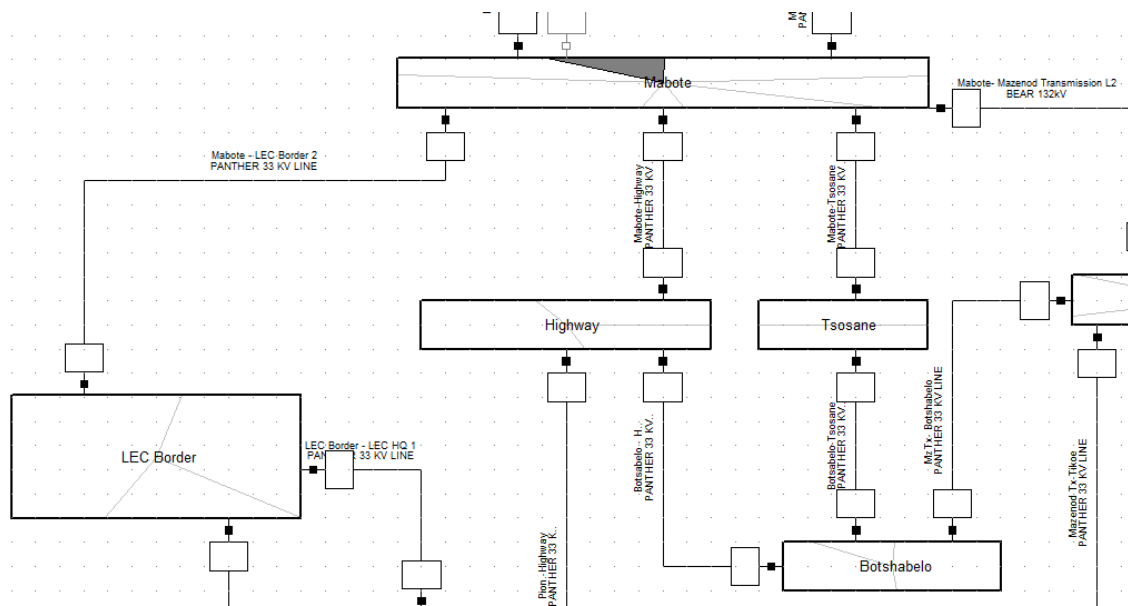


Figure 4-19: block diagram showing the substations that connect directly to Mabote substation

The simulations' output for the transient stability tests are provided in Table 4-6. The outcome of each study case was evaluated against whether the system was transient stable following the fault clearance. The procedure for testing the contingencies was:

- A fault applied on either Mabote 33 kV or the 11 kV busbars;
- The breakers tripped to isolate the faulted portion of the system;
- The limit for the faulted duration was set at 2 s;
- Computation of the CFCT for both cases, and
- The identification of the system elements that became unstable.

Table 4-6: Critical contingencies and impact on Mabote 132 kV substation

Fault type	Location	Critical clearing time	Frequency stability	Voltage status
3-ph	Mabote 33 kV BB	1.442 s	Unstable	Unstable
2-ph-G	Mabote 33 kV BB	N/A	Stable	Unstable
1-ph - G	Mabote 33 kV BB	N/A	Stable	Unstable
3-ph	Mabote 11 kV BB	N/A	Stable	Unstable
2-ph-G	Mabote 11 kV BB	N/A	Stable	Unstable
1-ph - G	Mabote 11 kV BB	N/A	Stable	Unstable

Considering the outputs of the different fault types in Table 4-6, taking the line-line fault for example, the faulted condition resulted in unstable voltage conditions, but a stable frequency for the duration of the fault condition (see Figure 4-20). The simulations showed that for the faults on Mabote substation, three-phase disturbances caused asynchronous operation if cleared beyond the CFCT at 33 kV and above. The asymmetrical faults were less severe and had reduced impact on system stability. The simulations were set up to apply a fault at 0.1 s and clear the asymmetrical fault after 2.1 s.

During the line-line fault, the line impedance varied, making it difficult to establish the limits, however, the fault current reaches the highest value when the impedance is zero. Because of the high fault currents flowing to the fault location for both faulted phases, the voltage was suppressed and in this case the voltage suppression exceeded the threshold for emergency operation (see Figure 4-20). The operating limits on a healthy system is $\pm 5\%$ and they change to $\pm 10\%$ during an emergency condition.

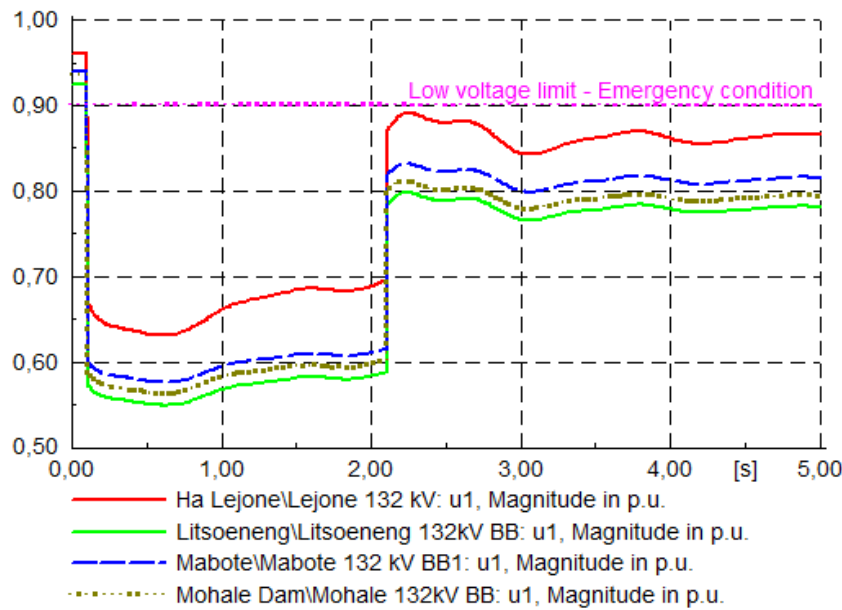


Figure 4-20: Positive sequence voltage in per unit during a double-phase short-circuit on the Mabote 33 kV busbars

4.6 Impact of loss of one generator during island operation

The system successfully islanded in the past, also during the testing and commissioning [57] in 1998. Then, the total Lesotho power system load was less than 72 MW. The recent increase in system loading and the absence of dynamic load-shedding makes it difficult to island as successfully as in the past. If the dynamic load-shedding scheme described in 4.5.1 is adopted for system operation, system island operation can succeed. During island operation, various faults or system perturbations can still occur that can lead to the tripping of one of the generating units. When one generating unit trips, with reference to 4.5.1, a supply/demand mismatch confronts the system and a system collapse becomes inevitable.

Considering study case 8 for implementing a load-shedding scheme in which generator 3 tripped at 40 s, the effect was increased active power on the two running generating units. The reactive power on the in-service generators increased, but within the installed generators' capacity limit, while the active power increased to 28.81 MW which exceeded the generators' rated active power limits. In Figure 4-21 and Figure 4-22, even though the system was voltage and frequency stable post the generator trip event, the generators' thermal overload limit was a constraint to the continuity of service. The increased load on the in-service generators resulted in a rotor angle increase from 37.7° to 43.6° .

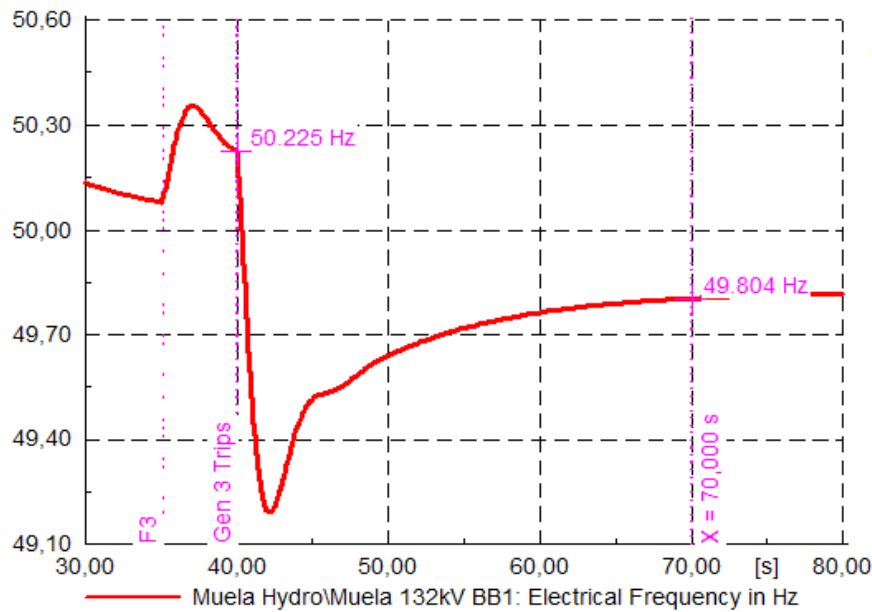


Figure 4-21: Frequency in Hz during a generator trip event

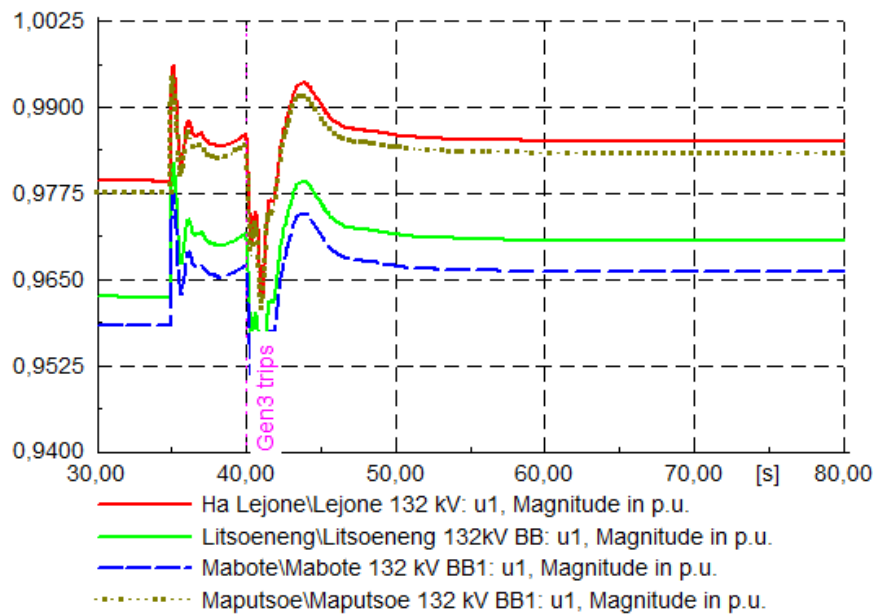


Figure 4-22: Voltage in per unit during a generator trip event

4.7 Evaluation of SVC impact during the tie-line loss contingency

Because of the power oscillations that challenged the system during breaker operation resulting from various system faults, an inclusion of a fast SVC unit as a mechanism for absorbing the oscillations to within less harmful levels was investigated. The transient stability was tested with the SVC in-service to assess the impact on transient stability and the benefits of the SVC installation on the system. The simulations followed the same procedure as those described in sections 4.5.1 to 4.5.3.

The system was voltage unstable during a three-phase fault upstream to Mabote substation in the absence of the SVC installation. This analysis covered the impact of the SVC installation for voltage stability at the 132 kV busbars. The analysis considered the installation of a static var compensator (SVC) rated at +5 to -15 Mvar at Mabote substation, as the voltage improvement technique. With the SVC in-service, the transient angle stability margin decreased compared to the study case without the additional reactive power source (see Figure 4-23).

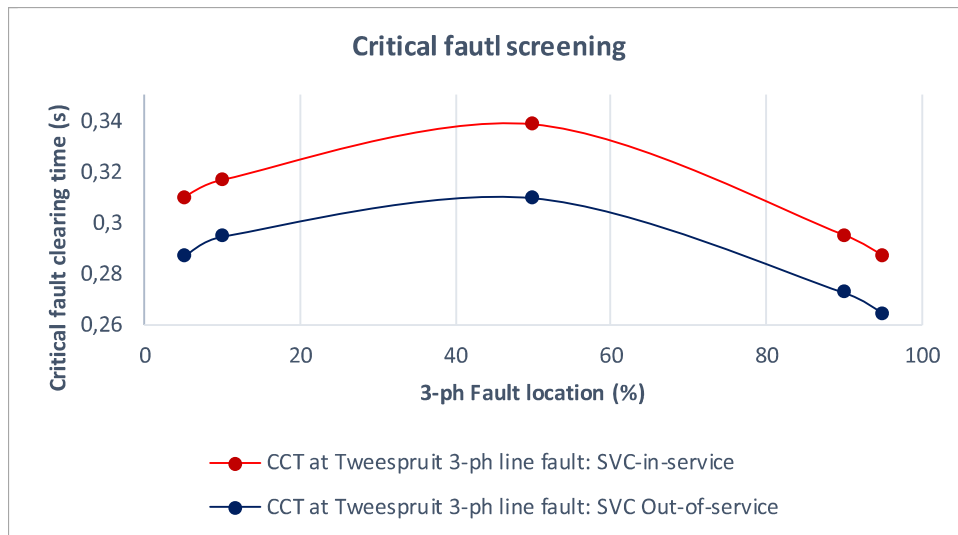


Figure 4-23: Impact of SVC on the critical fault clearing time

Implementing this technique impacts the system as follows during transient conditions:

- Improved active power transfer on the transmission lines
- Reduced stress on the excitation system
- Improved frequency suppression during islanding
- Improved excitation voltage
- Improved generator speed response to dynamic conditions
- Improved bus voltage, and
- Higher rotor angle with reference to bus voltage resulting in a reduced stability margin.

Even though the line faults upstream to Mabote substation are rare, when the faults occur, they affect the economy negatively, e.g. loss of production in the industrial sector. Figure 4-24 and Figure 4-25 show that the SVC installation on the system had the advantage of reduced stress on the excitation system and an improved voltage profile; however, the drawback of SVC installation is a reduced transient stability limit.

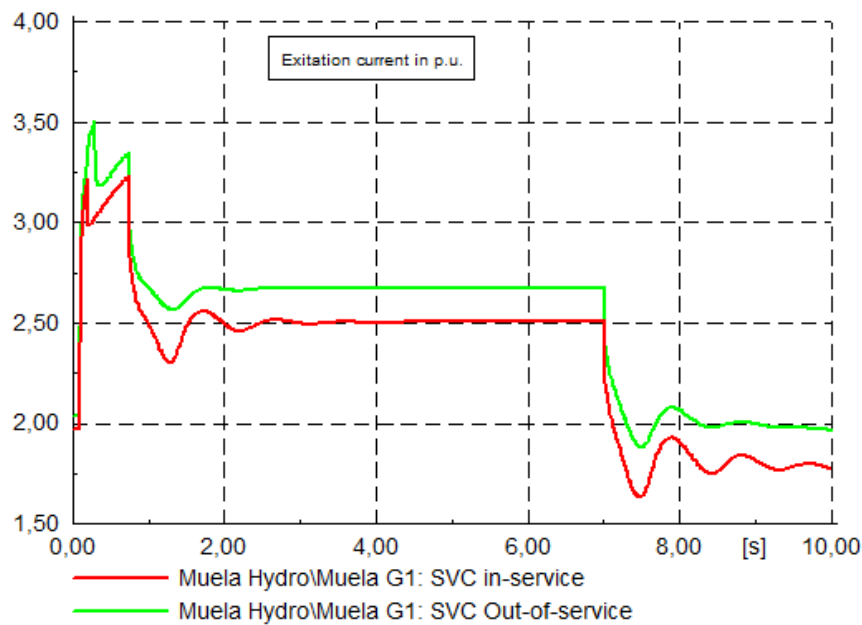


Figure 4-24: Comparison of the excitation current profile during dynamic conditions for both study cases

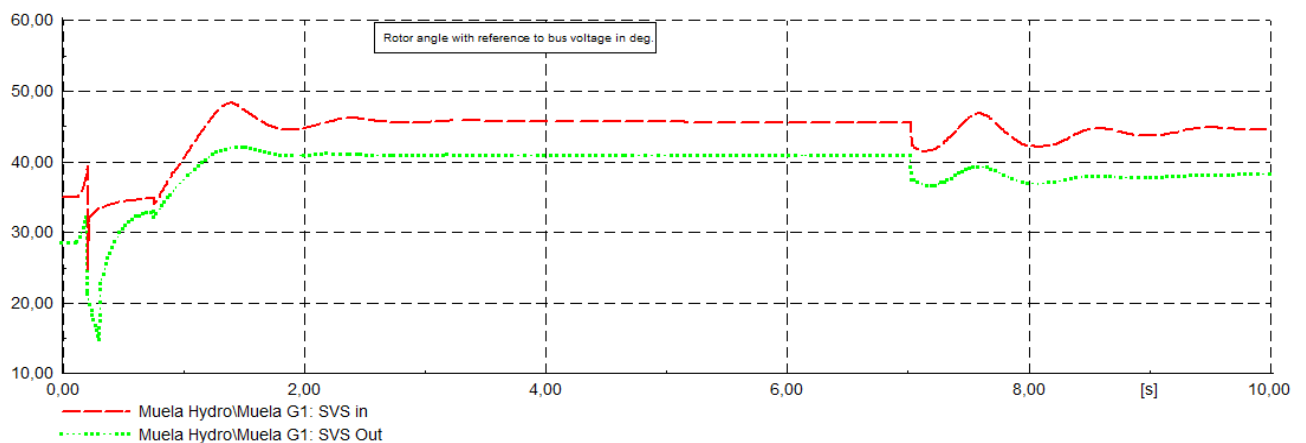


Figure 4-25: Comparison of the rotor angle characteristics during dynamic conditions for both study cases

4.8 Evaluation of system behaviour during resynchronisation

During commissioning of the ‘Muela hydropower station, the system was able to operate in island mode and was resynchronised to the grid with active load on the system. The status quo is that the generators become unstable during reconnection of the two systems. This part of the study interrogates the cause for the loss of synchronism during the reconnection to the grid by monitoring variations in voltage, frequency, and voltage angle across the open tie-line breaker points. This study uses the recommended limits for breaker closing angle, voltage difference between the two systems and frequency difference of $\pm 10^\circ$, $\pm 5\%$ and ± 0.067 Hz [56] as a guide. The recommended limit for active power oscillations on the generating units during reconnection of the tie-line is 1.5 per unit [53]. The interrogation extends to the limits within which the active power oscillations permitted successful reclosing of the two systems. The investigation entailed

applying different loading conditions on the system prior to reclosing the two systems and monitoring of the system response to each loading condition.

During synchronising of the tie-line to the system, closing the breaker resulted in transient power and current oscillations. When these oscillations are large, they can cause cumulative damage to the generators over time. The value of the load on the system at the time of closing the breaker to satisfy the conditions for synchronism, is directly related to the impact on the loss of synchronism.

Thus, the system load is directly proportional to the voltage load angle between the breaker open points when an increase in breaker load angle resulted in decreased success of closing the breaker (see Annexure 5 for simulation results). When the voltage angle is outside the $\pm 10^\circ$ limit [47], there is a risk of shaft or coupling damage to the generator sets. Table 4-7 presents the summary of the test results stemming from varying the system load from 100% to 112.3%; the system lost synchronism when the load exceeded 112.3%.

Table 4-7: Summary of system results when subjected to different loading conditions

Pre-switching load (MW)	Rotor angle max (deg.)	Peak power swing (MW)	% change in frequency	% Change in voltage	% system overload	Breaker angle at Mabote
24,10	36,7	30,60	0,5%	0,20%	100,2%	-9,7
25,14	47,7	33,29	0,8%	0,50%	105,3%	-10,1
25,79	51,3	35,03	1,0%	1,10%	108,6%	-10,4
26,3	53,8	36,20	1,1%	2,40%	111,0%	-10,6
26,52	55,5	36,90	1,2%	2,60%	111,9%	-10,7
26,59	56,0	37,10	1,2%	2,60%	112,0%	-10,7
26,64	56,3	37,22	1,2%	2,60%	112,3%	-10,8
26,85	56,3	40,37	1,3%	3,40%	113,9%	-10,8

When the generators become unstable, the output power oscillates between low and peak, the generator currents and voltages fluctuate and the maximum rotor angle increases.

The ratifications of the successful closure of the tie-line into synchronism are:

- Relationship between the system load and frequency;
- Relationship between the system load and voltage compliance,
- Relationship between the system load and the voltage load angle, and
- The system load and peak active power swing.

4.8.1 The impact of the system load on frequency

The system was frequency stable for loading conditions including a 100% to 112.3% load variation of the installed generators' capacity, the system lost synchronism for load conditions higher than 112.3%. The test results are within the typical $\pm 5\%$ voltage boundaries for closing tie-breakers into synchronism [47] and [58]. While the recommended angle for breaker closing is $\pm 10^\circ$ [56], [47], and [59], the system was stable with a breaker angle difference of up to 10.76° . The safe operating area indicates system compliance when the volts per hertz ratio was within $\pm 5\%$. Figure 4-26 portrays the boundaries for the system frequency deviation that satisfied safe closing of the tie-lines to synchronise the two systems. Noteworthy is that even though the system successfully closed into synchronism, the frequency difference was much higher than the recommended limit of 0.067 Hz [56].

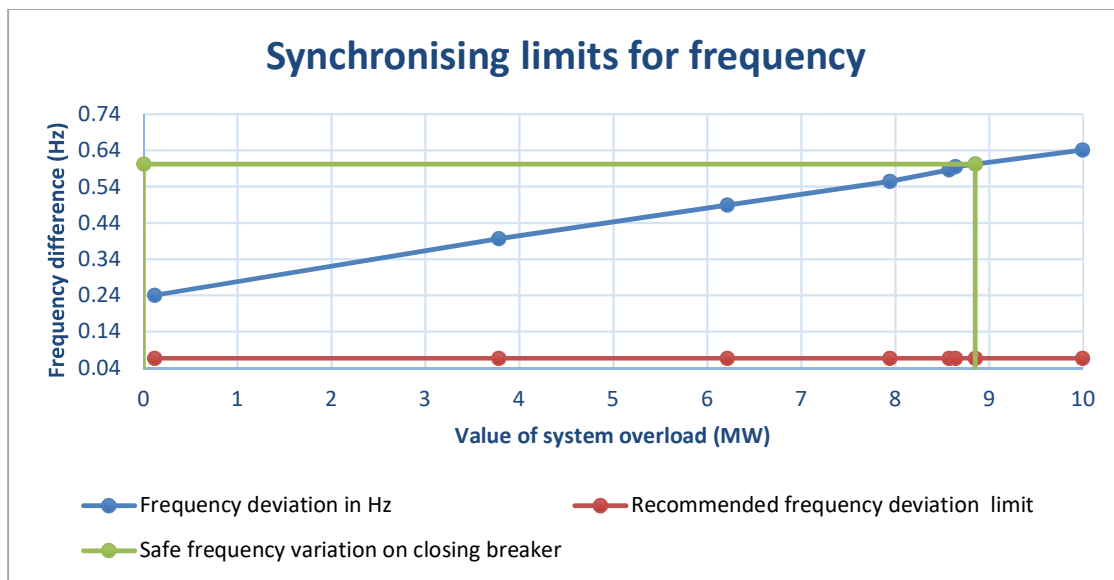


Figure 4-26: The safe breaker closing limits for successful synchronism

4.8.2 The impact of the system load on voltage difference between the two systems

The system loading conditions directly affected the voltage angle between the open breaker points; the higher the system load, the wider the angle between the breaker points. From the test results, the chances of success in closing the tie-breaker were high when the system load was below 112.3%. The limit for this loading condition is 60 s [1], beyond which it can exceed the stator heating limit. Even though the design of older systems permitted operation with a load up to 115% without the temperature rising above 60°C [60], the simulation results in Figure 4-27 demonstrated that these generators operated safely at a system load not exceeding 112.3%.

4.8.3 The impact of the system load on the load angle between the two systems

With frequency difference permitting successful breaker closing into synchronism on a load condition of up to 112.3%, the system was also voltage stable. As the voltage load angle increased across the breaker in relation to the load condition, the chances of success to synchronise decreased. Because of the foregoing, closing the tie-line when the system load is above 110% should be performed with caution to minimise failure.

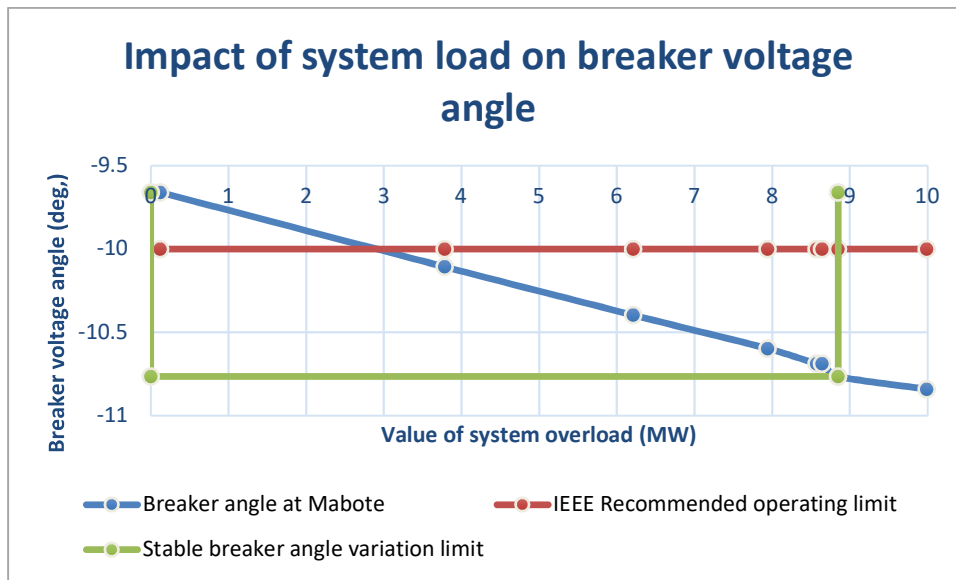


Figure 4-27: The system loading limitations for safe re-energising of the tie-line to join the two systems

4.8.4 The impact of system load on peak active power swing

From the simulation results, the active power swing oscillated back into stable operating conditions for the system load below 112.3% and with a maximum rotor angle swing of 56.3° . The simulation results depict that the limit for change in active power swings is approximately 150%, this permitted successful synchronism, power swings above 150% to 155% of the installed generators' capacity resulted in progressively declining chances of success and are thus risky.

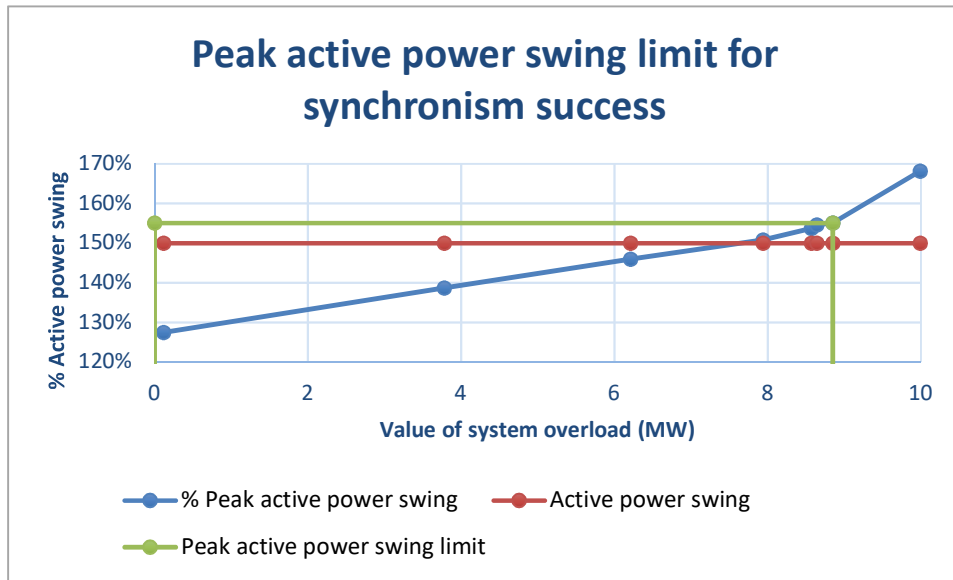


Figure 4-28: The active power swing limit for successful synchronisation of the two systems

Following successful islanding, extreme care is necessary before applying additional load on the system to avoid exceeding the overfluxing limits caused by exceeding the overexcitation limits. Prolonged system overload leads to extended excessive flux, subsequently causing overheating in generator or generator transformer [1]. The recommendations for safe system operation include the tripping of the generators when overfluxing exceeds 118% for 2 s to 6 s [3]. In consideration of the thermal limits for stator and rotor windings, the thermal operation limits permit up to 150% for less than 30 s and 125% for less than 60 s [56] respectively. The peak active power swing did not result in a violation of the excitation voltage limits, hence the excitation system operated within safe limits.

4.9 Power restoration

The power restoration accounts for strategically energizing the loads into the grid post island operation. The restoration considers the open breakers as priorities for the restoration process during the island condition. The failure effect analysis following the fault condition assumed that protection selectivity was 100% as a requisite for fault clearance. The relays nearest to the fault cleared the fault and in failure the next closest protection relay operated. Table 4-8 shows the preliminary study of the possible restoration procedure on the shed loads with the green shades indicating the loads restored per stage

Table 4-8: Schedule for restoring loads shed

Name	Value of load restored			
	Stage 1	Stage 2	Stage 3	Stage 4
Botsabelo 33 kV Load				
Highway 33 kV Load				
Katse Mohale_Out Matsoku Katse_Dam				
Litsoneng 33 kV load (M/hoek & Quthing)				
Mabote 133 kV Load				
Mazenod Dx 33 kV Load				
Metolong 33 kV Load				
Muela 33 kV BB Ngoajane Hololo Load				
Pitseng 33 kV Load				
Ramarothole 33 kV Load (Mafeteng 33 kV)				
Roma 11 Load 1				
St Agnes 11 kV load				
Tsosane 11 kV Load 1				

Figure 4-29 shows that reconnecting all shed loads instantly resulted in high system transient oscillations. When the oscillations are beyond the permissible limits, they can affect the operation of the rotating machines and other connected equipment that are sensitive to high power quality variations. In addition, the characteristics of the system variables change during the switching based on the harmonic content of the connected load during the switching operation. On the contrary, the restoration of the smaller blocks as per the schedule Table 4-8 presented less oscillation peak values.

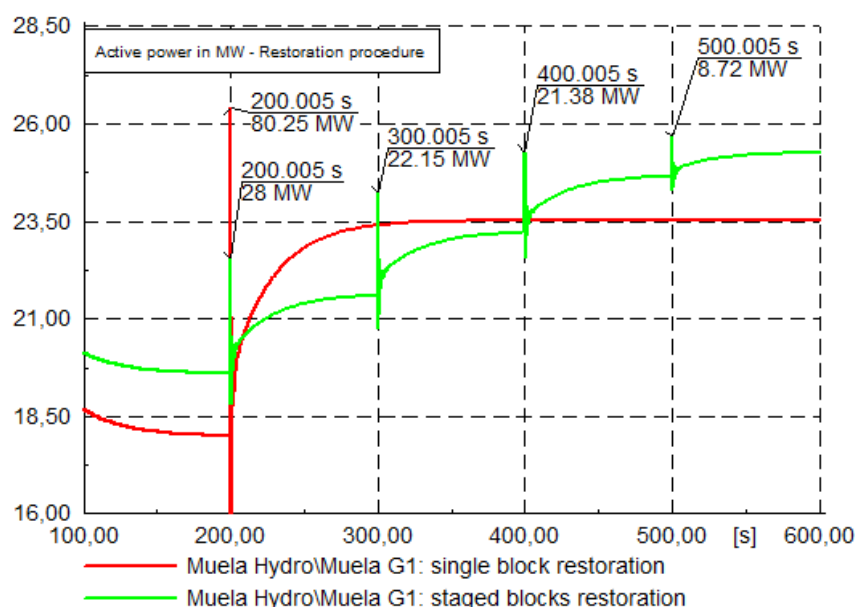


Figure 4-29: Comparison of active power profile for different load restoration approaches

With the tie-line energised at 40 s, the restoration of the loads started when oscillations subsided at 200 s with allowance of 100 s intervals between restoration stages. By restoring loads in small blocks, the generators' active and reactive power oscillations were minimal. The simulated cases indicated the hypothetical worst case scenario for restoration. In practise, operators restore loads per feeder in one station under close monitoring.

4.10 Summary

During the transmission and distribution of power, the power system can be subject to various faults; some severe and some less so and these range from three-phase faults to single-phase faults. Ideally, the expectation is that the system should operate under stable conditions; however, small changes in loading that occur continuously have an impact on the system response during dynamic conditions. Careful selection of an operational strategy on the power system enables the system to withstand large perturbations, such as faults on the tie-line, loss of the generator during island operation or line switching and peak active power swings on reconnecting the tie-line.

In the transient stability analysis, the faults cleared beyond the CFCT caused the generators to lose synchronism. During asynchronous operation, the generators tripped as a protective measure to avoid a widespread outage that could result in a complete system collapse, particularly during the loss of a tie-line. The Lesotho power system experienced large disturbances that included the 16 March 2018 incident in which the system collapsed for over three hours because of voltage, frequency, and/or angular instability. To arrest the collapse during the tie-line loss, tripping pre-identified loads solved the system supply/demand problem. Strategically tripping loads in stages with the least economic impact, ensured continued power supply to critical loads such as to the industrial sector and the capital town. The load-shedding study case 8 presented the worst-case scenario in which the loads shed stretched the system severely. Implementation of this load-shedding scheme must observe the limits defined in the requisite load-shedding scheme.

Different disturbances impact differently on the synchronous operation of the system. The three-phase faults on the tie-line, on the Mabote-Maputsoe line and on the Mabote 33 kV busbars caused the system to lose synchronism when cleared beyond the CFCT. When faults occurred on the Tweespruit-EMB or on the Mabote-Maputsoe transmission lines, the effective reactance between the two sources increased as a function of the fault type on the system. Controlled islanding helped to mitigate asynchronous operation through the use of out-of-step protection.

To alleviate asynchronous operation when energising the tie-line, the load limit on the system should not exceed 112.3%. The simulations indicated that the generators can successfully close for synchronism conditions that are slightly above the recommended limits for voltage and frequency deviation, peak active power swing and breaker angle prior to effecting the synchronous operation. Prior to concluding on the system margins, the results for application should satisfy the pre-fault, transient and post fault conditions. It is imperative therefore that the generator tripping takes place before exceeding the CFCT, so that the system regains stability post fault clearance.

Before closing the tie-line breakers to complete the grid connection, the generators must reach the adjusted synchronous speed and excitation current to achieve stable terminal voltage. The tie-line breaker closure then needs to satisfy the voltage load angle minimum requirements to permit successful closure, which will result in a stable system post the breaker operation.

CHAPTER 5 – CONCLUSIONS AND RECOMMENDATIONS

5.1 Introduction

The purpose of this study was to investigate the risks associated with the transient changes in power supply to the Lesotho network, the mitigation measures and to determine the stability limits. The application of dynamic load-shedding can mitigate the risk of system collapse during the loss of tie-lines. The permissive system load, prior to reconnection of the two systems, must be observed to achieve successful closing of the tie-line breakers.

5.2 Findings

This dissertation provides valid results through the use of DIgSILENT for the modelling of the known network parameters for both the transmission and generation parts of the system. Using tuned generator controls, viz governor, AVR and PSS, the investigation replicated the behaviour of the system for faults on various locations on the critical transmission lines or on the different busbars. Through the simulations of various scenarios, the findings for the following aspects of the study are highlighted:

- System capacity and constraints
- Past system collapse events
- Load-shedding
- Transient stability
- Generator trip event during islanding
- Conditions for synchronism, and
- Power restoration procedure

5.2.1 System capacity and constraints

The loads used on the simulations were obtained from the different substations in the year 2013 and are accurate. The simulations reflected the worst system load condition in winter, and the results of the worst dynamic cases are accurate. The outputs of this study can be adjusted to represent the load growth for future system studies.

5.2.2 Past system collapse events

The installed generation capacity cannot meet the existing total system demand. The loss of tie-lines unavoidably results in system collapse because of frequency and voltage violations. To avoid blackouts, the Lesotho power system requires surplus power to sustain the 63.93 MW required for optimal operation of the generating units. The application of dynamic load-shedding can reduce the occurrences that caused the system blackout incidents in the past.

5.2.3 Load-shedding

The Tweespruit-Mabote transmission line is critical for the stable operation of the Lesotho transmission system. By implementing staged dynamic load-shedding that considers the system load on the line, system collapse events caused by faults on the tie-lines or reduced import power to sustain the Lesotho transmission system requirements can be avoided. The stability determinant is dropping a minimum of 46.72 MW for stage 1 load-shedding; this is based on the status of the tie-line breaker to alleviate system collapse during the loss of the tie-lines.

5.2.4 Transient stability analysis

The three-phase faults on the critical transmission lines, viz Tweespruit-Mabote and Mabote-Maputsoe on line 1 when line 2 is in-service, must be cleared within 300 ms and 280 ms respectively to preserve system stability. In contrast, the three-phase faults on line 1 when line 2 is out-of-service must be cleared in 1.1 s and 0.97 s for faults on the Tweespruit-Mabote and on the Mabote-Maputsoe transmission lines respectively to improve the system's transient stability. These settings allow for three-phase short-circuit clearances at various transmission line fault locations, including 10% and 90% of the total transmission line length.

5.2.5 The SVC installation to improve voltage stability

The installation of the SVC can improve the system voltage control and reduce power oscillations during re-energising. A drawback of installing the SVC unit is a reduced system transient stability margin. Consideration to add this new device to the transmission system requires specialist study to determine the technical and economic merits.

5.2.6 Generator event during islanding

Following a successful dynamic load-shedding, the system collapses when any of the generators trip during island mode. Considering study case 8, the load-shedding scheme must allow for an additional stage 4 load-shedding and drop approximately 24 MW load based on any one of the generators tripping.

5.2.7 Conditions for synchronism

Following successful islanding, the system resynchronizes successfully when the active power load is below 112.3% of the installed generators' capacity. Resynchronization succeeds when the voltage load angle difference between open breaker points is less than 10.7° and the peak active power swing limit is restricted to 155% of the generators' capacity.

5.2.8 Power restoration procedure

Following successful resynchronization, energizing loads shed in any order do not disturb the system stability. When operators energize load per feeder per station, the system stability is preserved.

5.3 Recommendations

The recommendation is for the utilities to use the output of this study as a contribution to the foundation for further detailed studies towards improving the power system stability. Any significant changes on the system parameters require careful study, as it will affect the output of this study. The output of this study demonstrated that dynamic load-shedding is necessary to improve system stability during perturbations on the Tweespruit-Mabote transmission line for upstream faults.

Based on the simulation results, this study demonstrated that configuring a protection system to activate stage 1 load-shedding when the tie-lines' breakers open and activating the subsequent load-shedding stages if frequency decline continues, will overcome the existing supply/demand problem during disturbances on the tie-lines. The recommendation is for the utility to utilise the frequency/ voltage relay to activate the load-shedding scheme to preserve the system stability for events that occur on the tie-lines as well as the busbar faults upstream in the network.

The system loading should be limited to 100% of the generating units' capacity during loss of the tie-lines for safe closing of the tie-line breaker at minimal risk of asynchronous operation. The operators can vary the load from 100% to 110% load of the generators during islanding with decreasing chances of success as the load approaches and exceeds 110%.

The installation of the SVC system brings about various system improvements during loss of the tie-lines and during steady-state condition, however, detailed studies are necessary to inform the techno-economic viability and the inherent return on investment.

5.4 Conclusions

Application of dynamic load-shedding during the disturbances that cause power transfer failure to the Lesotho transmission system can mitigate the causes of system collapse during the loading conditions that exceed the continuous operation of the installed generators' capacity.

The transient stability limit is reached for the faults cleared beyond 300 ms and 280 ms for the Tweespruit-EMB and Mabote-Maputsoe transmission lines. The zones 1 and 2 protection settings should consider these CFCT limits.

The study established the limits for the tie-line breaker for successful re-synchronising with the associated variances in the voltage, load angle, system load, frequency, and peak active power swing.

The results are based on the analysis of a fault at Mabote substation and the requisite limits for safe closing of the tie-line breaker into synchronism post successful island operation.

The critical fault clearing time for the three-phase fault at Mabote substation on the 33 kV busbars is 1.44 s, the longer fault clearing time results in an unstable system.

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6

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APPENDICES

Dynamic load-shedding for enhancement of power system stability for the Lesotho 132 kV transmission network

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ABSTRACT

The transient and dynamic stability are key elements that a system should satisfy to achieve stable system operation [1]. Fault type and location determine the impact that each fault puts on the system and whether power generators stay in synchronism. The Eskom-Mabote tie-line is key to satisfying Lesotho power system (LPS) peak load demand of 150 MW. Any faults on the tie-line that affect the power transfer capacity threaten the continuity of supply as they can result in system collapse. When clearing of faults is longer than the critical fault clearing time (CFCT), the generators lose synchronism and trip as a protective measure. The knock-on effect of system collapse contributes to Lesotho's struggling techno-economic standing.

The absence of a contingency to counteract the effects of the tie-line failure and so minimize the impact on the supply/demand mismatch, often results in frequency violations. Using DigSILENT, this study investigates the impact of the tie-line failure during the peak load and proposes load curtailment measures by employing dynamic-load shedding to avoid complete system collapse. Secondly, the study outlines the solutions to overcome the existing supply/demand challenge during tie-line failure to minimize the recurrence of system collapse. Thirdly, the study investigates the causes of failure to resynchronize and the impact of live system load to satisfy the requisite resynchronizing requirements, viz. change in voltage, frequency, and load angle. The study also reflects on the impact of different amounts of live loads during restoration considering the hypothetical extreme cases.

Keywords—power system stability, dynamic load-shedding, critical fault clearing time, tie-line, system collapse

I. INTRODUCTION

To meet the peak demand exceeding the capacity (72 MW) of the installed generator units, the LPS imports the surplus power from the Grid through the Eskom-Mabote tie-lines. When the tie-lines trip, the network collapses because of overload condition. A severe fault at EMB or upstream in the network or reduced import power from the grid caused system collapse including on the 8th May 2016 and 16th March 2018. To avoid recurrence of system collapse caused by similar system contingencies, the study applies load-shedding investigated in eight study cases by dropping varying amounts of load to achieve 64 MW live load. The objective of tripping different loads is to find the optimal load-shedding scheme that results in a stable system with the least number of customers affected. The determination for the total loads dropped consider the 8 MW [2] and 4.87 MW for operating reserve and system losses respectively.

Secondly, the investigation evaluates the impact of clearing the three-phase faults on the lines in normal zone 1

and zone 2 protection times of 0.0 s and 0.5 s respectively. The investigation uses the simulations to determine the critical fault clearing time (CFCT) to judge the system stability when severe faults occur on EMB or upstream in the network. The outcome of the CFCT assists to determine whether the system is transiently stable when subjected to contingencies. A fault clearance time within the CFCT represents a stable system.

Lastly, upon re-closing the tie-line breaker, the system saw failure in resynchronizing. This outcome necessitates tripping the generators and resynchronize them into the system after reaching stable operating condition. Tripping the generators results into increased imported peak demand, -increased cost to the utility. The objective of the investigates on this part is to establish the safe system loading conditions that will permit successful resynchronizing into the system. Using the requisite conditions for resynchronization published in [3] and [4] as a guide, the study judges the limits to which the outcome satisfy IEEE Std C50.13 of 2014 [5, p. 15] with attention to resynchronizing load, breaker load angle, frequency deviation and peak active power swings.

II. THE SYSTEM MODELING APPROACH

A. The 2013 system load profile

The study makes use of 30 minutes system load data measured from all the Lesotho Electricity Company (LEC) substations, compressed using moving average toolbox in Microsoft Excel (see Eq.(1)) to achieve overall smooth trends in Fig. 1.

$$F_t = \frac{A_r + A_{t-1} + \dots + A_{t-n+1}}{n} \quad (1)$$

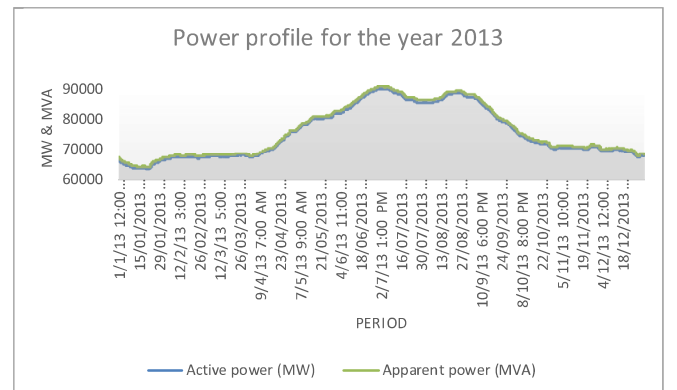


Fig. 1: The active and apparent power profile- July 2013

Taking July 2013, the peak load occurred between 08:00 and 09:00. The load profile indicates no direct relationship between active power and reactive power consumed. The data shows that the increase in active power consumed was not

directly proportional to the reactive power consumption. To represent the system peak load of 150 MW recorded in 2016, the load was increased proportionally on all substations. Noteworthy is that another set of data provided by LEC in the form of monthly consumption summary for 2017 indicates a reduced peak demand of 118 MW.

B. Voltage and frequency dependency of loads

The study determined the load composition to be neither static nor dynamic hence the adoption of complexed load model to represent the load composition. In DIGSILENT [6], the complex load model represents the combination of static and dynamic loads. Embedded in the simulation tool, Eq. (2) and (3) mathematically model the voltage and frequency dependency of the static portion on the load. According to [6], these equations use a potential approach that considers the static portion of the load as constant impedance.

$$P = P_0 \left(\frac{v}{v_0} \right)^{k_{pu}} * \left(1 + k_{pf} \left(\frac{\Delta f}{f_0} \right) \right) \quad (2)$$

$$Q = Q_0 \left(\frac{v}{v_0} \right)^{k_{pu}} * \left(1 + k_{pf} \left(\frac{\Delta f}{f_0} \right) \right) \quad (3)$$

The simulations assumed a balanced three-phase load and adopted the DIGSILENT exponent values of 1.6 *kpu* and 1.8 *kpu* [6]. To characterize the constant PQ model, the application of the exponents' settings in Eq. (2) and (3) characterize the voltage and frequency dependency of load during dynamic conditions.

To model the dynamic load portion, DIGSILENT applies Eq. (4) to mathematically describes the characteristics of the dynamic loads.

$$t_e = \left[\frac{T_{mo}}{100} \right] \left[\frac{v^2}{v_0^2} \right] \left[\frac{s}{s_0} \right] \left[\frac{s_0^2 + s_{cr}^2}{s^2 + s_{cr}^2} \right] \quad (4)$$

C. The system models

The model used the external grid as a voltage source that has impedance to represent the physical characteristics. Noteworthy is that not only the grid parameters determine the success in balancing the power in the system, the load flow calculation tool allows for definition of power control mechanism implemented in steady-state. The grid acceleration time constant represented the combined inertia for all the connected systems [6].

The 'Muela hydro-power is rated 96 MVA, it uses the synchronous generators to covert the mechanical energy to electrical energy. To characterize the generators' behavior during dynamic conditions, the model used the gov_Hygov, IEEE1 and PSS2A to model the governor, automatic voltage regulator (AVR), and power system stabilizer (PSS) respectively. During the contingencies, to analyze the impact of the disturbance, the variables such as generator active power, generator rotor angle, speed, and rotor angle were recorded to examine the system behavior.

The Lesotho transmission and distribution system consists of mostly two winding (132/33 kV) and few three-winding (132/66/11 kV) transformers. The model used a detailed transformer model that included on-load tap changers to control voltage, phase angle or both etc. [6].

The longest transmission line is less than 80 km, not transposed, and thus falls within the short line category [6]. The model used the standard DIGSILENT overhead line data

for load-flow and RMS simulations, and still achieved reasonable results. The conductors used in the model are 'bear' for 132 kV and 'panther' for 33 kV lines.

III. THE CAUSE AND EFFECT OF PERTURBATIONS ON ESKOM TIE-LINE

When the tie-line trips, the constraint for continued supply of power is the 96 MVA installed generating units. With no dynamic load-shedding scheme, the system collapses because of frequency violations resulting from the mismatch in supply/demand. The computations for establishing the total load to be shed allowed 8 MW [2], [7] for spinning reserve to meet Southern African Power Pool (SAPP) operational requirements and 4.87 MW for the system losses (for the LPS only).

In the past five years, LPS experienced various blackout conditions including the 8th May 2016 and 16th March 2018 incidents. This study used two hypothetical study cases, i.e. busbar faults on Tweespruit substation with and without dynamic load-shedding to examine the system behavior during events that caused power transfer failure to the LPS.

A. Busbar faults in Tweespruit substation – No dynamic load-shedding application

On application of a three-phase fault on the busbars at Tweespruit substation, the protection operation resulted in power transfer failure on the tie-lines. The system collapsed because of frequency violations (see Fig. 2). Other system violations included the generator loading and voltage.

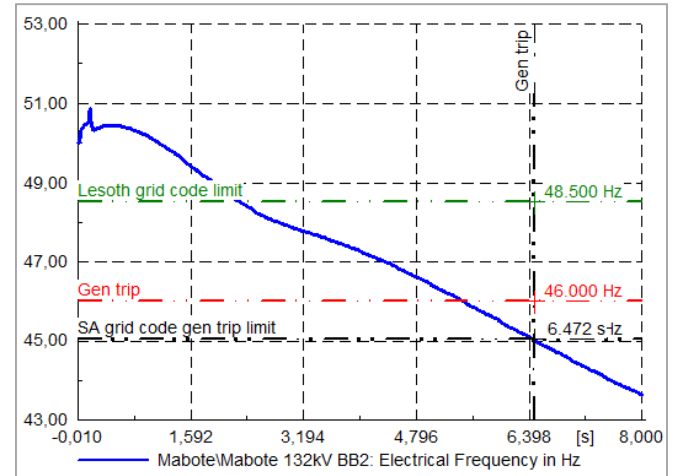


Fig. 2: The frequency characteristics during faulted condition at Tweespruit substation

B. Busbar faults on Tweespruit substation – with dynamic load-shedding application

To prevent system collapse, various combinations of loads were tripped during stage 1 ranging from 73.17 MW to 46.72 MW to evaluate the impact on the system for the least to most effective combination for optimal results (see Table 1).

Table 1: Different amounts of loads tripped for different study cases

Stage	Cumulative value of load-shed per stage							
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8
1	73,17	67,51	64,72	64,72	64,72	57,25	49,15	46,72
2	86,86	88,49	87,75	74,57	74,57	59,48	65,46	76,25
3	93,52	90,55	89,81	89,81	85,36	63,33	72,19	80,25
4	-	-	-	-	89,21	77,85	76,25	-
5	-	-	-	-	-	81,21	80,25	-

The load-shedding operations considered the different study cases to assess the system response. The success of the operation depended on tripping the substations that connect directly to Mabote substation (see Fig. 3), because of its location, for stage 1 while the succeeding stages were a combination of loads excluding the manufacturing sector and Central Business Districts (CBDs) to mention but a few essential load centers.

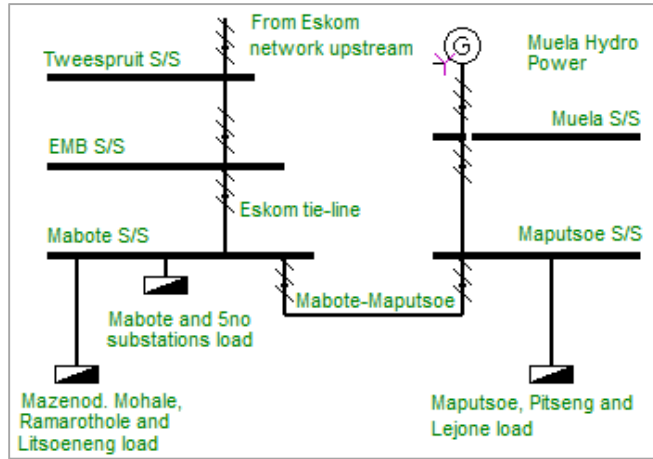


Fig. 3: The schematic diagram showing the part of the network that connects to Mabote substation

With reference to Table 1 with attention to the study cases 6 to 8, the simulations show that the system frequency recovered post the operation of stage 2 load-shedding (see Fig. 4). The important variables monitored were active power and reactive power, line-line voltage and excitation voltage.

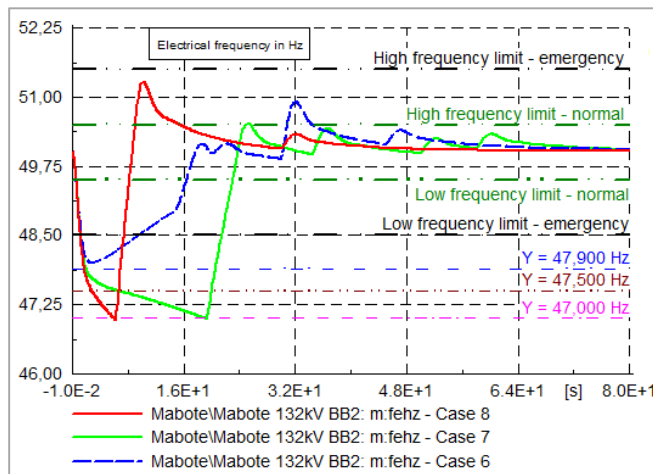


Fig. 4: Comparison of frequency (Hz) response for study cases 6 to 8

Taking study case 8 as the optimal solution, dropping 46.72 MW for stage 1 and allowing for a 6.82 s time delay before activation of stage 2 resulted into a frequency fall to 47.0 Hz, frequency recovered on application of stage 2 load-shedding.

From Fig. 4, the activation of stage 2 resulted in fast frequency recovery because of dropping 29.53 MW, the recovery complied with the requirements of [8] for the frequency limits of 48.5 Hz to 47.5 Hz but violated 47 Hz limit ($t < 3.86$ s) during emergency conditions. The Lesotho grid code does not specify the limits.

Considering study case 8, in Fig. 5 to Fig. 7, the simulations showed compliance on the following post the dynamic load-shedding operation:

- The active power and reactive power were stable, but required another load-shedding stage to meet the operational reserve;
- Voltage was stable for emergency condition limits, and Excitation system settled down.

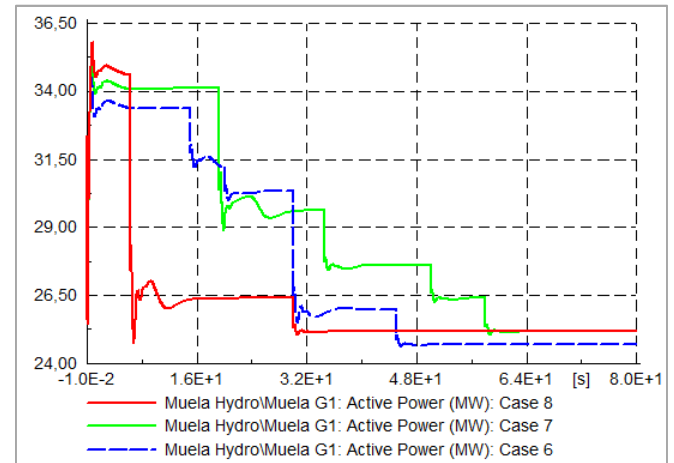


Fig. 5: The active power response to dynamic load-shedding operation for study cases 6 to 8

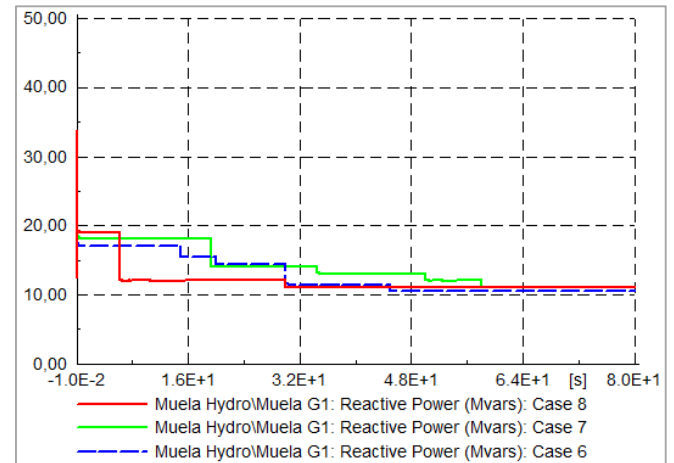


Fig. 6: The reactive power response to dynamic load-shedding operation for study cases 6 to 8

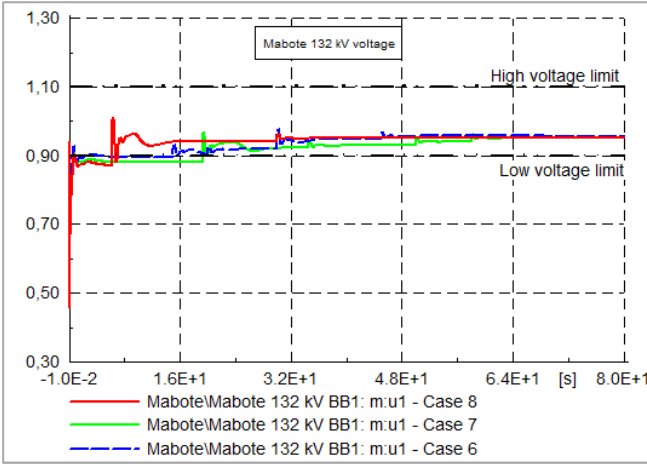


Fig. 7: The line-to-line voltage characteristics to dynamic load-shedding operation for study cases 6 to 8

IV. THE INVESTIGATION OF SYSTEM TRANSIENT STABILITY

When faults occur on the system, they cause overloads, voltage violations, frequency violations and threaten the system stability if the protection system is not activated on time [1], [9]. The system stability is judged by the ability of the generators to maintain synchronism during and / or after a faulted condition on the system [10, p. 47]. The loss of synchronism is an undesirable outcome owing to threats that come with out-of-step operation.

The generation and load mismatch during the fault condition initiate transients that cause the rotor to swing, because of the acceleration or braking torque applied on the rotor [1], [9]. In the perturbations, the breaker tripping operations clear faults and isolate the faulted section of the system.

Considering the faulted condition on the tie-lines, a fault was applied on the transmission line at different locations to establish the critical fault clearing time (CFCT). In analyzing each case, the CFCT is important because it determines if the system is transiently stable. The computation of actual clearing time originates from Eq. (5)[9].

$$K_{time} = \frac{(t_{cr} - t_f)}{t_{cr}} \quad (5)$$

Where

t_{cr} is critical clearing time

t_f is actual clearing time

K_{time} is transient stability margin

From reference [1], the determination of system stability together with the computations of critical clearing angle δ_c follow Eq. (6).

$$\delta_c = \cos^{-1} \left\{ \left[\frac{1}{r_1 - r_2} \right] \left[\left(\frac{P_m}{P_M} \right) (\delta_m - \delta_0) \right] + r_2 \cos \delta_m - r_1 \cos \delta_0 \right\} \quad (6)$$

Where

P_M – peak pre-fault power angle curve

r_1 – peak of power angle curve ratio of the faulted circuit to P_M

r_2 – peak of power angle curve ratio to P_M with fault cleared

$$\delta_0 = \sin^{-1} \left(\frac{P_m}{P_M} \right) < \frac{\pi}{2}$$

$$\delta_m = \sin^{-1} \left(\frac{P_m}{r_2 \times P_M} \right) > \frac{\pi}{2}$$

A. Procedure for testing the contingencies

- The procedure for testing the contingencies was:
- A fault was applied on the line in the range of 5% to 95% of each line length at 100 ms;
- The line tripped at the substations at varying times until it reached and or exceeded the CFCT;
- The line tripped at node-j (j- denoting the other end of the faulted line) because of inter-trip activation;
- Calculation of the values for critical clearing times and critical clearing angle for both cases, and

Identification of the system elements that were unstable.

B. Critical fault clearing time (CFCT) application procedure

The simulations of the faulted conditions in this study used the CFCT technique, which uses an iterative process [6]. In testing the transient stability limit, the focus was to determine the CFCT for different fault types on the critical transmission lines, viz. Tweespruit-EMB and Mabote-Maputsoe. The scenarios included a fault applied on line 1 when line 2 was in-service and a fault on line 1 when line 2 was out-of-service on both critical transmission lines.

The simulations' output included monitoring the dynamic variables and results thereof to assess the fault impact on the system. The monitored variables and their importance are:

- Active and reactive power – during island operation, the generators should operate within their capability limits to avoid unsafe operating area.
- Excitation voltage – changes the amount of reactive power produced which is necessary to maintain stable generator terminal voltage.
- Rotor angle of the generator –determines the amount of torque and the rotor current injection to maintain constant generator terminal voltage.
- Speed of the generator – provides an indication of the relationship between the generated active power and the load active power during islanding.
- Line-to-line voltage – is necessary for healthy operation of the equipment and loads connected to the system and for voltage compliance purposes.
- Phase currents – are necessary for determination of active power, voltage, and load angle.

The study used the CFCT results to evaluate the requisite settings for zones 1 and 2 in view of the stability limitations.

1) *The three-phase fault on line 1 when line 2 was in-service*

The fault was applied individually on the line location as indicated on Fig. 8 for both Tweespruit-EMB and Mabote-Maputsoe transmission lines. Considering Tweespruit-EMB transmission line, from the results in Fig. 8, the typical zone 2 settings of 0.5 s is longer than the CFCT.

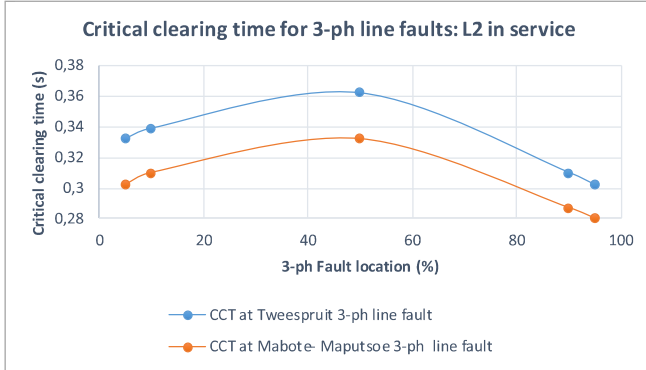


Fig. 8: The critical fault clearing time for a three-phase fault on the critical transmission lines

The simulation results using DIgSILENT indicate that the lowest CFCT of 0.302 s was reached for a faulted condition on 90% of the protected Tweespruit-EMB transmission line. These results for various fault location (see Fig. 8) show that that loss of synchronism is eminent for settings with a longer time delay than the CFCT. Considering the Eq. (5)), the decisions on settings should allow for a stability margin.

Taking a detailed look at a fault applied at 10% of the Tweespruit-EMB transmission line length, the CFCT was 0.34 s. With a fault applied at 100 ms from steady state, the CFCT occurred at 0.44 s. The stability was determined by adjusting the trip time from 0.44 s (CFCT), 0.45 s and 0.5 s to monitor the generator rotor angle on fault application. The results show that the system was stable up to 0.44 s (the CFCT) and pole-slipped on application of 0.45 s fault clearing time (see Fig. 9).

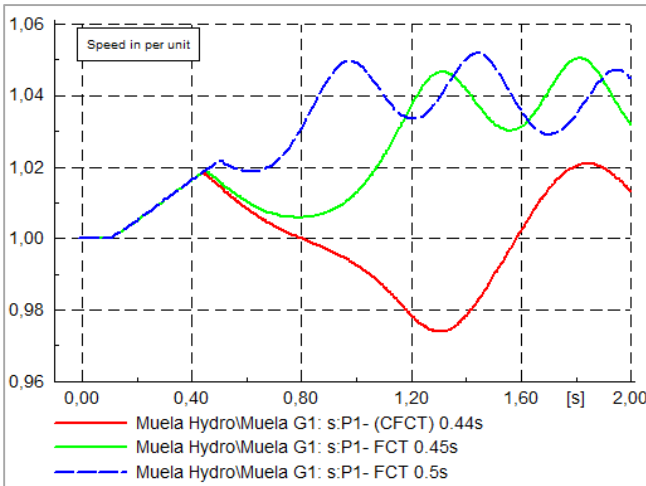


Fig. 9: Generator speed characteristic showing out-of-step condition for fault clearance time exceeding the CFCT

2) *The three-phase fault on line 1 when line 2 was out-of-service*

Considering maintenance on either line and that the faults happen abruptly, a severe three-phase fault was applied on

both the critical transmission lines independently on different line fault locations (see Fig. 10). The procedure stated in section IV, 'A' was followed. Because of line 2 being out-of-service, the overall system impedance increased hence the increased stability margin for this contingency. The simulations showed that for the faulted condition at 10% of Tweespruit-EMB and Mabote-Maputsoe transmission lines lengths, the CFCT was 1.119 s and 0.988 s respectively.

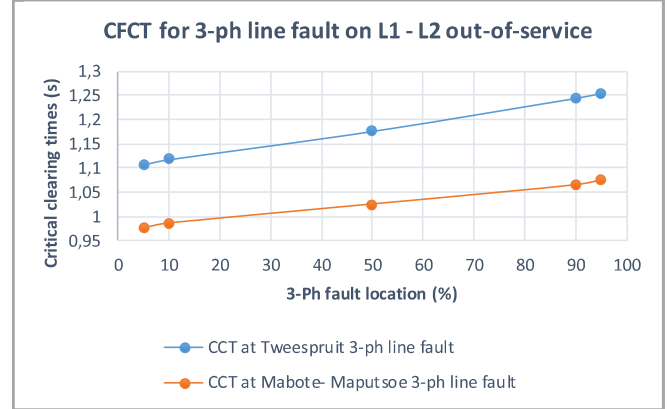


Fig. 10: The critical fault clearing time for a three-phase fault on the critical transmission lines

For faults close to the Eskom side of these lines with the second line out of service, resulted in:

- Voltage suppression at all substations (see Fig. 11);
- Generators losing synchronism when running at 107% of the rated speed, and
- The transmission line was operating at a higher load than 60 MW surge impedance loading.

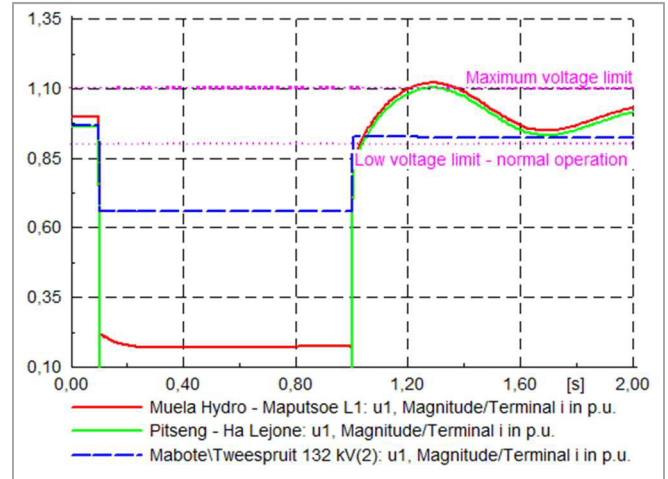


Fig. 11: A voltage response to a three-phase fault with line 2 out-of-service

3) *The three-phase fault on Mabote 33/11 kV busbars*

The substations connecting directly to Mabote substation supply approximately 44.54 MW. This constitutes $\pm 30\%$ of the total Lesotho power system load (see Fig. 3) making an investigation into impact that each fault type puts on the system very important.

The transient stability was tested through the application of a three-phase fault on Mabote 11 kV and 33 kV busbars

following the procedure in section IV, ‘A’. Different considered fault types were three-phase, phase-phase, and single-phase-to-ground faults. Of all these faults, only the three-phase fault on the 33 kV busbars resulted in system frequency instability (see Table 2).

Table 2: The transient stability results for Mabote 33/11 kV busbars

Fault type	Location	Critical clearing time (s)	Frequency stability	Voltage status
3-ph	Mabote 33 kV BB	1.442 s	Unstable	Unstable
2-ph-G	Mabote 33 kV BB	N/A	Stable	Unstable
1-ph - G	Mabote 33 kV BB	N/A	Stable	Unstable
3-ph	Mabote 11 kV BB	N/A	Stable	Unstable
2-ph-G	Mabote 11 kV BB	N/A	Stable	Unstable
1-ph - G	Mabote 11 kV BB	N/A	Stable	Unstable

V. INVESTIGATION OF POSSIBLE SVC INSTALLATION IMPACT

Bearing in mind that both active and reactive power oscillations occur during the re-energizing, the amplitude of power oscillations beyond the generators’ ratings warranted an investigation into the impact a static var compensator (SVC) would have on the LPS. The advantage of installation was improved voltage control, because of being an additional source while the drawback was a reduced stability margin (see Fig. 12).

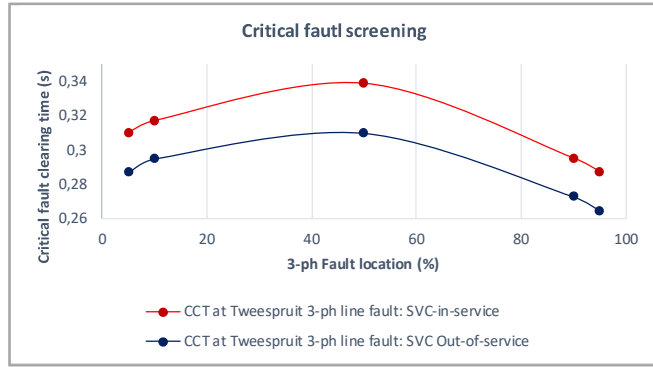


Fig. 12: Impact of SVC installation on the critical fault clearing time

VI. ANALYSIS OF SYSTEM BEHAVIOR DURING SYNCHRONIZING

Since 1998 when ‘Muela hydro-power’ was commissioned, the load on the LPS has increased. In 2016, the peak load demand was 150 MW because of an increased industrial activity and commercial developments. With no dynamic load curtailment to permit islanding during emergency conditions, the supply /demand balance accuracy remains fragile.

The status quo is that the system does not resynchronize to the grid assuming a successful island operation. To reconnect the two systems, ‘Muela hydro-power generators trip and are resynchronized after the grid picked-up the load. This paper further investigated the causes and factors that contribute to the tie-line breaker’s failure to close. Using [4] as a guide on the requisite limits for the breaker closing angle, voltage difference between the two systems and frequency difference as $\pm 10^\circ$, 0% to +5% and 0.067 Hz, the system was tested on at these conditions to establish the extreme limits within which breaker closure was successful (see Table 3).

Table 3: The summary of the load condition impact for the requisite tie-breaker closing conditions

Pre-switching load (MW)	Rotor angle max (deg.)	Peak power swing (MW)	% change in frequency	% system overload	Breaker angle at Mabote
24,103	36,713	30,602	0,50%	100,20%	-9,66
25,14	47,713	33,291	0,80%	105,30%	-10,107
25,791	51,303	35,031	1,00%	108,60%	-10,397
26,228	53,84	36,197	1,10%	111,00%	-10,598
26,516	55,539	36,903	1,20%	111,90%	-10,689
26,595	55,975	37,103	1,20%	112,00%	-10,689
26,636	56,291	37,22	1,20%	112,30%	-10,765
26,847	56,291	40,369	1,30%	113,90%	-10,842

In performing the load tests prior to resynchronizing, the impact of the peak power swing was evaluated through switching different combinations of loads. Contrary to the recommendations in [3], the 1.5 per unit limit was increased to 1.55 per unit beyond which the generating units were unstable upon closing the tie-line breaker. The next sections discuss the impact that each variable had on the breaker closing operation.

A. Breaker voltage angle variations across the open-poles

The relationship between the loading condition and the breaker voltage angle show that the limits provided in [3], [5] can be exceeded. Thus, further increase in load is indirectly proportional to the chances of success on closing the tie-line breaker. From Table 3, the breaker angle difference was enlarged from 10° to 10.77° and a function of load on the system. Further increases in load resulted in an unstable system (see Fig. 13).

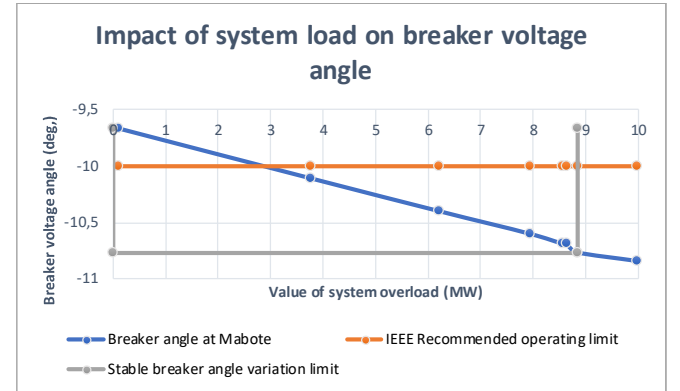


Fig. 13: The system overload limits to permit safe tie-line breaker closing

B. Voltage difference between the two systems

From Table 3, the voltage variations were within the recommended limits in [5], [10] for different permissive breaker close requirements. The reduced voltage variation is important for improved power system stability by permitting the reactive power into the system [10].

C. Frequency variations

Different to the recommendations in [4], the simulations’ results show that synchronizing is permissive above the 0.067 Hz up to 0.6 Hz for increasing system load conditions (see Fig. 14). Reference [10] characterizes large frequency differences to rapid load pickup or even excessive machine motoring mode operation.

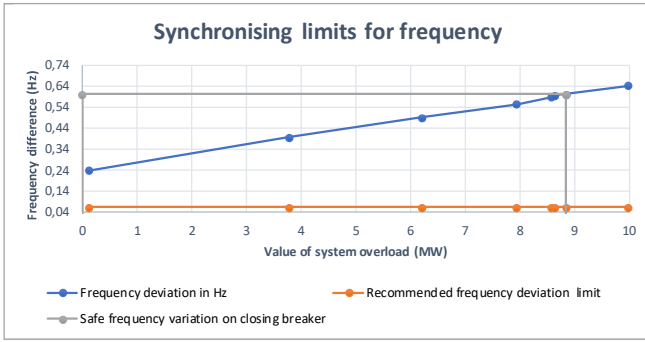


Fig. 14: The frequency variation limit for safe breaker closing into synchronism

D. Peak active power swing limit on closing the tie-line breaker

Divergent to the limits in [3], the simulation results show that the peak active power swing oscillated back in to stable condition with the maximum rotor angle oscillations swing of 56.3° . From Fig. 15, the results further show that the peak active power swing permits stable operation including 100% to 155% of the generator rated capacity with progressively declining chances of success.

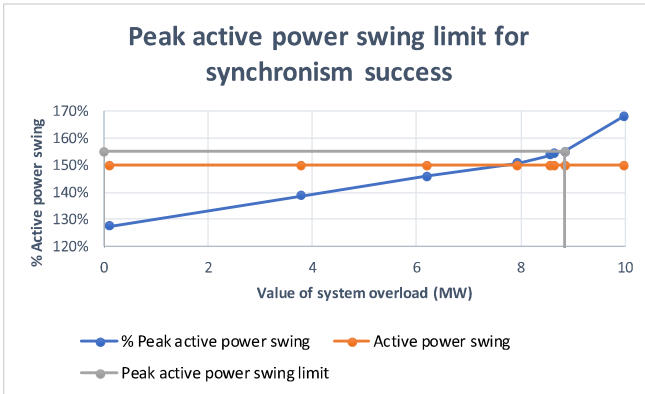


Fig. 15: Peak active power swing limit for successful synchronizing

VII. IMPACT OF DIFFERENT POWER LOAD RESTORATION ON THE SYSTEM

The load restoration was tested considering two scenarios, viz. restoring the all loads shed in hypothetically one switching action versus restoring the loads in small blocks. The simulations show that the two scenarios had minimal impact on the generators (see Fig. 16). In practice, the operators restore loads through switching one breaker load at the time.

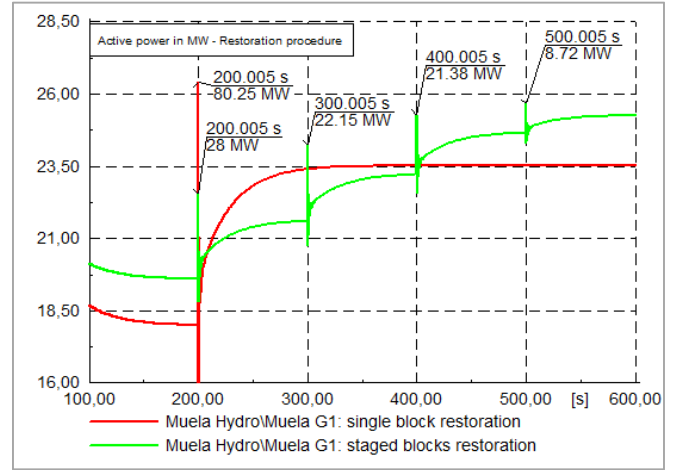


Fig. 16: Comparison of the impact of restoring different amounts of load on the generating units

VIII. CONCLUSION

The outcome of this study provides valid solutions achieved through use of DIGSILENT for system modelling.

Application of dynamic load-shedding during perturbations that cause power transfer failure to the Lesotho power system can solve the causes of system collapse during loading more than the installed generators' rating.

The transient stability is reached with the application of faults with clearing times of 300 ms and 280 ms respectively for the Tweespruit-EMB and Mabote-Maputsoe transmission lines with both lines in-service.

The installation of an SVC to absorb power oscillations during the perturbations can also improve the voltage stability. However, the drawbacks of this solution include reduced stability margin.

The study established the limits for successful re-synchronizing with the associated variances in the voltage load angle, system load, frequency, and peak active power swing.

Loads restoration in any sequence does not compromise the generators' operating limits.

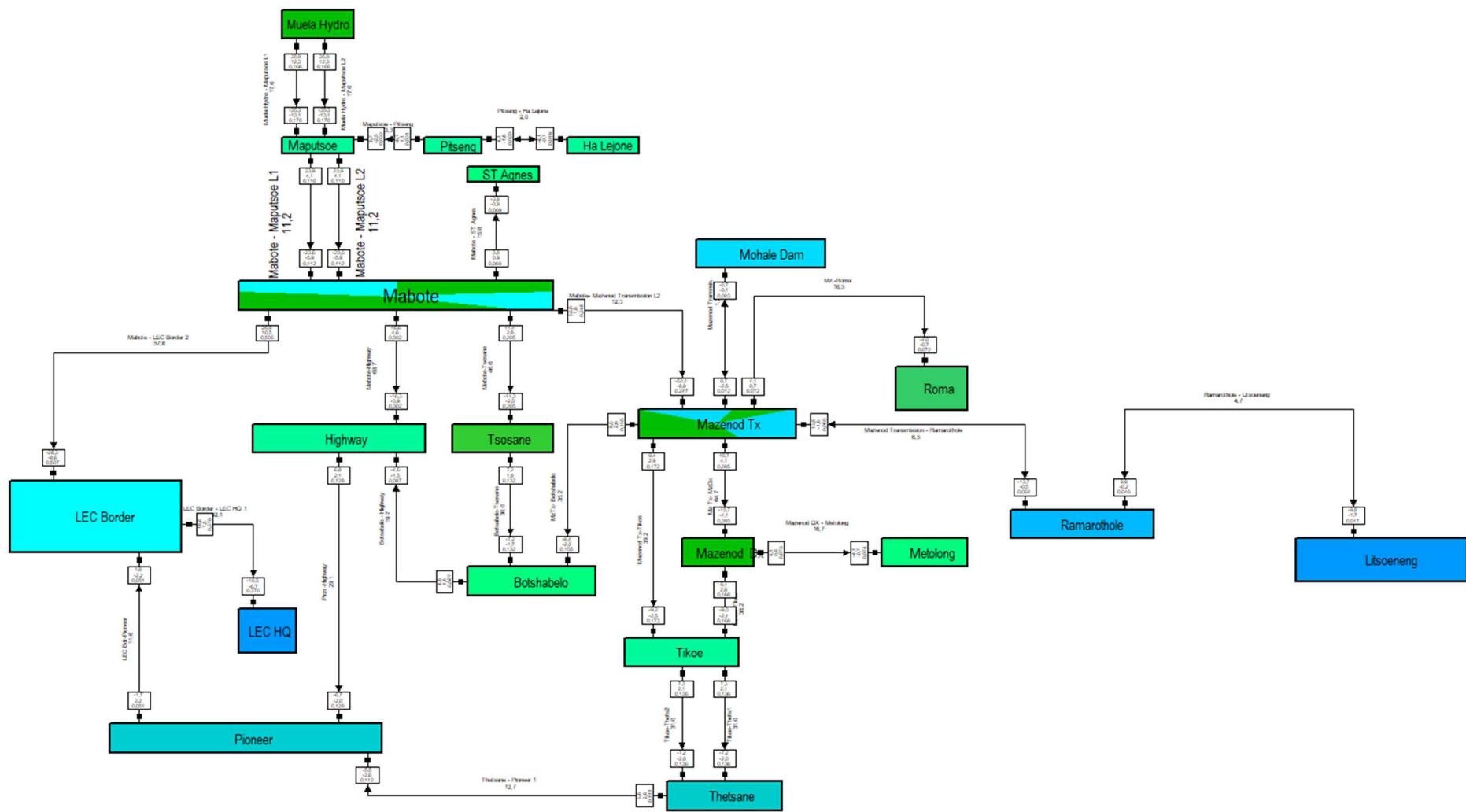
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- [5] IEEE Power and Energy Society, "IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators rated 10 MVA and Above," IEEE-SA Standard Board , New York, USA, 2014.
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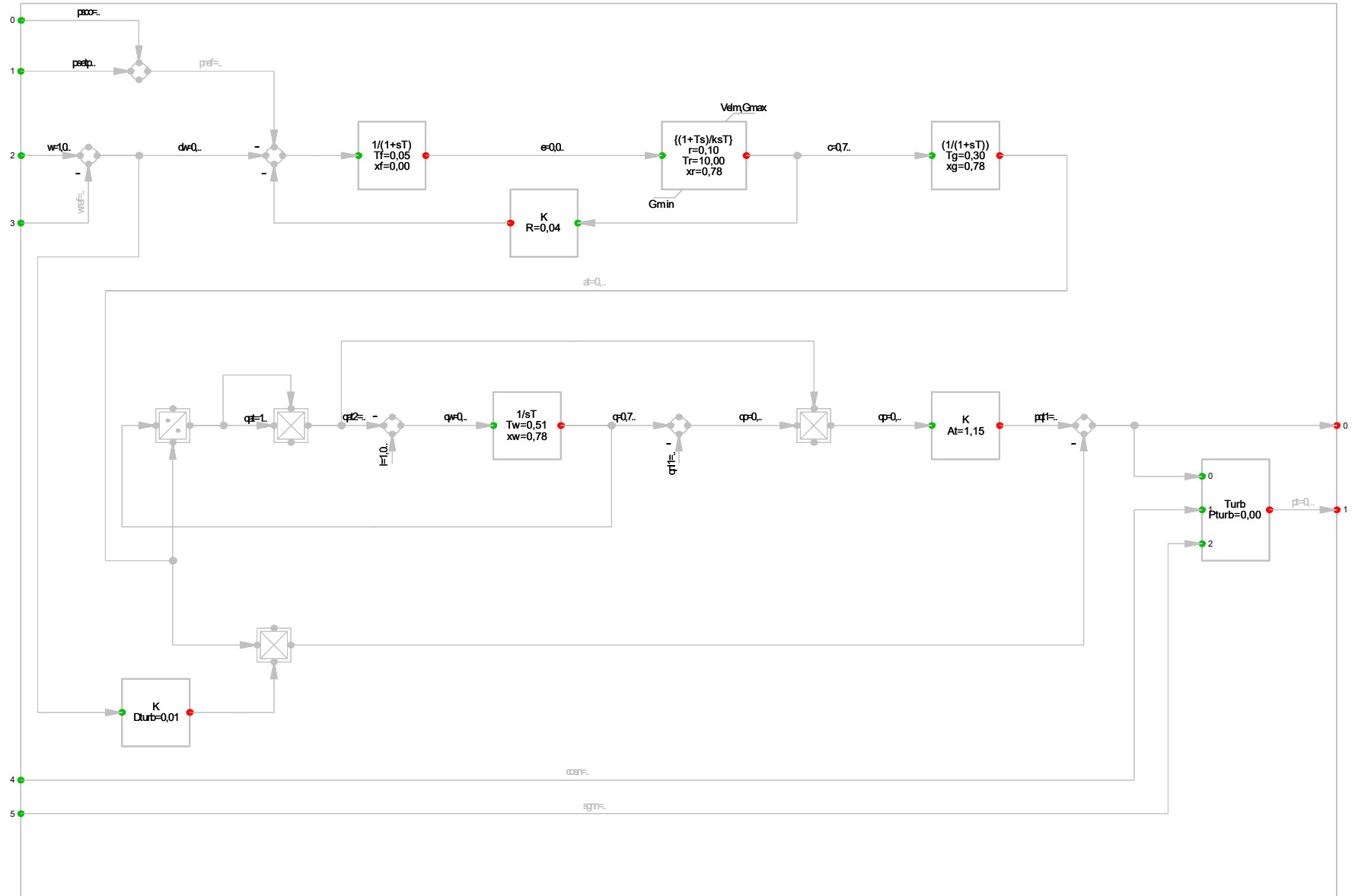
ANNEXURES

Annexure 1: The Lesotho power system single line diagram (embedded in word file and in separate pdf file)



Annexure 2: The automatic voltage regulator (AVR) space model for IEEE T1

gov_HYGOV_Test: Hydro Turbine Governor



Annexure 3: The combination of loads dropped for load-shedding in study case 1 to 8

The annexure shows the different combinations of loads tripped for different study cases. In study case 1, 73.17 MW of load was tripped for stage 1 load-shedding, resulting in less frequency decline; less load was tripped progressively for the different study cases until the least load of 46.72 MW was tripped for study case 8. The annexures for this section of the study are split into two parts, viz:

- A.3-1: Schedule of loads shed for study cases 1 to 5
- A.3-2: Schedule of loads shed for study cases 6 to 8

		A.3-1: Schedule of loads shed for study cases 1 to 5																
		Case 1			Case 2				Case 3			Case 4			Case 5			
Name	Active Power (MW)	Stage 1	Stage 2	Stage 3	Stage 1	Stage 2	Stage 3	Stage 4	Stage 1	Stage 2	Stage 3	Stage 1	Stage 2	Stage 3	Stage 1	Stage 2	Stage 3	Stage 4
												Stage 1	Stage 2	Stage 3				
Botsabelo 11kv Load 1	5,44	5,44			5,44				5,44			5,44			5,44			
Botsabelo 11kv Load 2	5,44	5,44			5,44				5,44			5,44			5,44			
HA Lejone 11kV Load 2	1,02									1,02				1,02				
Ha Lejone 11kV Load 1	1,02									1,02				1,02				
Highway 11kV Load 1	6,99	6,99			6,99				6,99			6,99			6,99			
Highway 11kV Load 2	6,99	6,99			6,99				6,99			6,99			6,99			
Hlotse Adit loads	0,01																	
Katse Mohale_Out Matsoku Katse_D	2,06						2,06				2,06			2,06			2,06	
LEC HQ 11kV Load 1	9,18	9,18			9,18				9,18			9,18			9,18			
LEC HQ 11kV Load 2	9,18	9,18			9,18				9,18			9,18			9,18			
Lec Border 11kV Load 1	2,83	2,83																
Lec Border 11kV Load 2	2,83	2,83																
Litsoneng 33kV load (M/hoek & Quthing)	9,85		9,85			9,85				9,85			9,85			9,85		
Mabote 11kV Load	7,01	7,01			7,01				7,01			7,01			7,01			
Mabote 11kV Load2	7,01	7,01			7,01				7,01			7,01			7,01			
Maputsoe 11kV Load 1	8,00														8,00			
Maputsoe 11kV Load 2	8,00																	
Mazenod Dx 11kV Load	2,44	2,44			2,44				2,44			2,44			2,44			
Metolong 33 kV Load 1	2,03			2,03													2,03	
Metolong 33 kV Load 2	2,03			2,03													2,03	
Mohale Dam 11kV Load 1	0,36																	
Mohale Dam 11kV Load 2	0,37																	
Morija	0,18																	
Muela 33kV BB Ngoajane Hololo Load	4,67					4,67				4,67				4,67			4,67	
Pioneer 11kV Load 1	7,02				-													
Pioneer 11kV Load 2	7,02				-													
Pitseng 11kV Load	2,61			2,61		2,61				2,61				2,61				
Ramarothole 33kV Load (Mafeteng 11 kV)	3,84		3,84			3,84				3,84				3,84				3,84
Roma 11kV Load 1	2,00																	
Roma 11kV Load 2	2,00																	
St Agnes 11kV load	3,78	3,78			3,78													
Thetsane 11kV Load 1	4,44																	
Thetsane 11kV Load 2	4,44																	
Tikoe 11kV Load 1	1,92																	
Tikoe 11kV Load 2	1,80																	
Tsosane 11kV Load 1	2,03	2,03			2,03				2,03			2,03			2,03			
Tsosane 11kV Load 2	2,03	2,03			2,03				2,03			2,03			2,03			
Total load shed per stage	149,87	73,17	13,69	6,66	67,51	20,97	2,06	-	63,73	23,02	2,06	63,73	9,85	15,24	64,72	9,85	10,79	3,84

A.3-2: Schedule of loads shed for study cases 6 to 8

A.3-2: Schedule of loads shed for study cases 6 to 8																	
		Case 6						Case 7						Case 8			
Name	Active Power (MW)	Stage 1	Stage 2	Stage 3	Stage 4	Stage 5	Stage 6		Stage 1	Stage 2	Stage 3	Stage 4	Stage 5		Stage 1	Stage 2	Stage 3
Botsabelo 11kv Load 1	5,44	5,44							5,44						5,44		
Botsabelo 11kv Load 2	5,44	5,44							5,44						5,44		
HA Lejone 11kV Load 2	1,02																
Ha Lejone 11kV Load 1	1,02																
Highway 11kV Load 1	6,99	6,99							6,99						6,99		
Highway 11kV Load 2	6,99	6,99							6,99						6,99		
Hlotse Adit loads	0,01																
Katse Mohale_Out Matsoku Katse_D	2,06		2,06								2,06					2,06	
LEC HQ 11kV Load 1	9,18																
LEC HQ 11kV Load 2	9,18																
Lec Border 11kV Load 1	2,83	2,83															
Lec Border 11kV Load 2	2,83	2,83															
Litsoneng 33kV load (M/hoek & Quthing)	9,85				9,85					9,85						9,85	
Mabote 11kV Load	7,01	7,01							7,01						7,01		
Mabote 11kV Load2	7,01	7,01							7,01						7,01		
Maputsoe 11kV Load 1	8,00																
Maputsoe 11kV Load 2	8,00																
Mazenod Dx 11kV Load	2,44		2,44						2,44							2,44	
Metolong 33 kV Load 1	2,03					2,03						2,03				2,03	
Metolong 33 kV Load 2	2,03					2,03						2,03				2,03	
Mohale Dam 11kV Load 1	0,36																
Mohale Dam 11kV Load 2	0,37																
Morija	0,18																
Muela 33kV BB Ngoajane Hololo Load	4,67				4,67						4,67					4,67	
Pioneer 11kV Load 1	7,02																
Pioneer 11kV Load 2	7,02																
Pitseng 11kV Load	2,61		2,61							2,61						2,61	
Ramarothole 33kV Load (Mafeteng 11 kV)	3,84			3,84						3,84						3,84	
Roma 11kV Load 1	2,00												2,00				2,00
Roma 11kV Load 2	2,00												2,00				2,00
St Agnes 11kV load	3,78	3,78							3,78						3,78		
Thetsane 11kV Load 1	4,44																
Thetsane 11kV Load 2	4,44																
Tikoe 11kV Load 1	1,92																
Tikoe 11kV Load 2	1,80																
Tsosane 11kV Load 1	2,03	2,03							2,03						2,03		
Tsosane 11kV Load 2	2,03	2,03							2,03						2,03		
Total load shed per stage	149,87	52,38	7,11	3,84	14,52	4,05	- 169		49,15	16,30	6,74	4,05	4,01		46,72	29,53	4,01

Annexure 4: The additional simulation scans for transient stability on the Tweespruit-EMB and Mabote-Maputsoe transmission lines

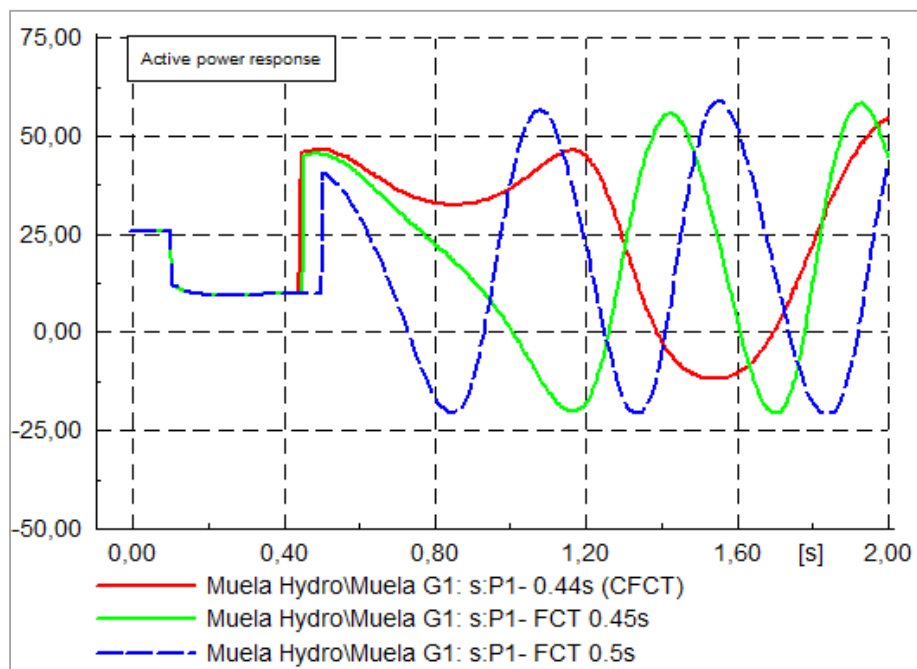
The simulation scans in this annexure provide additional system characteristics during different transient stability tests. The annexure is divided into three sections representing different faults, viz:

- A.4-1: A three-phase fault on the Tweespruit-EMB line 1, line 2 was in-service; a fault was applied at 10% of the transmission line length
- A.4-2: A three-phase fault on Mabote-Maputsoe; a fault was on line 1, line 2 was out-of-service
- A.4-3: A single-phase fault on the Tweespruit-EMB line 1, line 2 was in-service; the fault was applied at 50% of the transmission line length

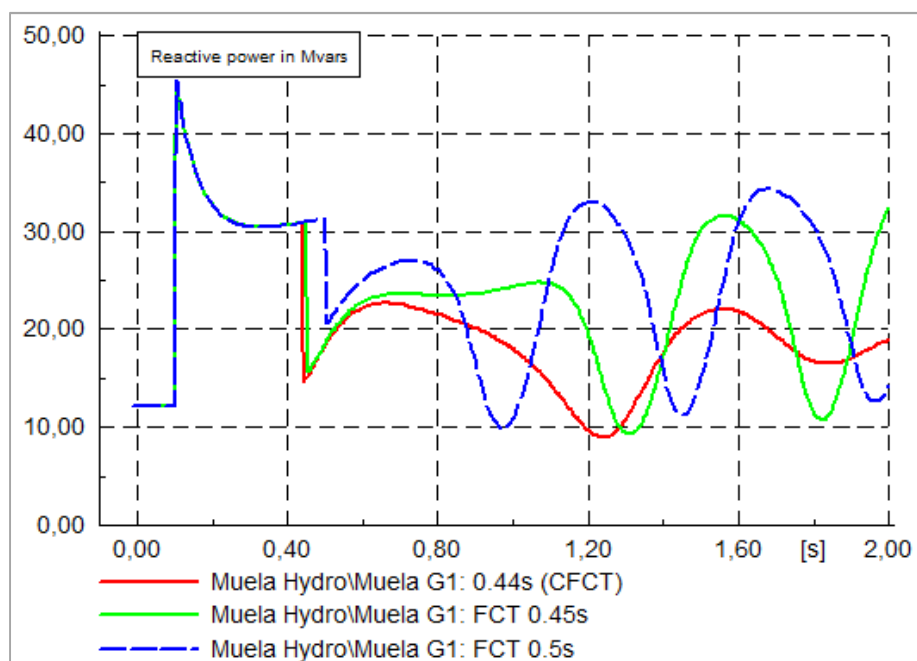
A.4-1

A fault was applied at 0.1 s and tripped at 0.4s, 0.44 s(CFCT), 0.45 s and 0.5 s. The additional scans show the synchronous generators' active and reactive power, excitation voltage, generator torque, line-to-line voltage and phase currents.

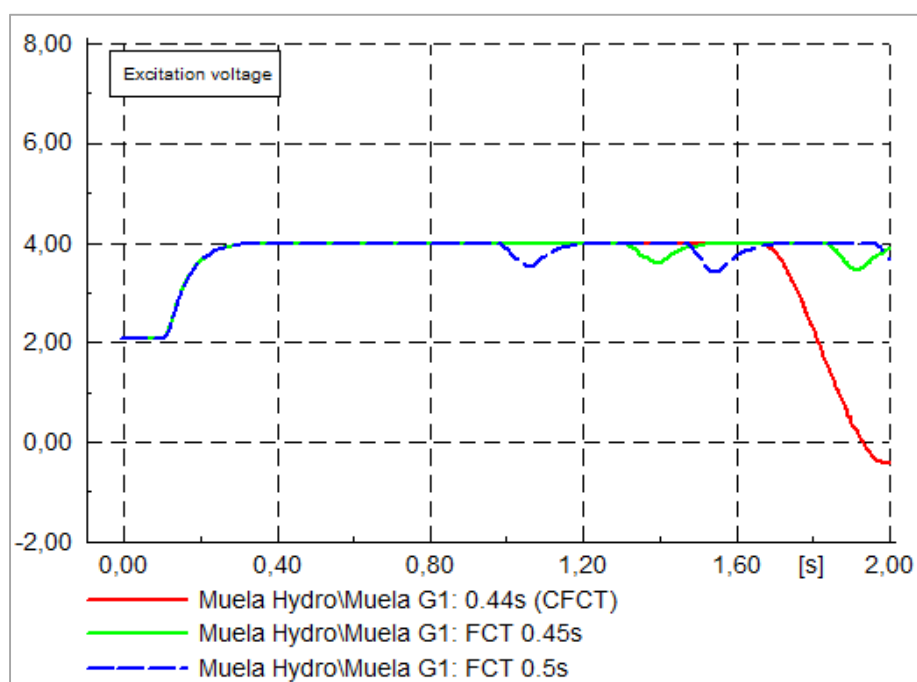
A.4-1-1: Active power response



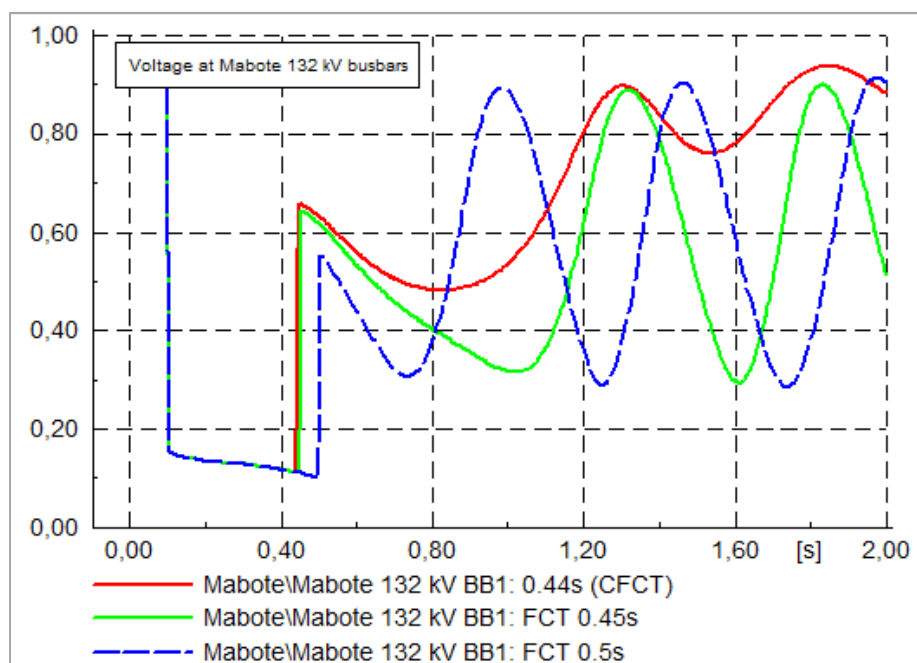
A.4-1-2: Reactive power response



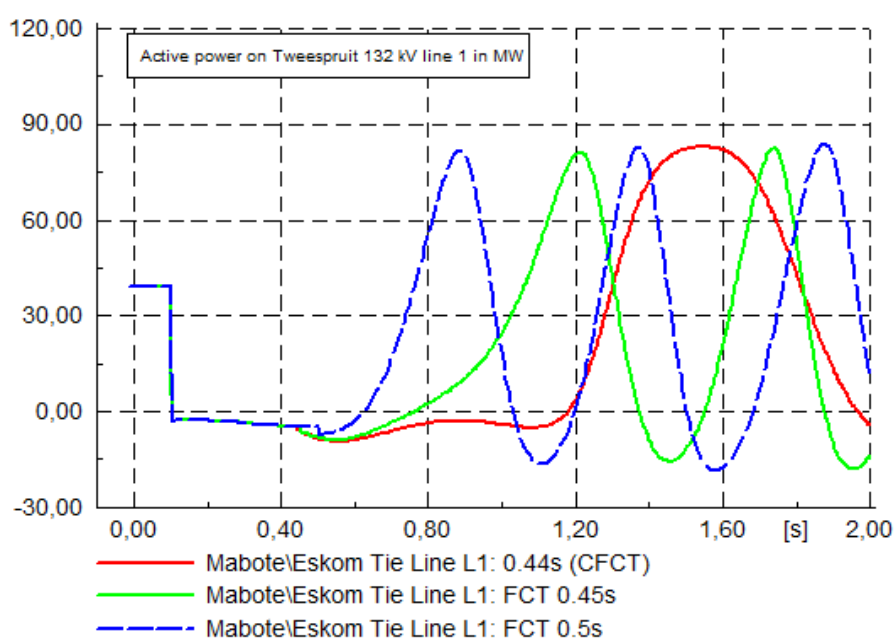
A.4-1-3: Excitation voltage response



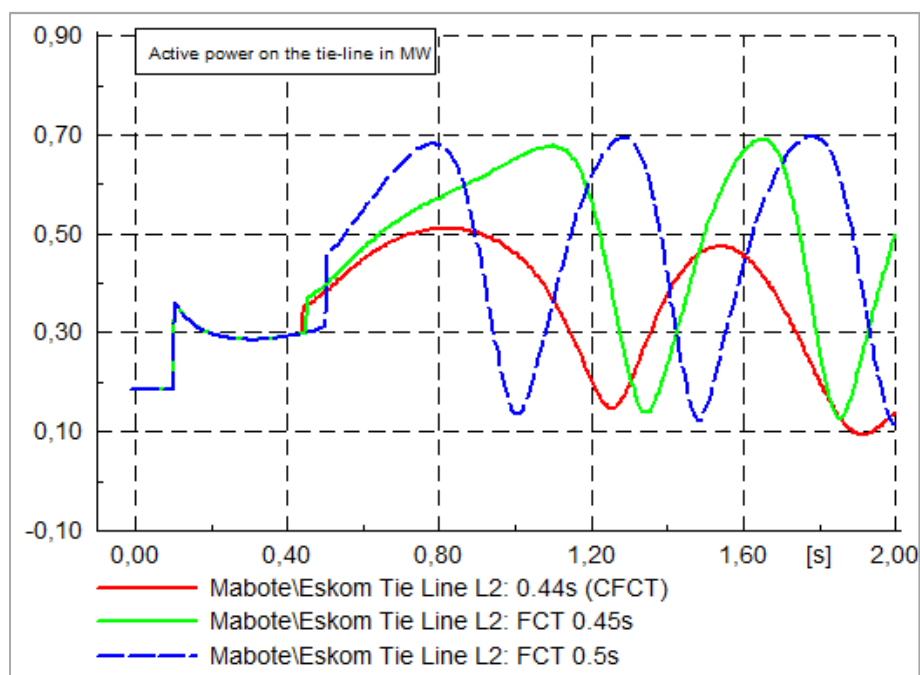
A.4-1-4: Voltage characteristics at the Mabote 132 kV busbars



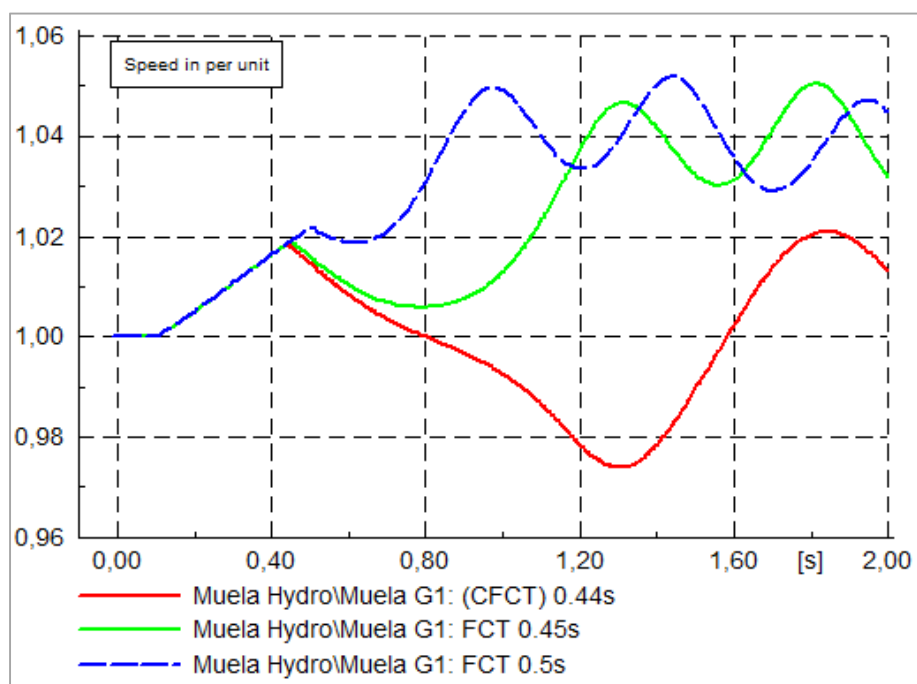
A.4-1-5: Active power on tie-line 1



A.4-1-6: Active power on tie-line 2



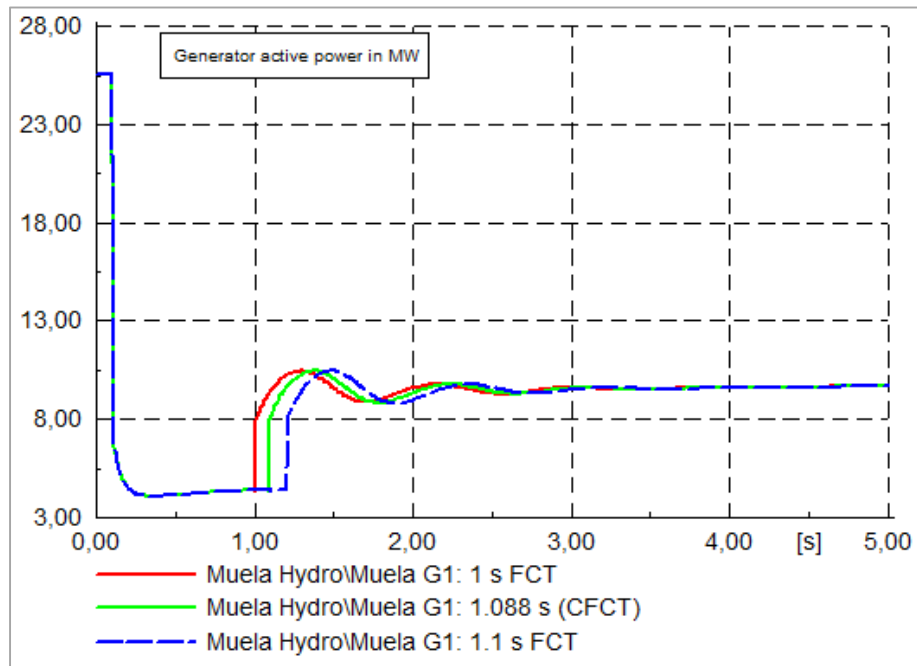
A.4-1-7: Generator speed



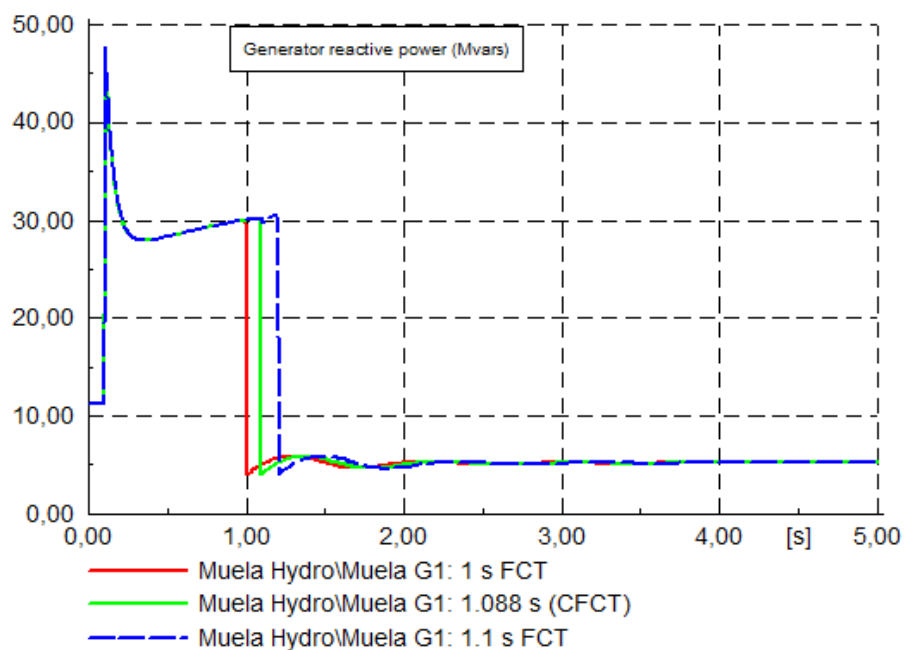
A.4-2

A fault was applied at 0.1 s and tripped at 1s, 1.088 s, and 1.1 s. The scans show the synchronous generators' active and reactive power, busbar voltage, generators' speed, active and reactive power on the Tweespruit transmission line 1.

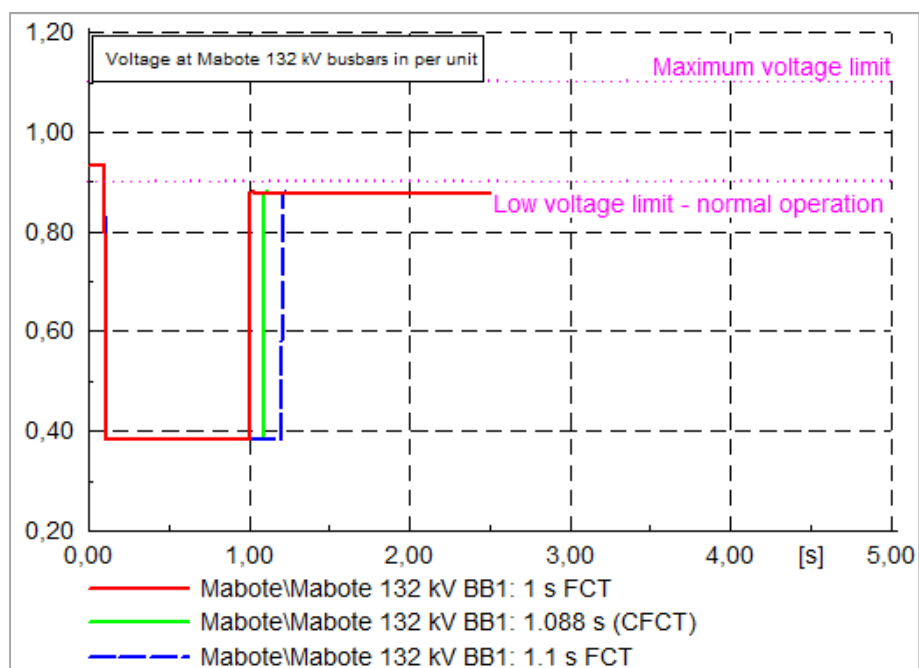
A.4-2-1: Active power



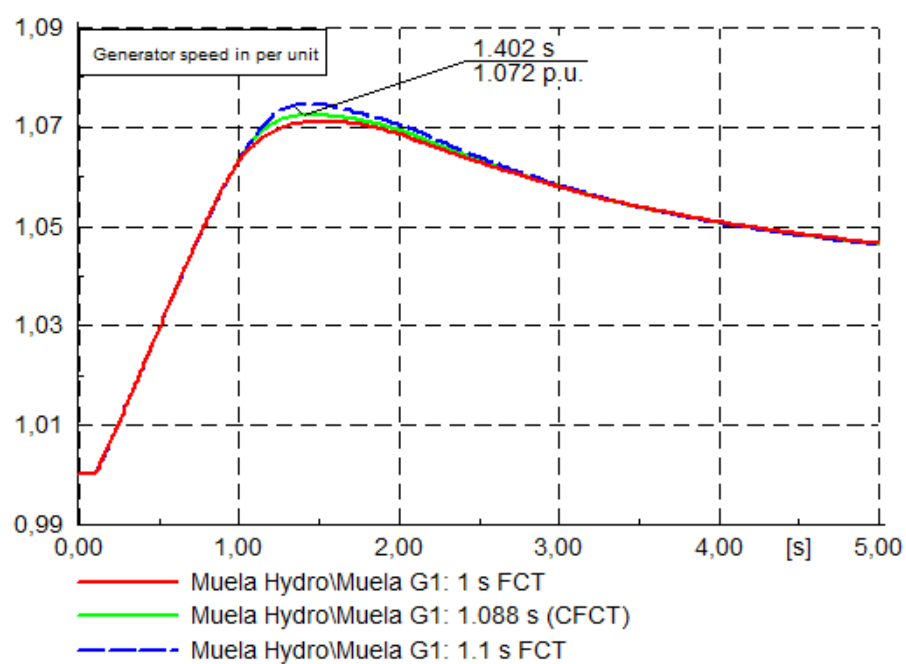
A.4-2-2: Reactive power



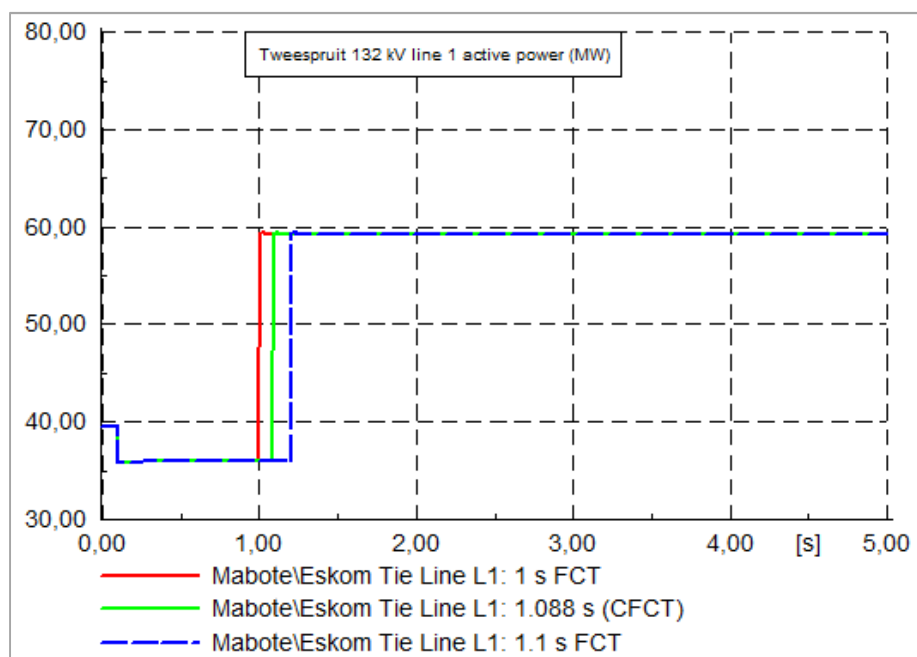
A.4-2-3: Voltage at the Mabote 132 kV busbars



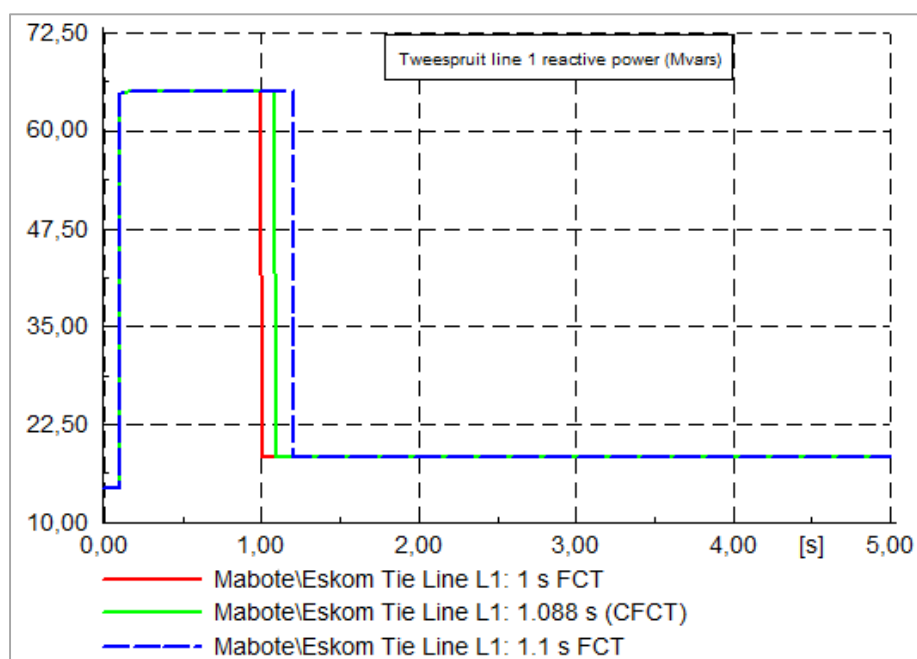
A.4-2-4: Generator speed in per unit



A.4-2-5: Active power (MW) response on Tweespruit line 1



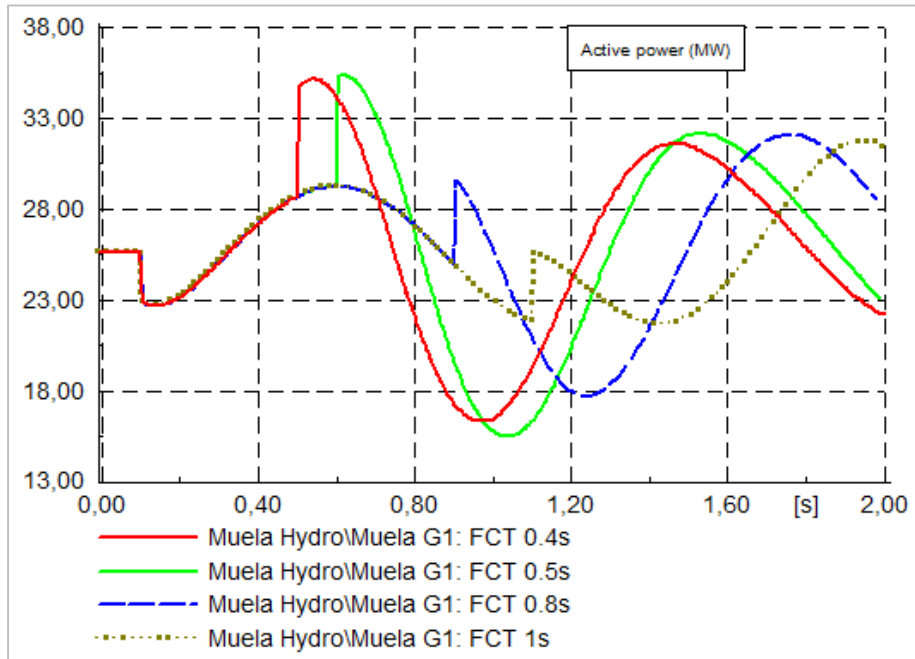
A.4-2-6: Reactive power (MW) response on Tweespruit line 1



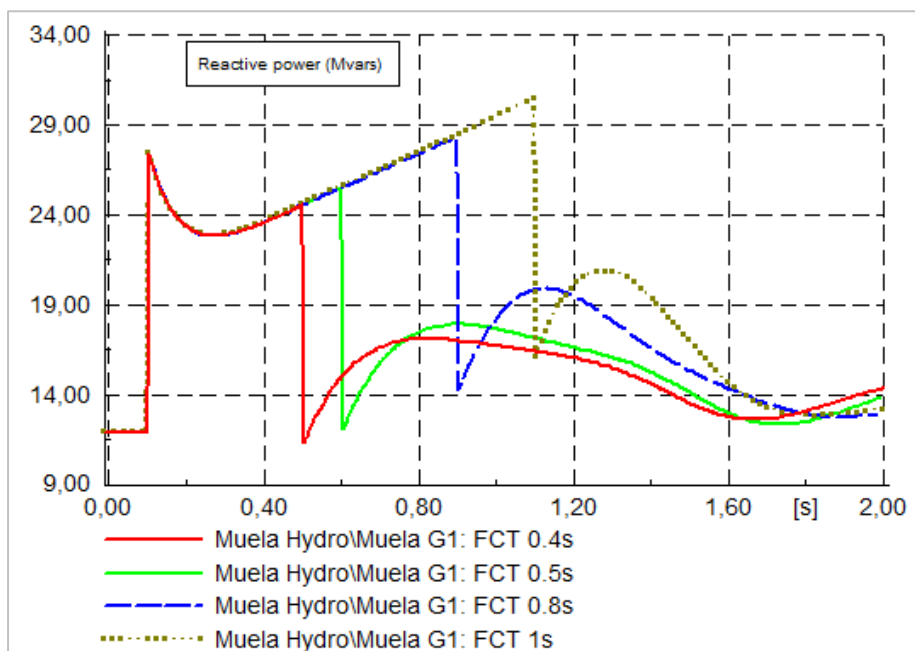
A.4-3

A fault was applied at 0.1 s and tripped at 0.5s, 0.6 s, 0.9 s and 1.1 s. The scans show the synchronous generators' active and reactive power, voltage at the Mabote busbars, rotor angle with reference to bus voltage, and frequency.

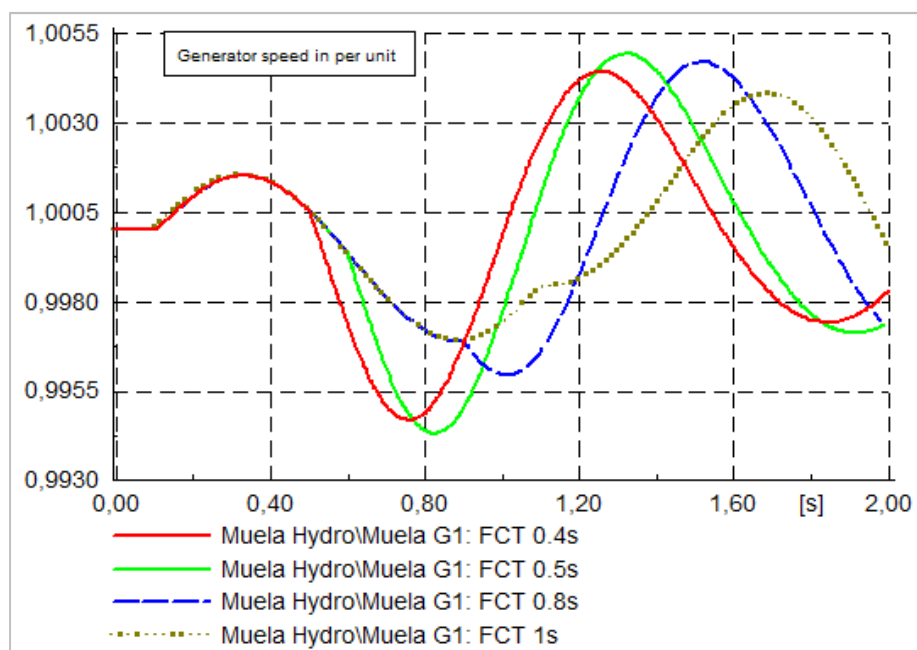
A.4-3-1: Active power



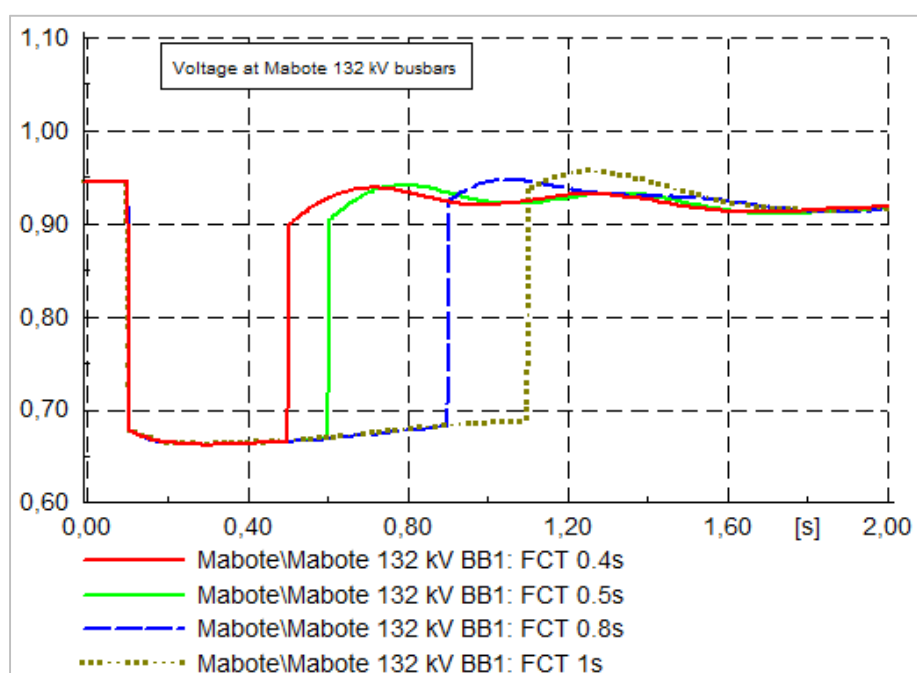
A.4-3-2: Reactive power



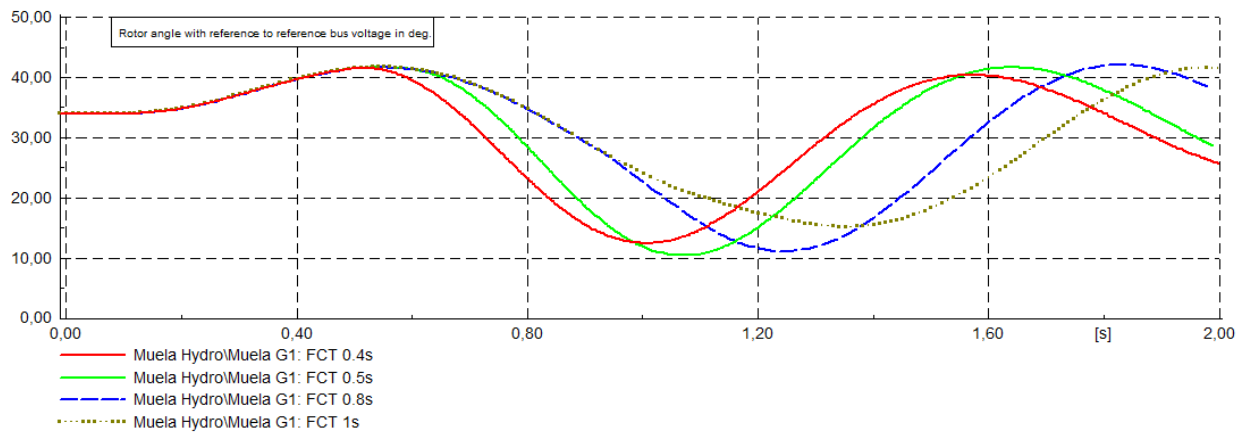
A.4-3-3: Generator speed



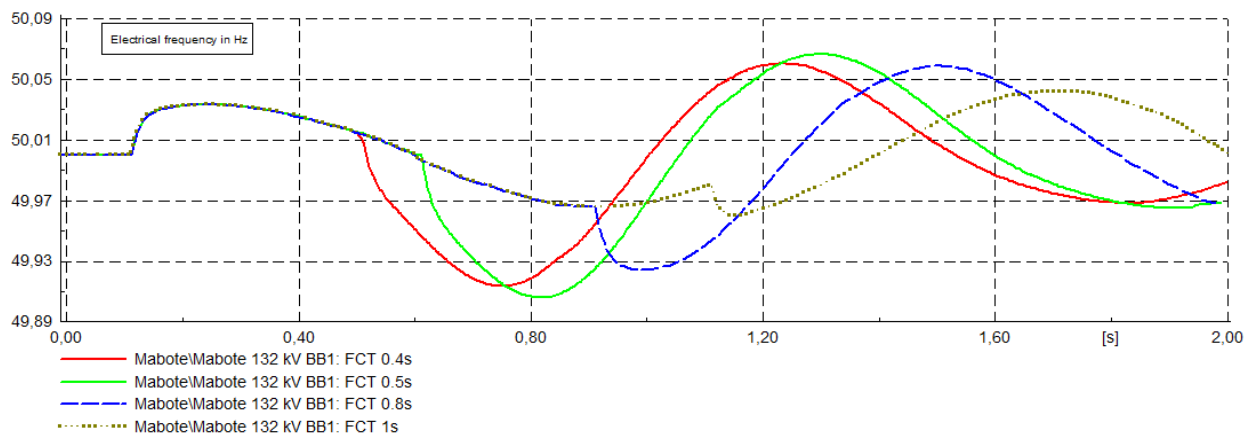
A.4-3-4: Voltage characteristics at the Mabote 132 kV busbars



A.4-3-5: Rotor angle characteristics



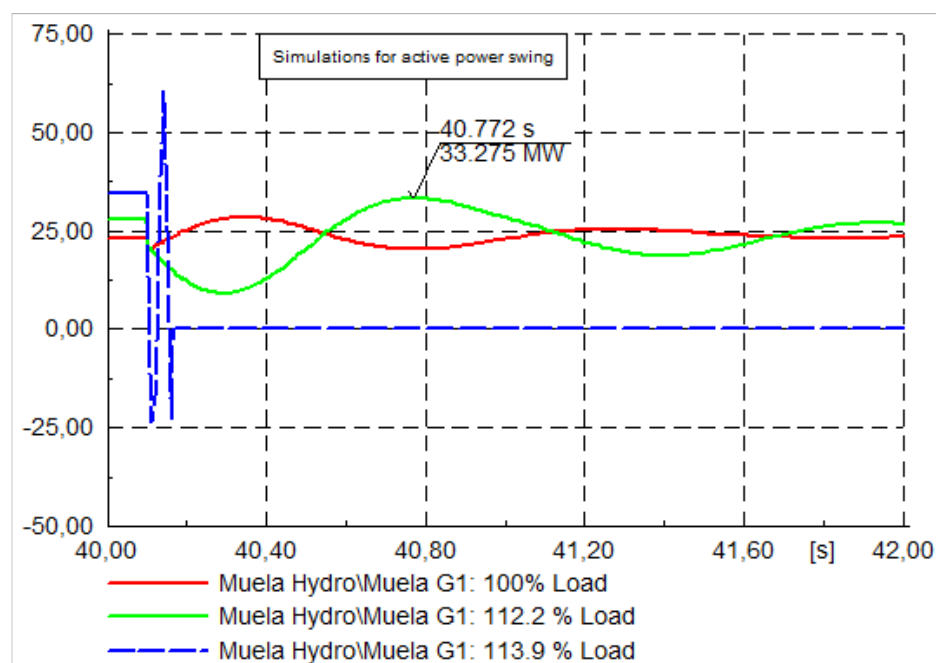
A.4-3-6: Frequency in Hz characteristics at the Mabote 132 kV busbars



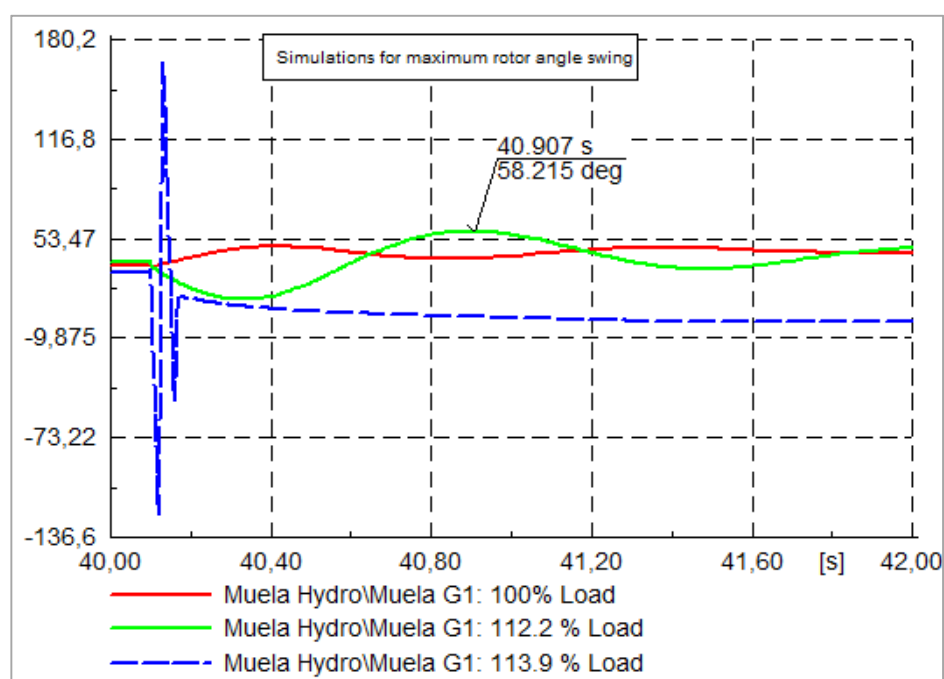
Annexure 5: The simulation results for the requisition of synchronism in the grid

The additional simulation scans show the active power swing, maximum rotor angle swing and the voltage load angle across the open breaker poles prior to resynchronising for different load conditions. A.5-5 presents the combination of loads restored to simulate the system loading prior to the tie-line breaker closing action to resynchronise the two systems.

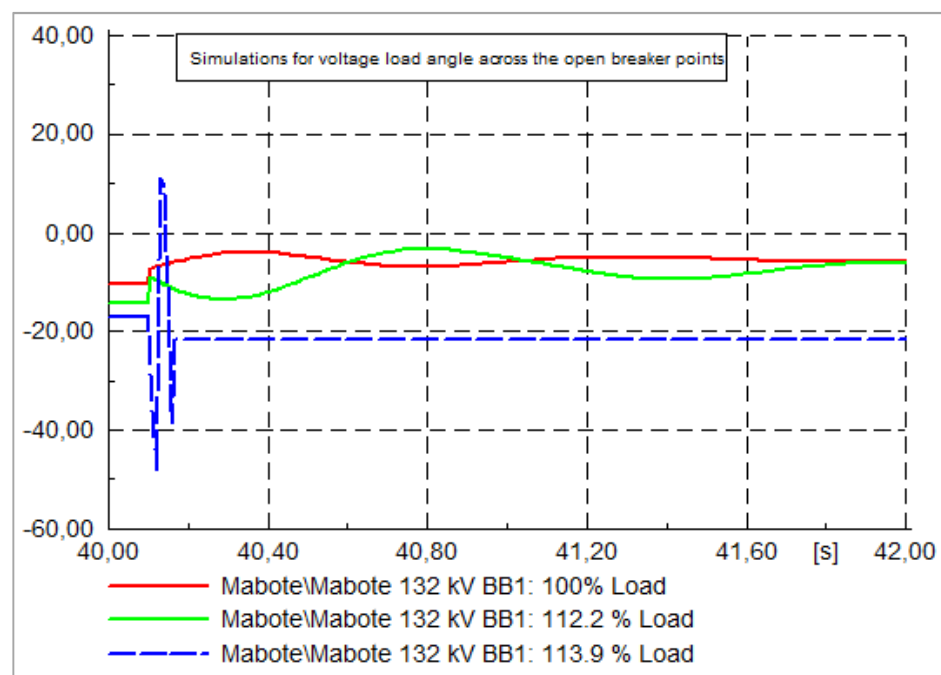
A.5-1: Simulations for active power swing



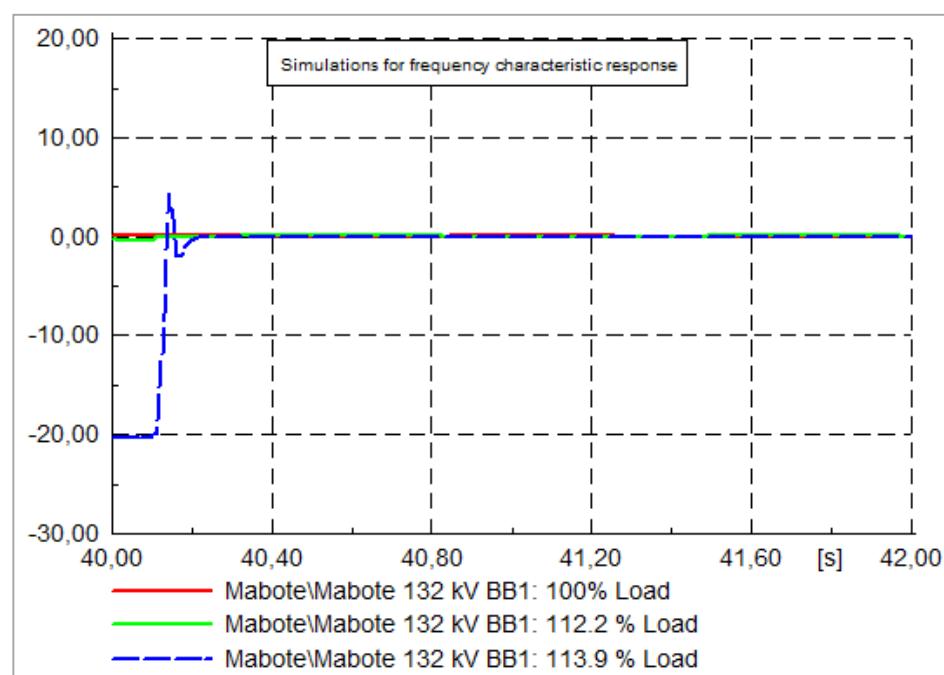
A.5-2: Simulations for maximum rotor angle swing



A.5-3: Simulations for voltage load angle across the open breaker points



A.5-4: Simulations for frequency characteristic response



A.5-5: Combination of loads restored to simulate the different system loading conditions prior to closing the tie-line breaker, thus synchronising the two systems.

	Case 0	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
St Agnes	-	3,78	3,78	3,78	3,78			
Mazenod			2,44					
Tsosane				4,06			4,06	
Muela					4,67	4,67	4,67	
Litsoeneng								9,85
Ramarothole						3,84		
Total loads restored (MW)	-	3,78	6,22	7,84	8,45	8,51	8,73	9,85