ANALYSIS OF OPTIONS TO LIMIT OCCURRENCE AND DURATION OF UNDER FREQUENCY LOAD SHEDDING IN SMALL, RENEWABLE-DOMINANT POWER SYSTEMS: THE CASE OF SRI LANKA

M.G.N.D. Hemachandra

168513U

Degree of Master of Science

Department of Electrical Engineering

University of Moratuwa
Sri Lanka

March 2021

ANALYSIS OF OPTIONS TO LIMIT OCCURRENCE AND DURATION OF UNDER FREQUENCY LOAD SHEDDING IN SMALL, RENEWABLE-DOMINANT POWER SYSTEMS: THE CASE OF SRI LANKA

M.G.N.D. Hemachandra

168513U

Thesis/Dissertation submitted in partial fulfillment of the requirements for the degree of Master of Science in Electrical Engineering

Department of Electrical Engineering

University of Moratuwa
Sri Lanka

March 2021

DECLARATION OF THE CANDIDATE & SUPERVISORS

“I declare that this is my own work and this thesis/dissertation does not incorporate without acknowledgement any material previously submitted for a Degree or Diploma in any other University or institute of higher learning and to the best of my knowledge and belief it does not contain any material previously published or written by another person except where the acknowledgement is made in the text.

Also, I hereby grant to University of Moratuwa the non-exclusive right to reproduce and distribute my thesis/dissertation, in whole or in part in print, electronic or other medium. I retain the right to use this content in whole or part in future works (such as articles or books).

………………………….. ………………………..

Signature

(M.G.N.D. Hemachandra)

Date

The above candidate has carried out research for the Masters thesis/
Dissertation under my supervision.

…………………………... ……………………...

Signature of the supervisor Date

(Dr. W.D.A.S. Rodrigo)

…………………………… ..……………………

Signature of the supervisor Date

(Dr T. Siyambalapitiya)

ACKNOWLEDGEMENTS

Foremost, I would like to express my sincere gratitude to my supervisors Dr. W.D.A.S. Rodrigo and Dr. T. Siyambalapitiya for the continuous support during the research, for the motivation and the immense knowledge shared for the accomplishment of goals. Their guidance aided me during the research and during the writing of the thesis.

Besides my supervisors, I would like to thank all the lecturers in Department of Electrical Engineering, University of Moratuwa for their encouragement, insightful comments and suggestions during the progress reviews of the research which shaped the work to be meaningful.

My sincere thanks also go to my colleagues and superiors at my working place for their encouragement and support given during hard times to reach this milestone.

Last but not the least, I would like to thank my family: my wife Erandi, my children Nisandu and Nethuli, my parents and my parents in law for their immense support given throughout the course of the research.

ABSTRACT

The power system Sri Lanka is an islanded power system of a relatively small size. Other than the coal power plants, combined cycle plants and gas turbines, a significant portion of electricity requirement is supplied by large hydro, mini hydro and other non-conventional renewable energy power plants. Accordingly, the power system of Sri Lanka can be identified as a low-inertia power system.

CEB, the power transmission operator of Sri Lanka, adheres to N-1 reliability in the transmission network. They are not expected to keep N-1 reliability in generation according to the current practice. It means that the internationally practiced power system reliability levels do not exist in the power system Sri Lanka.

Even before Non-Conventional Renewable Energy (NCRE) additions, the power system was largely dependent on under-frequency load shedding (UFLS) after large generator disconnection. Introducing NCRE to the power system has worsened the situation further.

The aim of the study was to identify the behavior of the power system of Sri Lanka during and after generation disconnection and study possible methods to improve the power system performance after generation disconnection event. The impact of battery energy storage systems on frequency response was studied for the power system of Sri Lanka. A cost analysis on battery energy storage system was performed. Increase in costs was also calculated if an internationally practiced level of spinning reserve is maintained in the power system Sri Lanka. Suggestions to improve the performance of the system are included in the thesis, based on the findings of the research.

Key word: BESS, CBEST, spinning reserve, UFLS, PSS/E

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF ABBREVIATIONS

Abbreviation	Description
ac	Alternating current
AEMO	Australian Energy Market Operator Limited
BESS	Battery Energy Storage System
BOP	Balance of Plant
C&C	Construction and Commissioning
CAISO	California Independent System Operator
CC	Combined Cycle
CCP	Combined Cycle plant
CEB	Ceylon Electricity Board
dc	Direct Current
EIA	Energy Information Administration
EMS	Energy Management System
ENS	Energy Not Served
EPC	Engineering, Procurement and Construction
EPRI	Electric Power Research Institute
FACTS	Flexible Alternating Current Transmission System
GT	Gas turbine
GWh	Giga watthour
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
KPS	Kelanitissa Power Station
kWh	Kilo watthour
LCOS	Levelized Cost of Storage
Li-ion	Lithium-ion
LNG	Liquified Natural Gas
LVPS	Lakvijaya Power Station
MCM	Million Cubic Meters
Mvar	Mega voltampere reactive

MW	Mega watt
MWh	Mega watthour
NCRE	Non-Conventional Renewable Energy
NIPSCO	Northern Indiana Public Service Company
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
ORE	Other Renewable Energy
PCS	Power Conversion System
PNNL	Pacific Northwest National Laboratory
PSE	Battery Storage Information
PSS/E	Power System Simulator for Engineers
PV	Photovoltaic
PYSERDA	New York State Energy Research and Development Authority
ROCOF	Rate of Change of Frequency
UFLS	Under Frequency Load Shedding
USA	United States of America
WCP	West Coast Power

CHAPTER 1

1 INTRODUCTION

1.1 Background

Most countries today aim for higher reliability in their power systems. They maintain and operate their power systems so that a credible event in the power system will not affect consumers of electricity. Reliability of the power system has a monetary value in the modern world. One criterion for making investment decisions on industries and business in a country, is the reliability of electricity supply. Investors tend to shift their businesses to countries which have highly reliable power systems. Policies related to reliability of the power system are analyzed regularly and necessary amendments are done considering the criticality of the quality and availability of electricity to consumers.

1.2 The case of the world

Australian Energy Market Operator ltd (AEMO) is the entity responsible for operating Australian power system and for maintaining the power system security. They operate the system such that, during a credible event, the electricity supply to consumers should not be interrupted and the power system is in a secure operating state. Generally, a credible event is regarded as an unplanned disconnection of any single item of the power transmission system or in generation. Reclassification of an event as credible or non-credible contingency event is carried out when required, to adequately reflect the present and expected conditions [1]. Almost all aspects of power system operations are well defined and well documented.

According to transmission system security and planning standards of Ireland, the system shall be designed to withstand the more probable contingencies. The more probable contingencies are defined as single contingency (N-1), overlapping single contingency and generator outage (N-G-1) and double outage contingency (N-1-1) disturbances. After a probable contingency disturbance, the system should reach a steady state within emergency operating limits [2].

In Armenian electricity transmission security standards, contingencies are defined and they shall not have adverse impacts on consumers. A permanent fault on a transmission line, a loss of any generating unit and double circuit faults are considered as contingencies that are probable [3].

1.3 The case of Sri Lanka

The power system of Sri Lanka is an isolated power system of a relatively small capacity, with a peak demand of around 2600 MW and a daily electricity consumption around 43 GWh. About 1/3 of the electricity requirement is generated by larger hydropower plants. About 10% of the electricity requirement is supplied by the mini-hydro power plants and the other non-conventional renewable energy power plants. The power system has a higher share of low-inertia generators. Absence of large industrial loads in the power system further contributes to the low inertia behavior.

Even before non-conventional renewable energy (NCRE) additions commenced, the power system was largely dependent on under-frequency load shedding (UFLS) after disconnection of a large generator. Introducing NCREs has worsened the situation further. The conventional wind and solar PV have zero inertia support to the power system. If costs are disregarded, legacy solutions to increase the power system inertia would be to add more high inertia thermal power plants such as gas turbine generators, and to interconnect synchronously to a high inertial power system, such as India.

CEB, the power transmission operator of Sri Lanka, adheres to N-1 reliability in the transmission network. That means a single contingency in the transmission network (e.g. the disconnection of a transmission line, or a transformer) will not cause adverse effects on electricity consumers. However, with regard to generators, according to the current practice, they are not expected to maintain N-1 reliability (e.g. disconnection of one generator).

So, it is apparent that in the power system of Sri Lanka, internationally practiced power system reliability levels do not exist at generation level.

1.4 Problem definition

Today almost all industries depend on electricity. There is a high competition between countries to attract investments to their countries. One of the major concerns of the investors is the state of the power system of a country. Sri Lanka achieved 100% electrification in 2016. The next target has to be to improve the availability and the quality of the power supply. In the path toward achieving this target, the first step should be to set goals for the future by amending the power system reliability standards and practices to match internationally practiced levels. For that, the present power system and its behavior should be thoroughly studied.

This will be useful to identify the weaknesses in the power system. Then the modern methods and technologies to tackle these issues can be studied. If a good power system reliability practice is to be implemented in the next few years, it is appropriate to analyze possible methods of reducing impacts due to low inertia and minimize impacts of generation outages on consumers.

1.5 Research objectives

(a) Analyze the behavior of the power system of Sri Lanka during generation-related disturbances and analyze the possibility of reducing the impact on consumers after such disturbances.

(b) Analyze and discuss the costs of implementing the methods to improve power system performance after generation-related disturbances.

1.6 Methodology

Study the power system behavior during disconnection of larger generators

1. Develop the model for the present power system of Sri Lanka in PSS/E[1] and validate the model.
2. Perform simulations and observe the system response after varying total system generation and the amount of generation disconnection
3. Model inverter and converter-based generation and simulate the response to generator disconnections

Study the possible methods to reduce impacts of large generator disconnections and to reduce the duration of electricity interruptions

---

[1] Power System Simulator for Engineers

1. Model possible future battery energy storage systems and simulate their performance during generator disconnections
2. Analyze costs of battery energy storage systems
3. Analyze costs of maintaining internationally practiced levels of spinning reserve
4. Discuss the results of the research and present recommendations

1.7 Outline of the thesis

The organization of the research is described in this section.

CHAPTER 2: A literature review for the study is presented in this chapter.

CHAPTER 3: The behavior of the power system of Sri Lanka during generation disconnections was analyzed and presented in this chapter.

CHAPTER 4: The effect of inverter, converter-based generation on the frequency response during generation disconnection was analyzed for the power system Sri Lanka, and presented in this chapter.

CHAPTER 5: The impact of battery energy storage systems on frequency response during generation disconnection was analyzed for the power system of Sri Lanka, and presented in this chapter.

CHAPTER 6: The analysis of costs of battery energy storage systems are presented in this chapter.

CHAPTER 7: A case study to identify additional costs if the spinning reserve is kept at the size of the largest generator connected, is presented in this chapter.

CHAPTER 8: Summary and conclusion, recommendation and recommendation for the future work are presented in this chapter.

CHAPTER 2

---

2 LITERATURE REVIEW

In this chapter, some studies carried out on the power system behavior and some studies carried out on BESS will be discussed. The aim of this chapter is to give an overview of these studies, to describe the usefulness of these studies and to identify the research gap.

2.1 Studies carried out on the power system behavior during generation disconnections

The maximum possible loading capacity of a single generator that will not violate the operational frequency and voltage limits for the power system of Sri Lanka have been discussed in [13]. In this study, the author has carried out case studies separately for hydro maximum, thermal maximum and extreme thermal maximum scenarios. The software used for developing the model is PSS/E. The model has been validated with actual incidents of generator disturbances. Based on observations of [13], 22%, 26% and 25% of maximum loading from a single generator can be allowed respectively for hydro maximum, thermal maximum and extreme thermal maximum scenarios. To elaborate this further, if the total system generation is 1000 MW, up to 250 MW can be loaded from a single generator during extreme thermal maximum condition. In that case, operational frequency and voltage limits will not be violated for any single generator disconnection.

Though maximum loading limits from single generator proposed in [13] are useful, it has considered UFLS operation as a normal operation during generation disconnections. It is fair enough because it is in line with the current practice of power system operation in Sri Lanka.

A new UFLS scheme for power system of Sri Lanka has been proposed based on PSCAD simulations which can improve the maximum loading capacity from single generator in [17]. It is an important study which will enable better utilization of low-cost coal power plants in Sri Lanka.

As a part of the study in [15], inertia constant for the power system of Sri Lanka has been calculated using the conventional method. In this approach, the author has considered the inertia support from generators only.

As a part of the study in [14], the author has calculated the inertia constant for the power system of Sri Lanka using the measured transient analysis. In this approach, the support from frequency dependent loads for the inertia has also been considered. The author has calculated inertia constants, damping constants and the system frequency bias as well.

The parameter calculated in [14], [15] are very useful to understand the behavior of the power system during generation disconnections. These parameters can be compared with parameters of large power systems to understand the condition of the power system of Sri Lanka in terms of power system stability.

2.2 Studies carried out on battery energy storage systems

Distributed BESS systems at distribution transformer level for Sri Lanka have been studied in [20]. This study has mainly focused on peak shaving. It has discussed benefits of BESS such as load leveling, distribution investment deferral, power quality, reliability improvement, possible emission reduction and etc. According to the cost-benefit analysis, the project has a negative net present value in 2015 due to high cost of BESS systems. It has only considered direct monetary savings for the cost-benefit analysis. Accordingly, using BESS for peak shaving is not economical in 2015. However, it should be noted that BESS prices have gone down significantly since 2015. Usage of BESS as a fast frequency reserve has not been considered in [20].

Dynamic studies on BESSs have been carried out using CBEST battery energy storage model in [21], [22]. These studies mainly focused on increasing the utilization of wind generation using BESSs.

2.3 Research gap identification

In studies on power system behavior during generation disconnections, methods that can reduce UFLS operation and methods to reduce the duration after an UFLS event have not been studied. An analysis on costs of these methods is also important. Studies should be carried out to identify methods to reduce impacts from generation disconnections and to understand costs of these methods.

Studying impacts of NCRE penetration on the frequency response during generation disconnections is also important.

In studies on BESS systems for the power system of Sri Lanka, the dynamic behavior of BESSs has not been considered. It has considered BESSs for the peak shaving purpose only. BESS technologies have been evolving rapidly so that it can be used as a fast frequency reserve and as a static inertia reserve. A cost analysis has not been performed for the usage of BESS as a fast frequency reserve. On the other hand, costs of batteries have been reducing significantly and it is important to initiate a cost study on BESS. No recent studies on utility scale BESSs for the power system of Sri Lanka were found in literature.

In countries where spinning reserves are purchased, the cost for spinning reserve can be calculated easily. Finding costs of spinning reserve is not direct for the power system of Sri Lanka since we do not purchase spinning reserves. However, these spinning reserve costs should be studied in order to implement power system reliability standards for Sri Lanka. No literature was found on spinning reserve costs for the power system of Sri Lanka.

3 THE POWER SYSTEM BEHAVIOR DURING GENERATOR DISCONNECTIONS

3.1 Modelling the present power system

The power system of Sri Lanka was modelled to simulate its behavior during generator disconnections. PSS/E [6] was used to develop the power system model as at September 2019. Parameters for modelling were obtained from dispatch models of 2016 and 2025 (forecast) available at the National System Control Centre, Ceylon Electricity Board. The present power system model should be validated using actual generator-related disturbances which will improve the accuracy of simulations of the research.

During steady state modelling, bus bars, transformers, transmission lines, shunt devices, loads, and generators were modelled with their parameters. In this modelling two files were updated

1. Network data file – contains names, associations and parameters in tabular form (See figure 3-1)
2. Single line diagram file – contains the graphical view of components and their interconnections (See figure 3-2)

Bus Number	Bus Name	Base kV	Area Num	Area Name	Zone Num	Zone Name	Owner	Owner Name	Code	Voltage (pu)	Angle (deg)	Normal Vmax (pu)	Normal Vmin (pu)	Emergency Vmax (pu)	Emergency Vmin (pu)
1100	LAX-1	132.0	2		1		1		-2	0.9998	-6.67	1.1000	0.9000	1.1000	0.9000
1101	LAX_DUMMY	132.0	2		1		1		1	0.9998	-6.67	1.1000	0.9000	1.1000	0.9000
1110	N-LAX-1	132.0	2		1		1		1	1.0001	-6.67	1.1000	0.9000	1.1000	0.9000
1120	WIMAL-1	132.0	2		1		1		-2	0.9994	-6.71	1.1000	0.9000	1.1000	0.9000
1130	POLPI-1	132.0	2		1		1		-2	0.9968	-6.71	1.1000	0.9000	1.1000	0.9000
1140	CANYO-1	132.0	2		1		1		-2	1.0011	-6.54	1.1000	0.9000	1.1000	0.9000
1150	AMPA-1	132.0	3		1		1		1	1.0031	-7.59	1.1000	0.9000	1.1000	0.9000
1160	INGIN-1	132.0	3		1		1		1	1.0035	-7.39	1.1000	0.9000	1.1000	0.9000
1170	SAMAN-1	132.0	1		1		1		-2	1.0129	-6.50	1.1000	0.9000	1.1000	0.9000
1200	UKUWE-1	132.0	4		1		1		-2	0.9330	-12.06	1.1000	0.9000	1.1000	0.9000
1201	UKUWE-2	132.0	1		1		1		1	0.9330	-12.06	1.1000	0.9000	1.1000	0.9000
1210	BOWAT-1	132.0	7		1		1		-2	0.9334	-12.07	1.1000	0.9000	1.1000	0.9000
1240	VAVUN-1	132.0	4		1		1		1	1.0234	1.47	1.1000	0.9000	1.1000	0.9000
1250	RANTE-1	132.0	5		1		1		1	1.0021	-4.93	1.1000	0.9000	1.1000	0.9000
1260	MAHIYANGAN 1	132.0	1		1		1		1	1.0022	-5.42	1.1000	0.9000	1.1000	0.9000
1270	COL_M1	132.0	1		1		1		1	1.0049	0.12	1.1000	0.9000	1.1000	0.9000
1285	COL_N1	132.0	1		1		1		1	1.0114	-3.10	1.1000	0.9000	1.1000	0.9000
1300	KELAN-1	132.0	6		1		1		-2	1.0133	-2.93	1.1000	0.9000	1.1000	0.9000
1310	SAPUG-1P	132.0	6		1		1		1	1.0146	-1.19	1.1000	0.9000	1.1000	0.9000
1320	NAULA-1	132.0	1		1		1		1	0.9310	-12.31	1.1000	0.9000	1.1000	0.9000
1330	MONARA-1	132.0	1		1		1		1	1.0015	-6.79	1.1000	0.9000	1.1000	0.9000
1340	BEATT-1	132.0	1		1		1		1	1.0214	-5.82	1.1000	0.9000	1.1000	0.9000
1350	COL_L1	132.0	1		1		1		1	1.0049	0.12	1.1000	0.9000	1.1000	0.9000
1400	HAMBA-1	132.0	1		1		1		1	1.0218	-5.41	1.1000	0.9000	1.1000	0.9000
1410	KUKULE-1	132.0	8		1		1		2	1.0100	-5.03	1.1000	0.9000	1.1000	0.9000
1420	HORANA_1	132.0	8		1		1		1	1.0088	-5.13	1.1000	0.9000	1.1000	0.9000
1430	COL_I_1	132.0	8		1		1		1	1.0101	-3.29	1.1000	0.9000	1.1000	0.9000
1431	COL I DUM	132.0	1		1		1		1	1.0112	-3.12	1.1000	0.9000	1.1000	0.9000

Figure 3-1: A snapshot of network data tables

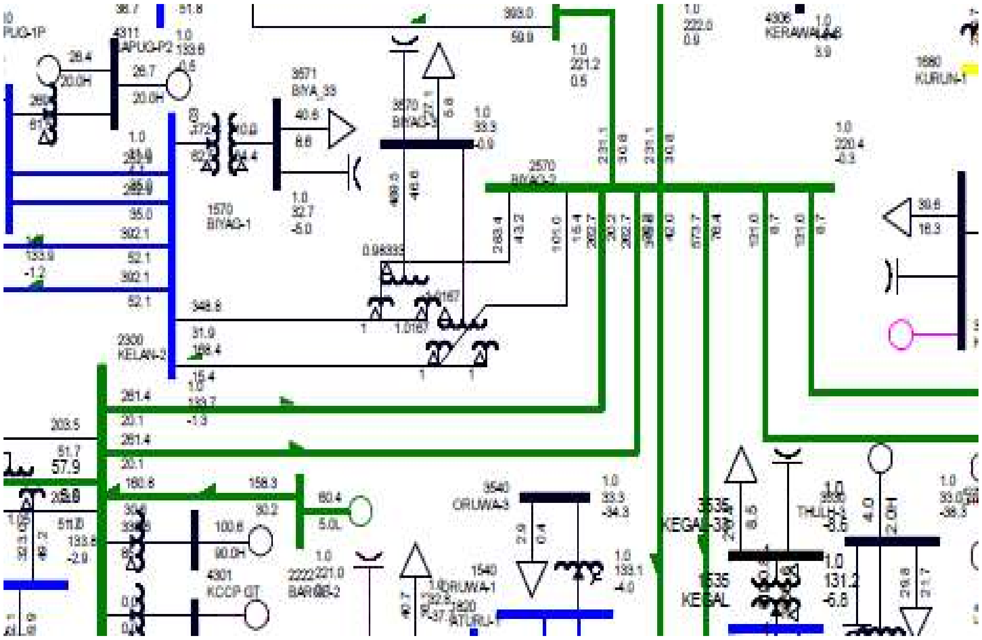
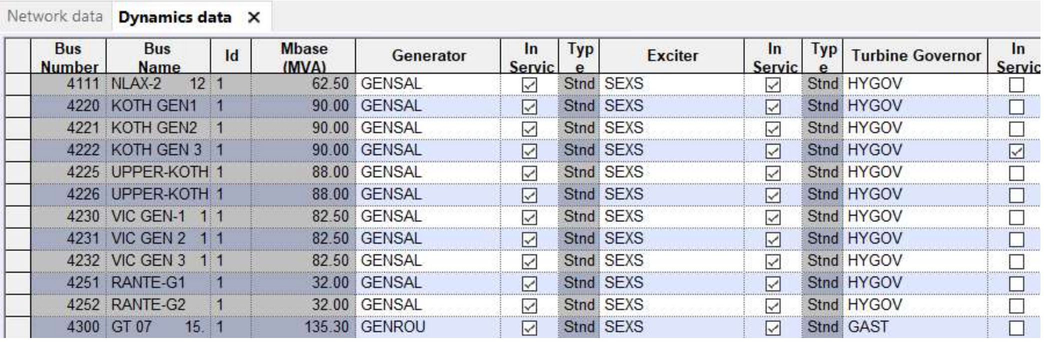


Figure 3-2: A snapshot of a part of the single line diagram

During dynamic modelling of the power system, dynamic parameters of network components were defined. In addition to the network data file and the single line diagram file, a dynamic data file was created for this purpose (See figure 3-3). The dynamic data file specifies generator models (e.g. GENSAL, GENROU), exciter models (e.g. SCRX, EXST1, IEEET1), turbine-governor models (e.g. HYGOV, GAST), load models (e.g. CLODAL), under frequency load shedding models (e.g. LDSHBL, DLSHBL), FACTS device models (e.g. CSTCNT) and the other models related to wind, solar, battery, transformer and auxiliary signals, etc.



Bus Number	Bus Name	Id	Mbase (MVA)	Generator	In Servic	Type	Exciter	In Servic	Type	Turbine Governor	In Servic
4111	NLAX-2 12	1	62.50	GENSAL	☑	Stnd	SEXS	☑	Stnd	HYGOV	☐
4220	KOTH GEN1	1	90.00	GENSAL	☑	Stnd	SEXS	☑	Stnd	HYGOV	☐
4221	KOTH GEN2	1	90.00	GENSAL	☑	Stnd	SEXS	☑	Stnd	HYGOV	☐
4222	KOTH GEN 3	1	90.00	GENSAL	☑	Stnd	SEXS	☑	Stnd	HYGOV	☑
4225	UPPER-KOTH	1	88.00	GENSAL	☑	Stnd	SEXS	☑	Stnd	HYGOV	☐
4226	UPPER-KOTH	1	88.00	GENSAL	☑	Stnd	SEXS	☑	Stnd	HYGOV	☐
4230	VIC GEN-1 1	1	82.50	GENSAL	☑	Stnd	SEXS	☑	Stnd	HYGOV	☐
4231	VIC GEN 2 1	1	82.50	GENSAL	☑	Stnd	SEXS	☑	Stnd	HYGOV	☐
4232	VIC GEN 3 1	1	82.50	GENSAL	☑	Stnd	SEXS	☑	Stnd	HYGOV	☐
4251	RANTE-G1	1	32.00	GENSAL	☑	Stnd	SEXS	☑	Stnd	HYGOV	☐
4252	RANTE-G2	1	32.00	GENSAL	☑	Stnd	SEXS	☑	Stnd	HYGOV	☐
4300	GT 07 15.	1	135.30	GENROU	☑	Stnd	SEXS	☑	Stnd	GAST	☐

Figure 3-3: A snapshot of dynamic data tables

3.2 Model Validation for the present power system

Once the present power system was modelled in PSS/E, the model should be validated by simulating actual generator disconnections on the developed model. Two actual cases were selected to validate the model.

1. Disconnection of 130 MW of West Coast Power (WCP) generation on 17 Jul 2019 at 9:19 hrs.
2. Disconnection of 200 MW of Lakvijaya Power Station (LVPS) unit 03 generation on 21 Dec 2019 at 21:10 hrs.

For each case, the model was validated in steady state and then the model was validated in a dynamic simulation.

3.2.1 Disconnection of 130 MW of WCP generation

At the time of the incident, the total system generation was 1954 MW and 345 Mvar. The plant-wise generation at the time is shown in APPENDIX A. The actual generation and loads at each grid substation were input to the model. The system was simulated in steady state and it converged to a valid solution.

Then the incident was dynamically simulated in the model, and frequency and voltage variations were taken as outputs from the simulation. The actual frequency and voltage variations were obtained from the fault recorder installed at Veyangoda grid substation.

The actual and simulated frequency variations and voltage variations were plotted in figure 3-4 and 3-5 respectively. The system has recovered with the operation of under frequency load shedding stage I in both actual incident and simulated case. A similar pattern of variation was observed in voltage even though there is a difference in the steady state voltage as shown in figure 3-5. Possible reasons for deviations will be explained in section 3.2.3.

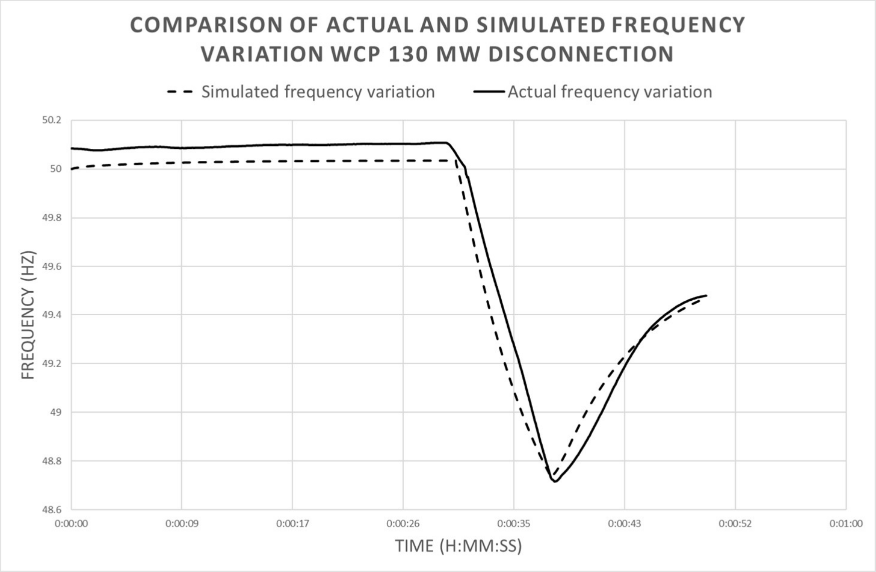


Figure 3-4: Comparison of actual and simulated frequency variations for 130 MW WCP disconnection

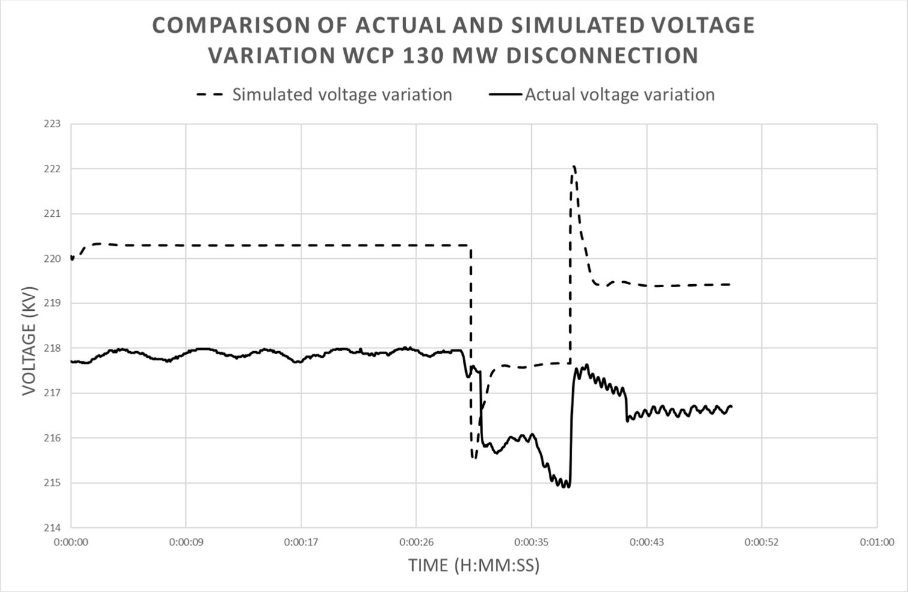


Figure 3-5: Comparison of actual and simulated voltage variation at 220 kV level for 130 MW WCP disconnection

3.2.2 Disconnection of 200 MW of LVPS unit 03 generation

At the time of the incident, the total system generation was 1770 MW and 194 Mvar. The plant-wise generation at the time is shown in APPENDIX A. The actual generation and grid-wise loads were input to the model. The system was simulated in steady state and it converged to a valid solution.

Then the incident was dynamically simulated in the model, and frequency and voltage variations were taken as outputs from the simulation. The actual frequency and voltage variations were obtained from the fault recorder installed at Veyangoda grid substation.

The actual and simulated frequency variations and voltage variations were plotted in figure 3-6 and 3-7 respectively. The system has recovered with the operation of under frequency load shedding stage II in both actual incident and simulated case. A similar pattern of variation was observed in voltage even though there is a difference in steady state voltage as shown in figure 3-7. The possible reasons for deviations will be explained in section 3.2.3

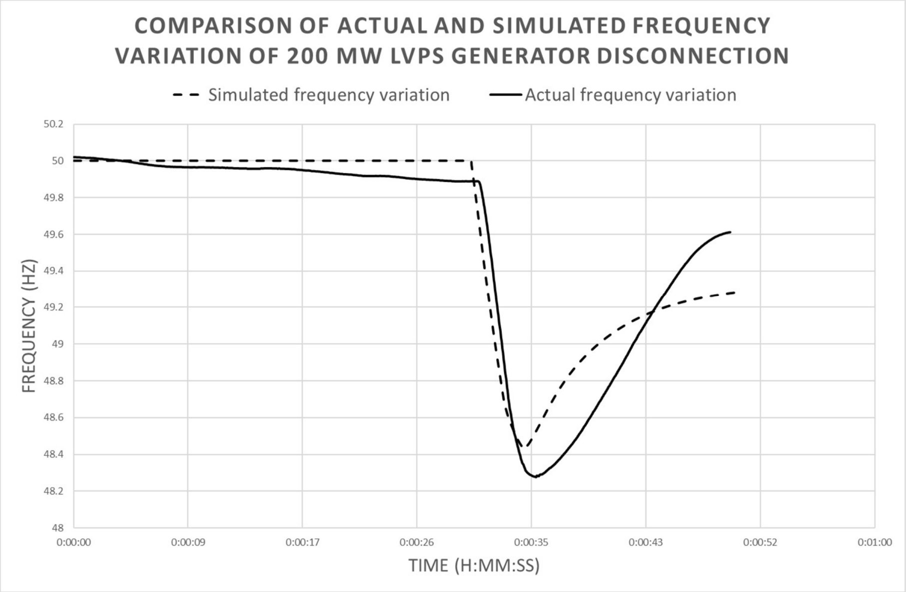


Figure 3-6: Comparison of actual and simulated frequency variation for 200 MW LVPS disconnection

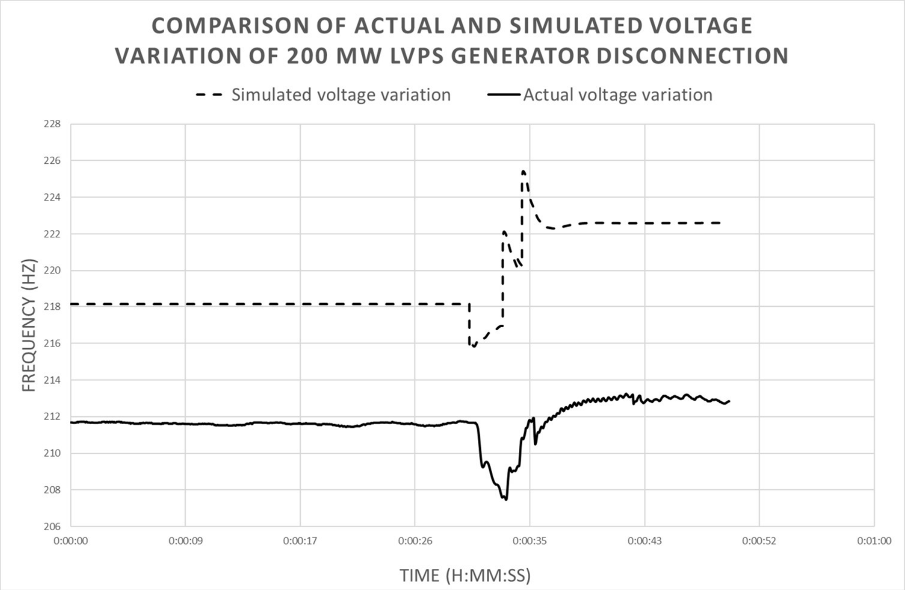


Figure 3-7: Comparison of actual and simulated 220kV voltage variation for 200 MW LVPS disconnection

3.2.3 Remarks on model validation

The deviation of the frequency and voltage in simulations from actual may be due to following reasons

1. The actual behavior of loads might be different from the simulated load model
2. The power flow in the model might be different from the actual power flow at that time
3. Actual percentages of UFLS might be different from percentages of UFLS simulated
4. NCRE connected to the grid might have responded differently to frequency variations

Although the simulated results do not match exactly with the actual results, the results from the simulations are reasonable enough to approve the developed model for the purpose of the research.

3.3 Simulation of the power system behavior for the size of generation disconnection and for the size of the power system

The aim of this series of simulations was to understand the behavior of the power system during generator disconnections, as the system demand varies. It was assumed that the load model is the same in all simulated cases.

3.3.1 Simulation example: Disconnection of 270 MW from 2000 MW of total system generation – Hydro dominant case

The simulation described here is for the hydro dominant case. The economic dispatch of generators used for the simulation is shown in APPENDIX B. Actual demand at grid substations of a hydro dominant case was scaled down to match system generation for the simulation.

The case was first simulated in steady state. In the dynamic simulation, 270 MW Lakvijaya unit 03 was disconnected and the number of under frequency load shedding stages that operated was observed. The present under frequency load shedding scheme is shown in APPENDIX C.

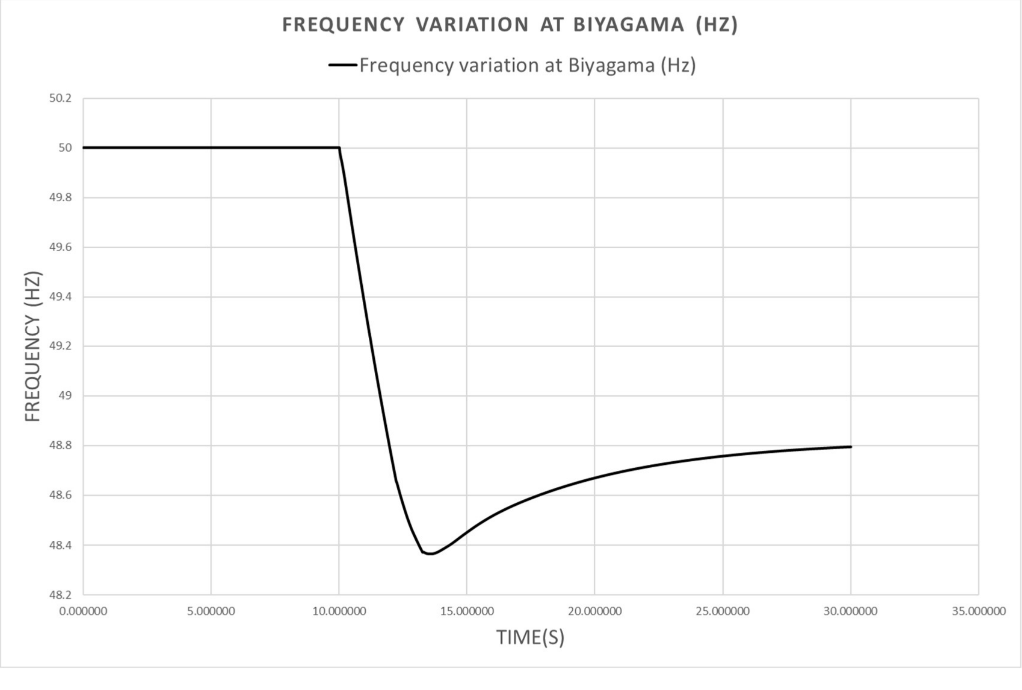


Figure 3-8: Frequency variation due to 270 MW disconnection when the total system generation was 2000 MW

Two stages of under frequency load shedding scheme have been operated before the frequency commenced the recovery as shown in figure 3-8.

3.3.2 Simulation plan

Simulation plan was executed as shown in figure 3-9, varying the total system generation and the size of the generation disconnection, using the same method used in section 3.3.1. The number of under-frequency load shedding stages operated was noted down as outputs of simulations. Simulations were carried out separately for hydro dominant and thermal dominant cases.

	Size of the generation disconnection				
Total system generation	**80 MW**	**100 MW**	**150 MW**	**200 MW**	**270 MW**
2000 MW					
2100 MW					
2200 MW					
2400 MW					
2600 MW					
2800 MW					
3000 MW					

Figure 3-9: The simulation plan for thermal dominant and hydro dominant cases

Total system generation was selected between 2000 MW and 3000 MW, considering the present generation capacity installed. Steps of size of the generation disconnection were selected as 80 ,100, 150 and 270 MW so that the start of the operation of UFLS can be distinguished while covering up to the largest generation unit size connected. All together 70 simulations were taken to identify the pattern of under frequency load shedding operation as described in section 3.3.3.

3.3.3 Simulation results

Simulations were carried out according to the simulation plan stated in the section 3.3.2. For each total system generation level, simulations were carried out by varying the size of the generation disconnected from 80 MW to 270 MW. The number of stages of UFLS operated for the hydro dominant case and for the thermal dominant case is shown in table 3-1 and table 3-2 respectively.

HYDRO DOMINANT CASE	**The size of the generation disconnection**				
Total system generation	**80 MW**	**100 MW**	**150 MW**	**200 MW**	**270 MW**
2000 MW	-	1	1	2	2
2100 MW	-	1	1	1	2
2200 MW	-	1	1	1	2
2400 MW	-	-	1	1	2
2600 MW	-	-	1	1	2
2800 MW	-	-	1	1	1
3000 MW	-	-	1	1	1

Table 3-1: Number of UFLS stages operated for hydro dominant case

THERMAL DOMINANT CASE	**The size of the generation disconnection**				
Total system generation	**80 MW**	**100 MW**	**150 MW**	**200 MW**	**270 MW**
2000 MW	-	-	1	1	2
2100 MW	-	-	1	1	2
2200 MW	-	-	1	1	2
2400 MW	-	-	-	1	2
2600 MW	-	-	-	1	1
2800 MW	-	-	-	1	1
3000 MW	-	-	-	1	1

Table 3-2: Number of UFLS stages operated for thermal dominant case

It can be clearly seen from table 3-1 and 3-2 that the frequency response for disconnection of generation is better when the dispatch is thermal dominant due to comparatively higher inertia in thermal generators (e.g. gas turbines, CC based generators).

Simulation results in table 3-1 and 3-2 indicate that the frequency response after generation disconnections improves when the size of the power system increases. However, the recovery process remains significantly dependent on the under-frequency load shedding.

When simulating without the UFLS enabled (2000MW total generation, 270 MW generator disconnection), the simulation doesn't converge. It means that the system will not survive if UFLS disabled for 270 MW generation disconnection.

4 THE EFFECT OF INVERTER/CONVERTER BASED GENERATION ON THE FREQUENCY RESPONSE

4.1 Modelling the power system for the simulations

A modified version of the power system model which can be expected in 2025 was used for simulations. Four wind parks were included in the model; three wind parks at Mannar and one wind park at Pooneryn. Their sizes are 152 MW, 152 MW, 72 MW and 127MW respectively. Parameters for the dynamic modelling of wind were obtained from Ceylon Electricity Board. Gas-fired combined cycle (CC) plants, one additional coal power plant, too were included in the model.

4.2 The cases for simulations

The objective of this part of the study was to get an insight into the frequency response during generator disconnections, as the size of the wind penetration increases. Wind penetration was varied from 0 MW to 500 MW, while keeping the total generation and the hydro generation constant for all cases. The unit-wise generation for each case is shown in the APPENDIX D. The generation mix by technology for each case is shown in table 4-1.

Table 4-1: Cases for simulations with different wind penetration

Cases for simulations	Hydro (MW)	Thermal (MW)	Wind park (MW)	Total generation (MW)
CASE 1 - No wind	800	2700	0	3500
CASE 2 - 100MW wind	800	2600	100	3500
CASE 3 - 200MW wind	800	2500	200	3500
CASE 4 - 300MW wind	800	2400	300	3500
CASE 5 - 400MW wind	800	2300	400	3500
CASE 6 - 500MW wind	800	2200	500	3500

4.3 Frequency response for 300 MW generation disconnection

For each case in table 4-1, Kerawalapitiya CC generation of size 300 MW was disconnected and the frequency response was observed. The frequency responses of all cases are compared in figure 4-1.

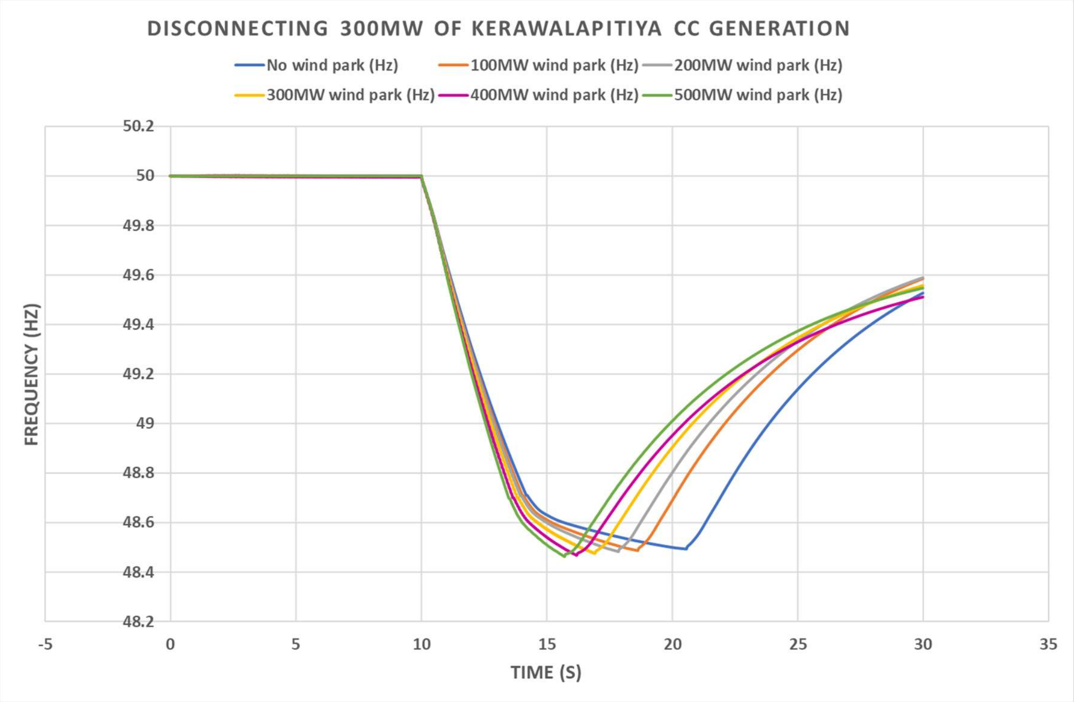


Figure 4-1: Frequency responses for a disconnection of 300 MW CC at Kerawalapitiya

In each case, the power system has recovered with the operation of under-frequency load shedding stage II. It can be clearly seen from figure 4-1 that the initial rate of change of frequency (ROCOF) increases when the wind penetration increases. The time to trigger the stage II of UFLS decreases significantly with the increase in wind penetration. Analytical results are shown in the table 4-2.

Simulation case	Minimum frequency	Time duration of frequency drop (s)	Initial average ROCOF (Hz/s)
CASE 1:No wind	48.49	10.56	0.31
CASE 2:100MW wind	48.49	8.63	0.33
CASE 3:200MW wind	48.48	7.86	0.33
CASE 4:300MW wind	48.48	6.91	0.35
CASE 5:400MW wind	48.47	6.19	0.36
CASE 6:500MW wind	48.46	5.70	0.38

Table 4-2: Results of 300 MW generation disconnection

The time duration to trigger under-frequency load shedding stage II has dropped to 5.7s in the 500 MW wind case, compared with 10.56s in the no-wind case. ROCOF increased to 0.38 Hz/s in the 500 MW wind case, from 0.31 Hz/s in no-wind case.

4.4 Frequency response for 130 MW generation disconnection

For each case in table 4-1, Kotmale generation of size of 130 MW was disconnected. For this simulation, the UFLS was disabled so the actual frequency nadir due to generation disconnection can be observed. The frequency responses of all cases are plotted together in figure 4-2.

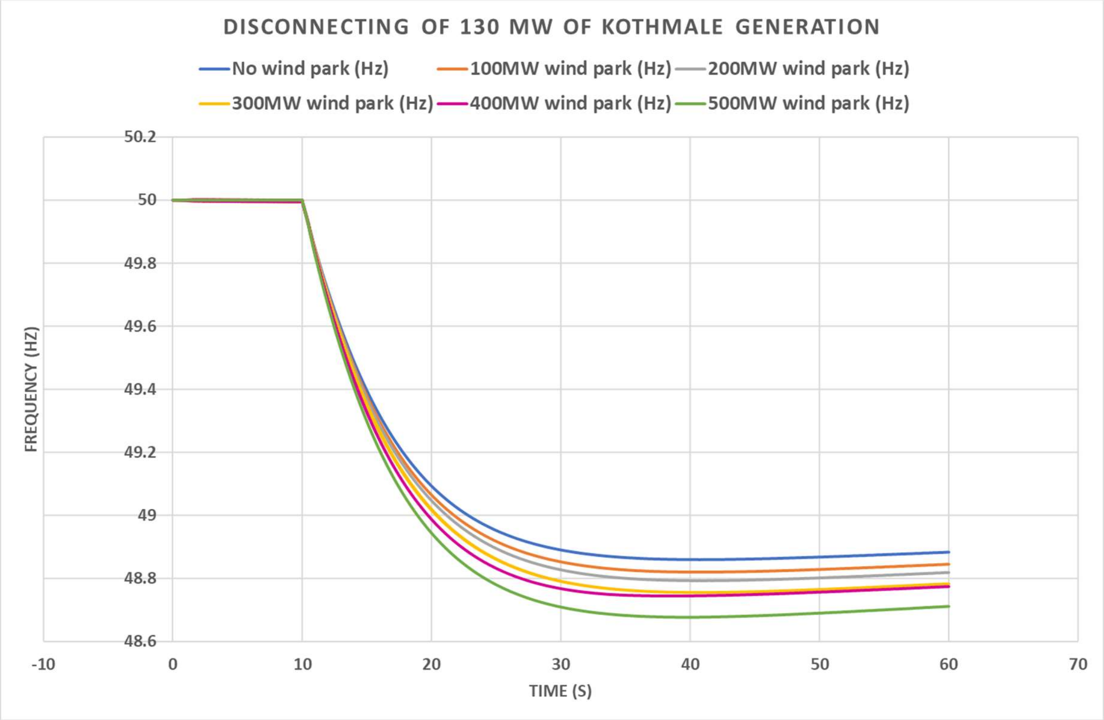


Figure 4-2: Frequency responses for disconnection of 130 MW of generation at Kotmale

It can be observed from figure 4-2 that the frequency nadir increases with the increase in wind penetration. The analytical results are shown in table 4-3. The frequency nadir increased by 16% in the 500 MW wind case compared to the no-wind case.

Table 4-3: Results of 130 MW generation disconnection

Simulation case	**Minimum frequency**	**% frequency drop w.r.t No wind case**
CASE 1:No wind	48.86	
CASE 2:100MW wind	48.82	3%
CASE 3:200MW wind	48.79	6%
CASE 4:300MW wind	48.76	9%
CASE 5:400MW wind	48.74	10%
CASE 6:500MW wind	48.68	16%

4.5 Frequency response for 300 MW generation disconnection during low demand period

There can be periods where the system demand is lower than the usual. Examples are Sundays, poya days, special days such as a new year day and etc. During such periods, the percentage wind penetration will be higher than the usual. It would be important to understand the behavior of the power system during generation disconnections. Cases for simulations are shown in table 4-4.

Table 4-4: Cases for simulations with different wind penetration; low demand case

Cases for simulations	**Hydro (MW)**	**Thermal (MW)**	**Wind park (MW)**	**Total generation (MW)**
CASE 1 - No wind	800	1200	0	2000
CASE 2 - 100MW wind	800	1100	100	2000
CASE 3 - 200MW wind	800	1000	200	2000
CASE 4 - 300MW wind	800	900	300	2000
CASE 5 - 400MW wind	800	800	400	2000
CASE 6 - 500MW wind	800	700	500	2000

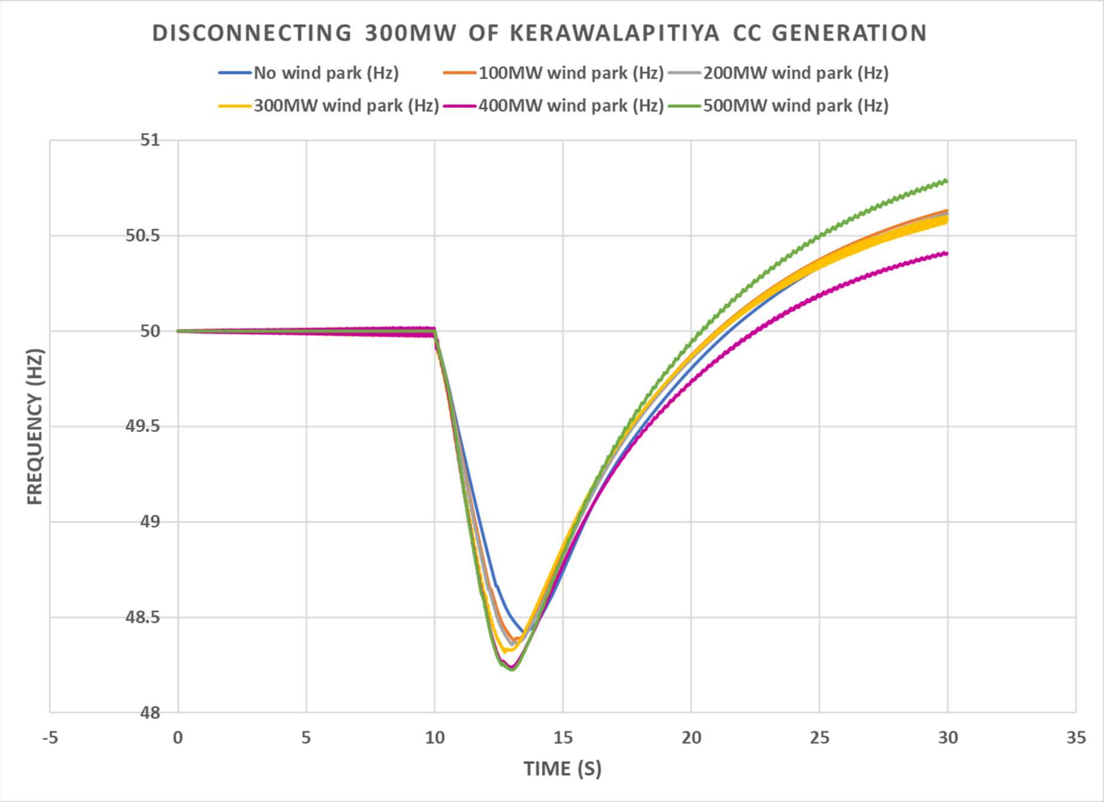


Figure 4-3: Frequency responses for disconnection of 300 MW CC at Kerawalapitiya; low demand case

As seen in the figure 4-3, the power system will be quite vulnerable during generation disconnections in low demand period. The major difference in frequency responses during the low demand period is that the frequency dip is significantly higher in the 500 MW wind case compared to the no wind case. The higher ROCOF due to poor inertia during the disturbance may have contributed to such an increase in the frequency dip with the increase in wind penetration.

5 IMPACT OF BATTERY ENERGY STORAGE SYSTEMS ON FREQUENCY RESPONSE

The purpose of this chapter is to analyze the possibility of Battery Energy Storage Systems (BESS) to improve the frequency response during generator disconnections.

5.1 Battery Energy Storage Systems (BESS)

Studies on grid scale battery energy storage systems have been continuing globally. As a result, technologies are evolving rapidly, improving the efficiency and the cost effectiveness. The trend began with the rapid increase in solar PV and wind integration to power systems which are highly intermittent sources of energy. The means of storing energy was becoming increasingly important to mitigate negative effects. Lower ramping times in millisecond range that the BESS can provide was also a reason for their consideration. Due to this fast-reacting capability which is not possible in conventional generators, it is capable of performing precise frequency regulation in power systems, which will be presented in this chapter.

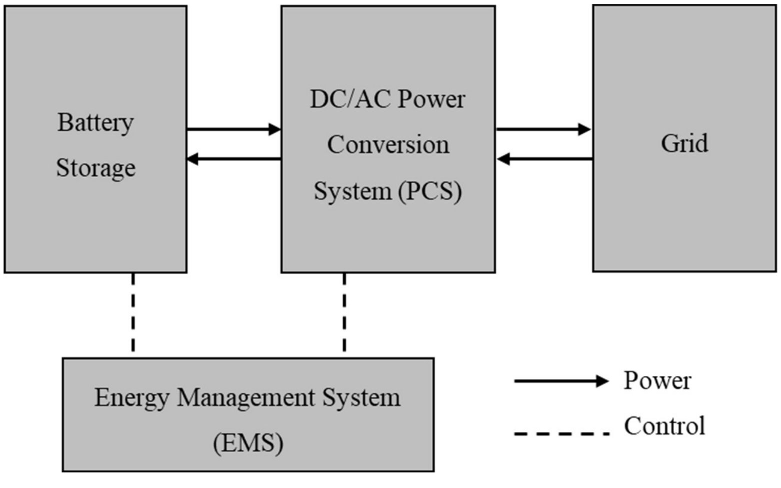


Figure 5-1: Block diagram of BESS

A basic block diagram of a BESS is shown in the figure 5-1. Battery storage is where energy is stored. The function of the power conversion system (PCS) is to convert dc to ac and ac to dc back and forth to transfer power to the grid to supply loads and transfer power from the grid to charge the battery storage. An energy management system (EMS) is responsible for controlling how the battery system should function and for monitoring the condition of the battery storage system.[5]

5.2 Overview of BESS technologies

There are several BESS technologies available. Some are already proven technologies while some of them are commercializing or in the research stage. Each technology has their advantages and disadvantages.

Global BESS projects over 1 MW by the type of technology is shown in table 5-1.

Table 5-1: Global BESS projects over 1 MW by the type of technology [5]

Global battery energy storage projects over 1MW by the technology type	
Technology type	**%**
Lithium-ion based	78.3
Sodium-Sulfur	8.9
Lead-Acid	8.3
Vanadium-Flow	3.2
Other	1.3

Lithium-ion based battery storage technology is the most commonly used technology up to now. It has more desirable properties compared with most of other technologies which makes it more suitable for grid-scale battery storage projects. The advantages of this technology are the higher efficiency, the higher capacity and also it is a commercialized technology. Despite its comparatively high cost, scarcity of material and safety risks in high temperatures, it is widely used for grid-scale battery energy storage system projects. [5]

Sodium-Sulfur battery storage technology is emerging as it provides a nearly close performance to lithium-ion batteries but at lower cost. Sodium and Sulfur are abundant and cheap. The batteries have a higher energy density and a higher efficiency. Disadvantage of this technology is that it requires 300-350 °C operating temperature to keep the electrodes in liquid form which is not the case of other battery technologies as they use solid electrodes. In turn, it has safety risks due to high operating temperature. High operating temperature also increases the corrosion of the compound materials. [5]

Lead acid batteries are the most mature technology. It is reliable and has a long life time. The cost of batteries is lower but it has demerits such as the lower efficiency and the use of environmentally hazardous materials. [5]

5.3 Modelling of BESS in PSS/E

5.3.1 Steady state modelling of BESS

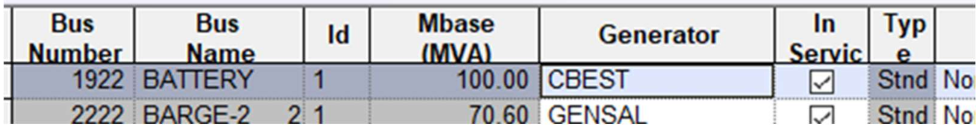
A battery energy storage system of 100MW was located at the Kolonnawa grid substation and modeled as a generator unit in PSS/E. A FACTS device was modelled at Kolonnnawa grid substation to incorporate frequency dependent signal to BESS since PSS/E BESS model itself do not have a direct method to get the system frequency. Accordingly, a FACTS device was included at the Kolonnawa grid substation, and it remained switched off during dynamic simulations.

5.3.2 Dynamic modelling of BESS

The CBEST battery storage model in PSS/E model library incorporates technology developed for United States Electric Power Industry under the sponsorship of the Electric Power Research Institute (EPRI). [6]

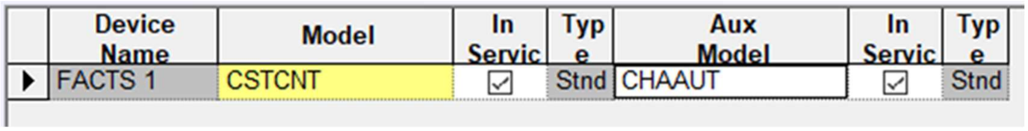
The active power input to the CBEST model is PAUX and the active power output of the model is POUT. PAUX should follow system frequency variations in order to assist the frequency response during generator disconnections. Since the CBEST model itself does not have a method to follow the frequency variation in PSS/E, an alternative method was used to obtain the frequency dependent power input to simulations.

The CHAAUT frequency dependent auxiliary signal model which can be incorporated with FACTS devices can follow the system frequency. The output of the CHAAUT model which is a power auxiliary signal should be set as the PAUX input of the CBEST model. To map the auxiliary power output of the CHAAUT model to the PAUX input of the CBEST model, a user-written FORTRAN code was used (see figure 5-4). The FORTRAN code was compiled to create a dynamic link library (DLL) file for the dynamic simulation. The CSTCNT PSS/E dynamic model was used for the FACTS device. [6][10] Dynamic modelling of BESS in PSS/E is shown in figure 5-2 and 5-3.



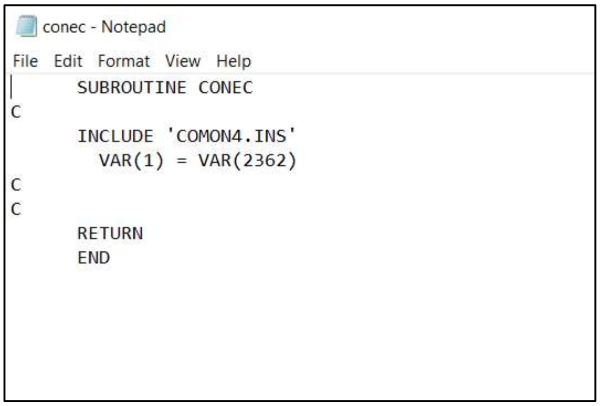
Bus Number	Bus Name	Id	Mbase (MVA)	Generator	In Servic	Type	
1922	BATTERY	1	100.00	CBEST	☑	Stnd	No
2222	BARGE-2 2	1	70.60	GENSAL	☑	Stnd	No

Figure 5-2: Dynamic modelling of the BESS using CBEST



Device Name	Model	In Servic	Type	Aux Model	In Servic	Type
FACTS 1	CSTCNT	☑	Stnd	CHAAUT	☑	Stnd

Figure 5-3: Dynamic modelling of the FACTS device



```
      SUBROUTINE CONEC
C
      INCLUDE 'COMON4.INS'
        VAR(1) = VAR(2362)
C
C

      RETURN
      END
```

Figure 5-4: FORTRAN CODE to map CHAAUT signal output to CBEST model input

The normally allowed operating frequency range in the power system of Sri Lanka is 49.5-50.5 Hz (±0.5 Hz). Unlike in large power systems, the steady state frequency variations in the power system of Sri Lanka are higher. Considering regular frequency variations and the operating range of the frequency, the dead band to activate BESS during frequency events was set at ±0.4 Hz for the dynamic simulation. This will avoid frequent triggering of the BESS unnecessarily. Positive and negative slopes were selected as 25 MW/0.1Hz and -25 MW/0.1Hz respectively to keep the performance of BESS in line with actual BESS ramp times which will be explained in the section 5.6. Transducer time constant was set to 1s [10]. The installed capacity of the BESS was

100 MW. The energy capacity is not relevant for the dynamic simulation and it was not specified for the dynamic simulation.

5.4 Simulation plan

The ultimate target of simulations was to analyze how the power system behaves during generator disconnections, with and without a BESS installed. To achieve that, simulations should be carried out under similar power system conditions with and without a BESS and the frequency responses were observed.

A BESS was modelled in the validated PSS/E model of the present power system described in sections 3.1 and 3.2. The total system generation was set to 2000 MW. Plant-wise generation was set considering a hydro dominant case for all simulations for the consistency of the results. The plant-wise generation used for simulations is shown in APPENDIX E.

Dynamic simulations were carried out for two scenarios.

1. 150 MW of generation disconnection with a BESS and without a BESS
2. 75 MW of generation disconnection with a BESS and without a BESS

Above scenarios were selected in order to observe the BESS response to different magnitudes of generation disconnections.

5.5 Simulation results

Results of simulations are shown in sections 5.5.1 and 5.5.2.

5.5.1 Disconnection of 150 MW of generation

Frequency responses for disconnection of 150 MW are shown in figure 5-5. The active power support from the BESS during the event is shown in figure 5-6. The active power support from the frequency controlling generator is shown in figure 5-7.

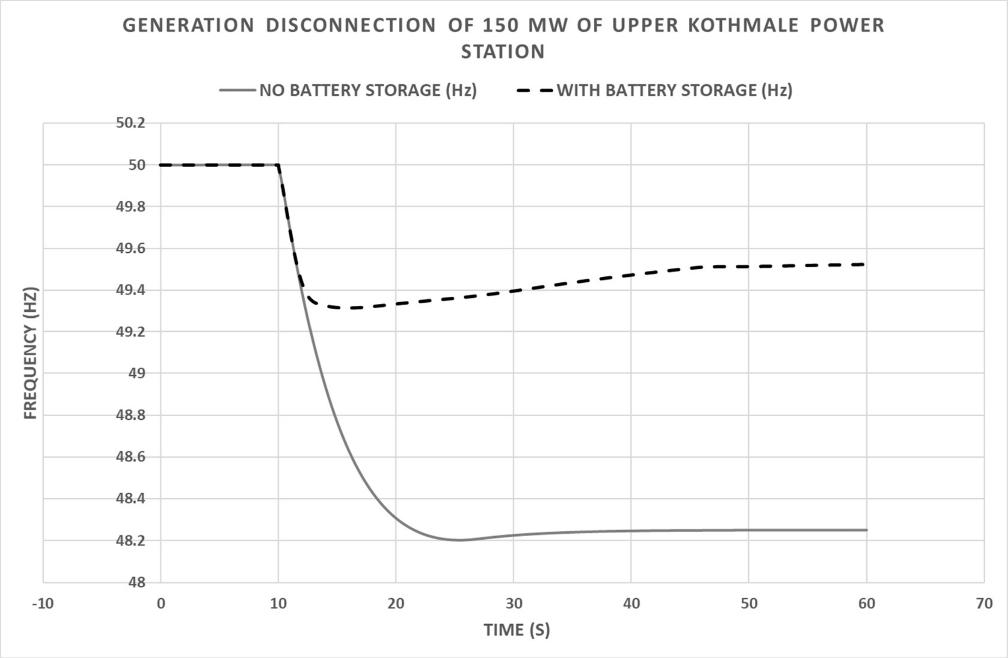


Figure 5-5: Frequency responses after 150 MW of generation disconnection

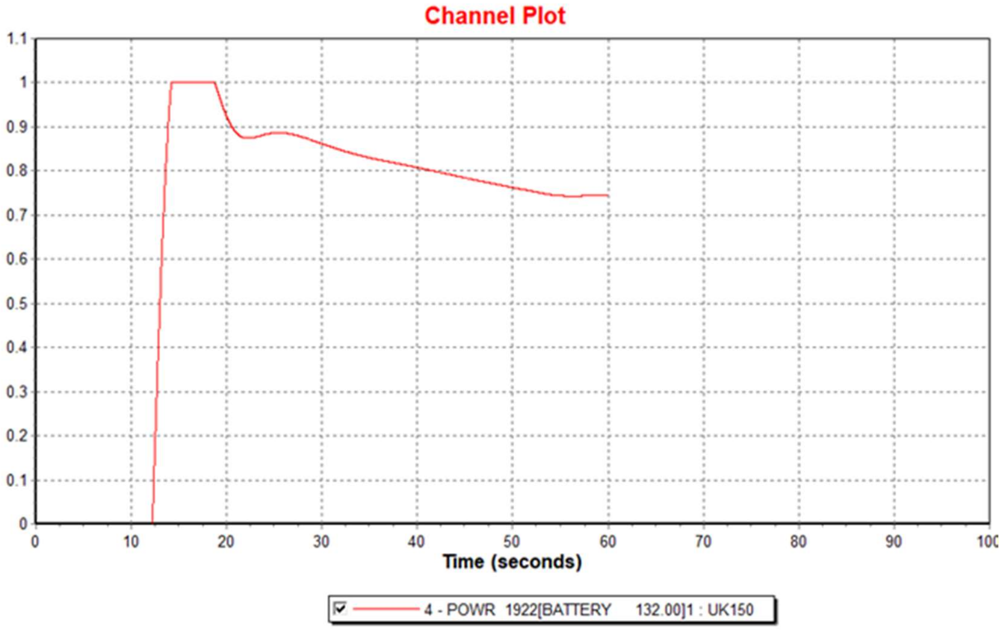


Figure 5-6: Active power support (per unit) from BESS for 150 MW of generation disconnection

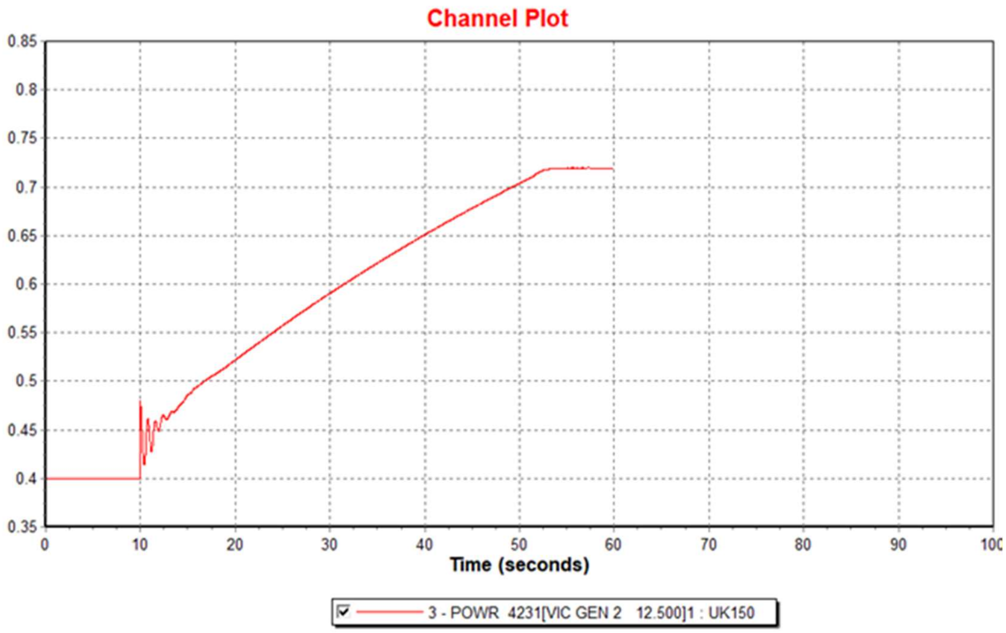


Figure 5-7: Active power support (per unit) from frequency controlling generator (Victoria generator 02) for 150 MW of generation disconnection

As shown in the figure 5-5, the minimum frequency reached improved to 49.32 Hz with a BESS compared with 48.2 Hz without a BESS. Introduction of a BESS has avoided the operation of the UFLS during the event. As shown in the figure 5-6, the BESS reached its maximum power delivery within 2s from the activation according to the logic of operation programmed for the simulation. Unlike in larger power systems, for the power system of Sri Lanka, the frequency response has improved significantly for 150 MW of generation disconnection with a BESS.

Accordingly, if we assume the system frequency bias is 10MW/0.1Hz, only around 68 MW from the spinning reserve is required to get the frequency back to 50 Hz until generators started and put the BESS back to nominal. So, the spinning reserve requirement has also been reduced with the introduction of a BESS.

5.5.2 Disconnection of 75 MW of generation

Frequency responses for disconnection of 75 MW are shown in the figure 5-8. The active power support from the BESS during the event is shown in the figure 5-9. The active power support from the frequency controlling generator is shown in the figure 5-10.

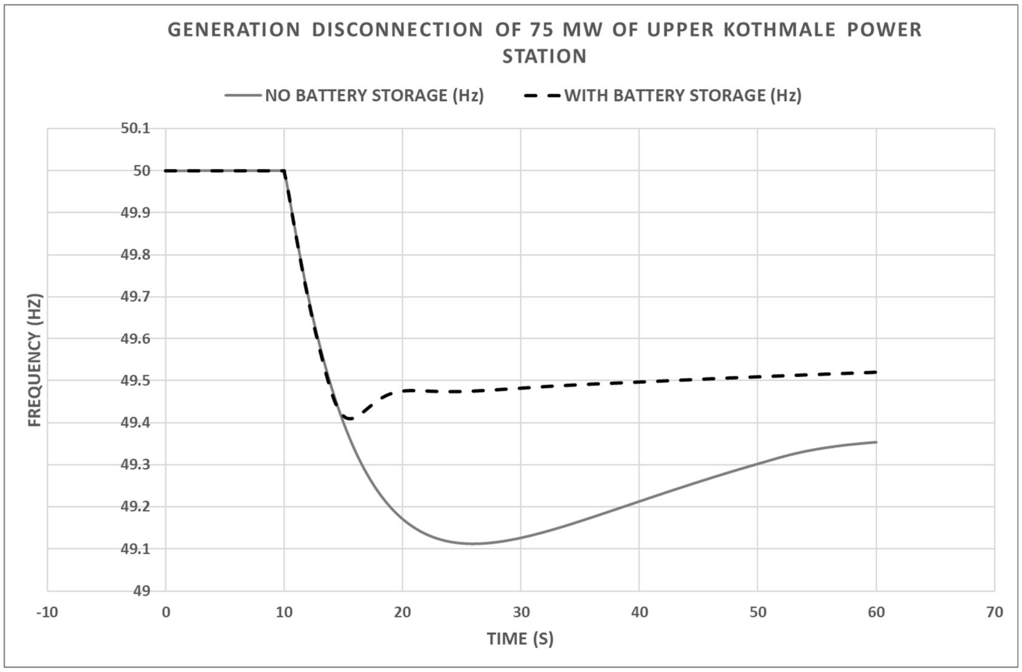


Figure 5-8: Frequency responses after 75 MW of generation disconnection

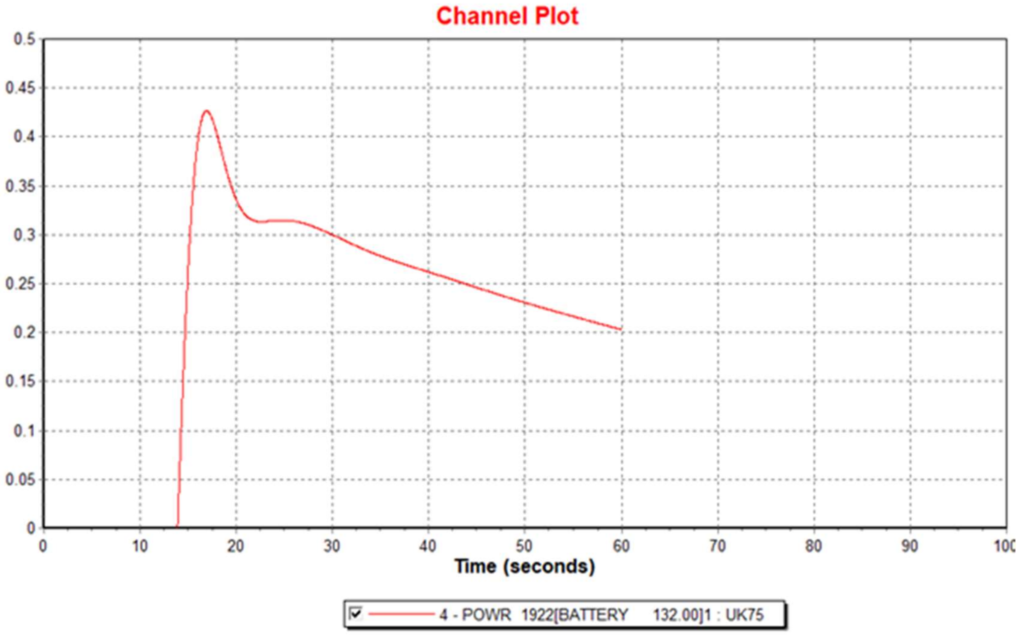


Figure 5-9: Active power support (per unit) from BESS for 75 MW of generation disconnection

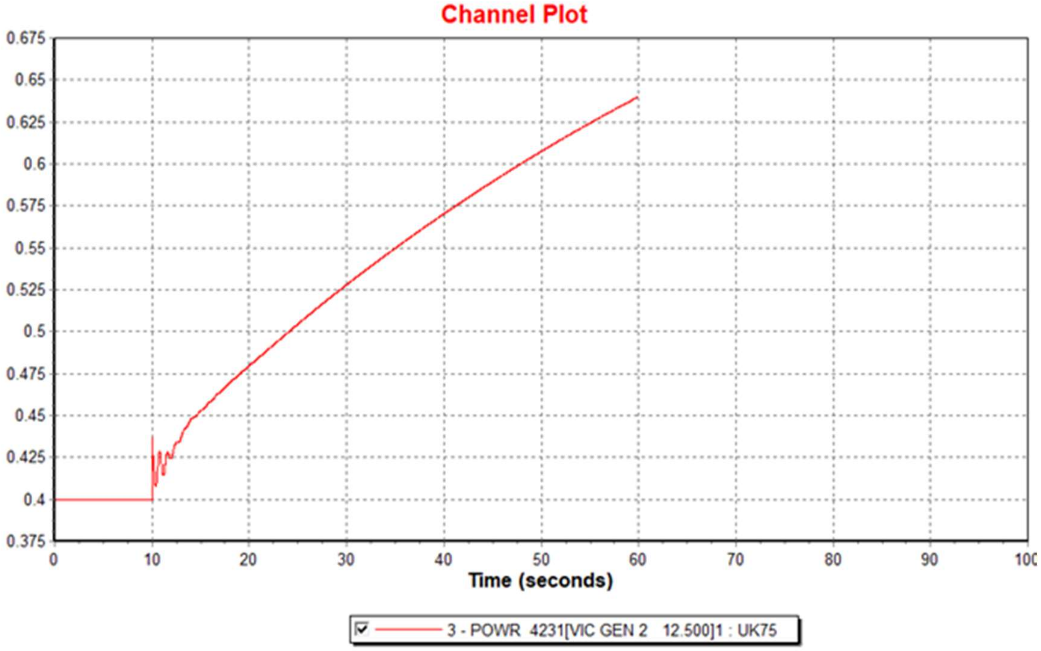


Figure 5-10: Active power support (per unit) from frequency controlling generator (Victoria generator 02) for 75 MW of generation disconnection

As shown in the figure 5-8, the minimum frequency reached improved to 49.41 Hz with a BESS compared to 49.11 Hz without a BESS. As shown in the figure 5-9, the BESS reached its maximum power delivery within 3s from the activation according to the logic of operation programmed for the simulation. Unlike in larger power systems, for the power system Sri Lanka, the frequency response has improved significantly for 75 MW of generation disconnection with a BESS.

Accordingly, if we assume the system frequency bias is 10MW/0.1Hz, only around 59 MW from the spinning reserve is required to get the frequency back to 50 Hz until generators started and put the BESS back to nominal. So, the spinning reserve requirement has also been reduced with the introduction of a BESS.

5.6 Justification of simulation results

The BESS installed at Kilroot power station, Northern Ireland has a delay time around 100ms and a ramp time around 300ms. However, these parameters have not been optimized for a strict ramping and they assure that the ramp time can be compacted to less than 100ms. At present, the BESS is used as a fast frequency reserve. The delay time is the time to identify the loss of generation. The ramp time is the time taken to reach the maximum power output from zero power output. [7]

In simulations in the section 5.6, ramp times are well within capable ramp times of BESSs. This clearly shows that the frequency response can be further improved by a proper selection and tuning of the control logic.

CHAPTER 6

6 ANALYSIS OF COSTS OF BATTERY ENERGY STORAGE SYSTEMS

6.1 The main initial capital cost components of BESS

A battery energy storage system comprises of several main components. The total BESS cost can be estimated as a summation of the cost of each component. The main cost components are described in sections 6.1.1, 6.1.2, 6.1.3 and 6.1.4

6.1.1 The cost of the battery pack

The cost of the battery pack includes the costs of electrodes, electrolytes, separators, packaging and all the other parts of the battery storage. The cost varies depending on the technology used. Li-ion batteries were considered for the research as it is the battery that is widely used in large scale BESSs and It is the technology that is well proven and commercialized. Usually, the cost of the battery pack is represented in \$/kWh or in a similar unit. [8]

6.1.2 The cost of power conversion system (PCS)

The cost of power conversion system includes costs of inverters, inverter controls, packaging and costs of other parts of the power conversion system. Since this cost depends on the power rating of the conversion, the cost of the power conversion system is represented in \$/kW or in a similar unit. The cost of a standalone inverter is lesser compared to inverters that can co-locate solar PV. For this study, the power conversion system considered is for a stand-alone BESS. [8]

6.1.3 The cost of the balance of plant (BOP)

The cost of the balance of plant includes costs of transformers, auxiliary systems, wiring, SCADA systems and controls…etc. The cost is usually represented in \$/kW or in a similar unit. [8]

6.1.4 The cost of construction and commissioning (C&C)

This is also referred as EPC cost (Engineering, Procurement and Construction). This includes costs of designing, procurement, transport, labor, grid integration, taxes, administrative expenses, etc. [8]

6.2 Levelized cost of storage for BESS (LCOS)

Levelized cost of storage represents the cost of an electricity unit delivered from the BESS to the grid. It is comparable to the unit generation cost of a power station. The unit of LCOS is $/kWh or a similar unit. It is calculated from discounted costs divided by the discounted total energy delivered for the project life.

$$\mathrm{LCOS}=\frac{\sum_{t=1}^{t=T}\text{Discounted Capital Costs}_t+\sum_{t=1}^{t=T}\text{Discounted O\&M Costs}_t+\sum_{t=1}^{t=T}\text{Discounted Charging Cost}_t}{\sum_{t=1}^{t=T}\text{Discounted energy supplied}_t}$$

t=year, T=Project life

6.3 Capital cost projections for standalone BESSs

In recent years, the prices of Li-ion batteries have declined sharply. The price of Li-ion batteries is expected to reduce further in the future. National Renewable Energy Laboratory, Colorado, USA have been developing cost projections of BESS capital costs based on reputed, well known publications on battery energy storage. In their recent update for 2020 of the battery storage capital costs, they have considered 19 publications which is shown in APPENDIX F to make their cost predictions. They have made their cost projections for 4-hour Li-ion battery energy storage systems. [9]

They have come up with three sets of cost projections for the future; low, mid and high which is depicted in the figure 6-1. They have considered publications dated 2018 and later for cost projections.[9]

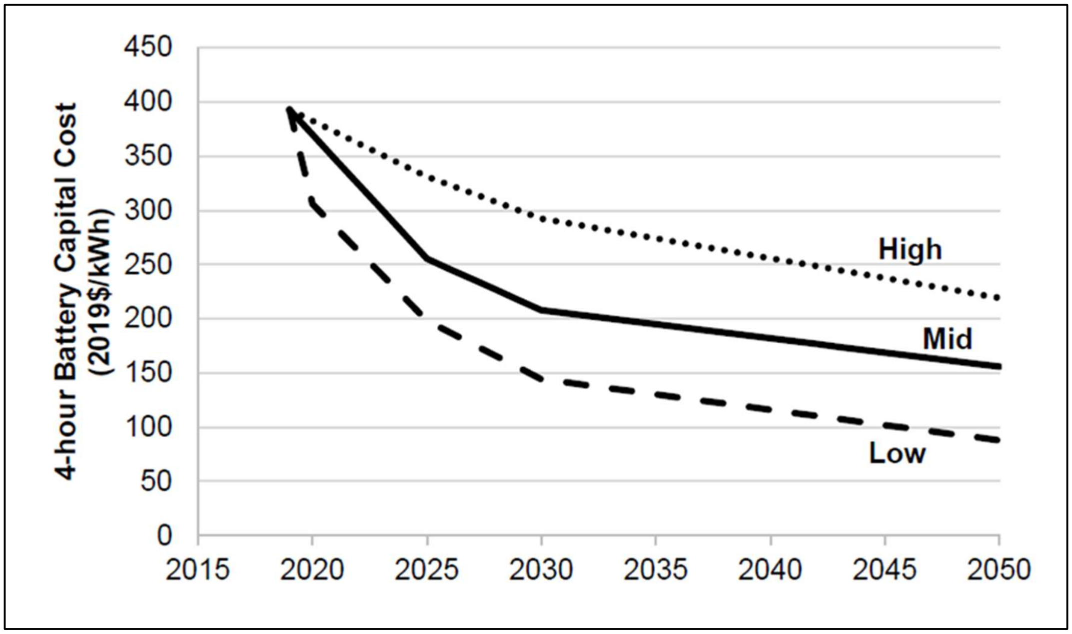


Figure 6-1: Battery capital cost projections for 4-hour system by National Renewable Energy Laboratory, Colorado; 2020 update [9]

Samples of cost projections from the figure 6-1 were selected for the study. The selected samples are shown in the table 6-1.

Table 6-1: The sample cost projections for 4-hour system for the cost analysis for BESS

BESS capital cost estimation ($/kWh)	**Low**	**Mid**	**High**
2025	205	273	331
2030	144	208	293
2050	88	156	219
2019	393	393	393

6.4 Calculation example: Calculation of LCOS for 2025 low-cost projection

Battery energy storage system specifications, parameters used for calculations are shown in the table 6-2.

Table 6-2: Battery energy storage system specifications, parameters for calculations

Parameters	
Power Rating (MW)	100
Energy Capacity (MWh)	400
Depth of Discharge Cycles/Day	1
Operating days/year	350
Project life(years)	20
Unit cost of energy source used for charging (Rs/kWh)	19
Efficiency %	85%

$$\text{Initial capital cost(\$)}=\text{Cost projection}_{\text{year t}}(\$/\text{kWh})\times\text{Energy capacity(kWh)}$$

$$\text{Initial capital cost(\$)}=205(\$/\text{kWh})\ \times400{,}000\text{kWh}=\$82{,}000{,}000$$

The Augmentation cost represents the expense to maintain full usable energy storage capacity over the project life. The augmentation cost can be approximated to 2.5% of the Battery storage cost. Battery storage cost is approximately 55% of the initial capital cost for 4-hour BESS system [12] (45% and 35% of the initial capital cost for 2-hour and 1-hour BESS systems respectively).

Accordingly,

Augmentation cost(\$)=2.5%×55%×\$ 82,000,000=\$1,127,500 per year

$$\text{Total capital cost}_{\text{year t}}=\text{Capital cost}_{\text{year t}}+\text{Augmentation cost}_{\text{year t}}$$

$$\text{Charging cost(\$)}=\frac{\text{unit cost of energy source of charging(\$/kWh)}}{\text{Efficiency}}\times\text{Total generation}_{\text{year t}}\text{(kWh)}$$

The total generation per year assumed at 140,000 MWh with assumptions of 1 discharge cycle per day and operation of 350 days per year.

$$\text{Charging cost(\$)}=\frac{19\ \text{Rs/kWh}\times1/180(\ \$/\text{Rs}\ )}{0.85}\times140{,}000\times1000\ \text{kWh}=\$\ 17{,}385{,}620.92$$

The US dollar conversion rate was assumed at 180 Rs/\$.

The O&M cost for a year was assumed to be 1% of the initial capital cost

$$\text{O\&M cost}_{\text{year t}}(\$)=1\%\times 82{,}000{,}000=\$\ 820{,}000$$

Once all above components were calculated, the levelized cost of storage can be calculated.

$$\text{LCOS}=\frac{\sum_{t=1}^{t=T}\text{Discounted Capital Costs}_t+\ \sum_{t=1}^{t=T}\text{Discounted O\&M Costs}_t+\sum_{t=1}^{t=T}\text{Discounted Charging Cost}_t}{\sum_{t=1}^{t=T}\text{Discounted energy supplied}_t}$$

$$\text{t=year, T=Project life}$$

An economic discount rate of 10% in real terms was assumed as it is the rate used in cost analysis for public projects in Sri Lanka.

The calculation is shown in table 6-3.

Table 6-3: Levelized Cost of Storage estimation for 4-hour system for 2025 low-cost projection

YEAR	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Total generation(MWh) [T]		140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000
Capital cost ($) [A]	82,000,000	0	0	0	0	0	0	0	0	0	0
Augmentation cost ($) [B]		1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500
Total capital cost ($) [C] = [A]+[B]	82,000,000	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500
Charging cost ($) [D]		17,385,621	17,385,621	17,385,621	17,385,621	17,385,621	17,385,621	17,385,621	17,385,621	17,385,621	17,385,621
O&M cost ($) (1% of CAPEX) [E]		820,000	820,000	820,000	820,000	820,000	820,000	820,000	820,000	820,000	820,000
Operating cost($) [F]=[D]+[E]		18,205,621	18,205,621	18,205,621	18,205,621	18,205,621	18,205,621	18,205,621	18,205,621	18,205,621	18,205,621
Discounted total capital cost ($) [C]*	**82,000,000**	**1,127,500**	**1,025,000**	**931,818**	**847,107**	**770,098**	**700,089**	**636,444**	**578,586**	**525,987**	**478,170**
Discounted operating cost ($) [F]*		**18,205,621**	**16,550,564**	**15,045,968**	**13,678,152**	**12,434,684**	**11,304,258**	**10,276,598**	**9,342,362**	**8,493,057**	**7,720,960**
Discounted total generation ($) [T]*		**140,000**	**127,273**	**115,702**	**105,184**	**95,622**	**86,929**	**79,026**	**71,842**	**65,311**	**59,374**

YEAR	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**Total**
Total generation(MWh) [T]	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	
Initial capital cost ($) [A]	0	0	0	0	0	0	0	0	0	0	
Augmentation cost ($) [B]	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	
Total capital cost ($) [C] = [A]+[B]	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	1,127,500	
Charging cost ($) [D]	17,385,621	17,385,621	17,385,621	17,385,621	17,385,621	17,385,621	17,385,621	17,385,621	17,385,621	17,385,621	
O&M cost ($) (1% of CAPEX) [E]	820,000	820,000	820,000	820,000	820,000	820,000	820,000	820,000	820,000	820,000	
Operating cost($) [F]=[D]+[E]	18,205,621	18,205,621	18,205,621	18,205,621	18,205,621	18,205,621	18,205,621	18,205,621	18,205,621	18,205,621	
Discounted total capital cost ($) [C]*	**434,700**	**395,182**	**359,256**	**326,597**	**296,906**	**269,915**	**245,377**	**223,070**	**202,791**	**184,355**	**92,558,947**
Discounted operating cost ($) [F]*	**7,019,055**	**6,380,959**	**5,800,872**	**5,273,520**	**4,794,109**	**4,358,281**	**3,962,074**	**3,601,885**	**3,274,441**	**2,976,764**	**170,494,185**
Discounted total generation ($) [T]*	**53,976**	**49,069**	**44,608**	**40,553**	**36,866**	**33,515**	**30,468**	**27,698**	**25,180**	**22,891**	**1,311,089**

$$\text{Levelized Cost of Storage} = \frac{\sum[\mathrm{C}]^{*} + \sum[\mathrm{F}]^{*}}{\sum[\mathrm{T}]^{*}} = \frac{92{,}558{,}947 + 170{,}494{,}185}{1{,}311{,}089} = 200\ \$/\mathrm{MWh} = 36\ \mathrm{Rs/kWh}$$

6.5 Levelized Cost of Storage (LCOS) results summary for a 4-hour BESS

Using the same method as described in the section 6.4, the LCOS was calculated for capital cost projections in the table 6-1. Results are shown in table 6-3.

Table 6-4: Levelized Cost of Storage (LCOS) results summary for 4-hour system

	Levelized cost of storage estimations for BESS (Rs/kWh)		
Year	**Low**	**Mid**	**High**
2025	36	41	45
2030	32	36	42
2050	28	33	37

According to the table 6-4, The approximate cost of a unit delivered from BESS would be around 36-45 Rs/kWh in 2025. In 2030, it is estimated that the cost per unit would be around 32-42 Rs/kWh. In 2050, the estimation would be around 28-37 Rs/kWh.

Since the charging cost assumed is 19 Rs/kWh, the cost for storing only would be around 17-26 Rs/kWh in 2025, 13-23 Rs/kWh in 2030 and 9-18 Rs/kWh in 2050.

In the cost analysis in section the 6.4, it was assumed that the BESS will operate for 4 hours a day. In addition to the supportive role in frequency regulation, the BESS should be utilized for purposes such as peak support, NCRE intermittency control, load shifting and etc to meet the requirement.

6.6 Levelized Cost of Storage (LCOS) for a 2-hour BESS

BESS capital cost projections for 2,4 and 6-hour systems using mid cost projection is shown in the figure 6-2.

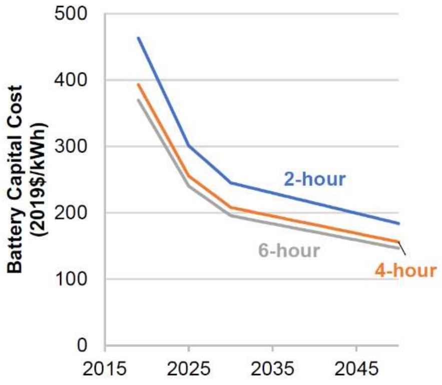


Figure 6-2: Cost projections for 2-, 4-, and 6-hour duration batteries using the mid cost projection [9]

Capital cost projections in the table 6-5 were assumed based on the figure 6-2 to calculate the levelized cost of storage.

Table 6-5: Sample cost projections for a 2-hour system for the cost analysis for BESS

BESS capital cost estimation ($/kWh) 2-hour system	**Low**	**Mid**	**High**
2025	225	300	364
2030	173	250	352
2050	102	180	253

Calculation of levelized cost of storage for the 2025 low-cost projection for a 2-hour system is shown in the table 6-7. Levelized cost of storage results based on sample cost projections in the table 6-5 are shown in the table 6-6.

Table 6-6: Levelized Cost of Storage (LCOS) results summary for a 2-hour system

	Levelized cost of storage estimations for BESS (Rs/kWh)		
Year	**Low**	**Mid**	**High**
2025	37	42	46
2030	34	39	46
2050	29	34	39

Table 6-7: Levelized Cost of Storage estimation for 2-hour system for 2025 low-cost projection

YEAR	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Total generation(MWh) [T]		70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000
Capital cost ($) [A]	45,054,945	0	0	0	0	0	0	0	0	0	0
Augmentation cost ($) [B]		506,868	506,868	506,868	506,868	506,868	506,868	506,868	506,868	506,868	506,868
Total capital cost ($) [C] = [A]+[B]	45,054,945	506,868	506,868	506,868	506,868	506,868	506,868	506,868	506,868	506,868	506,868
Charging cost ($) [D]		8,692,810	8,692,810	8,692,810	8,692,810	8,692,810	8,692,810	8,692,810	8,692,810	8,692,810	8,692,810
O&M cost ($) (1% of CAPEX) [E]		450,549	450,549	450,549	450,549	450,549	450,549	450,549	450,549	450,549	450,549
Operating cost($) [F]=[D]+[E]		9,143,360	9,143,360	9,143,360	9,143,360	9,143,360	9,143,360	9,143,360	9,143,360	9,143,360	9,143,360
Discounted total capital cost ($) [C]*	**45,054,945**	**506,868**	**460,789**	**418,899**	**380,818**	**346,198**	**314,725**	**286,114**	**260,103**	**236,458**	**214,962**
Discounted operating cost ($) [F]*		**9,143,360**	**8,312,145**	**7,556,496**	**6,869,542**	**6,245,038**	**5,677,307**	**5,161,188**	**4,691,989**	**4,265,445**	**3,877,677**
Discounted total generation ($) [T]*		**70,000**	**63,636**	**57,851**	**52,592**	**47,811**	**43,464**	**39,513**	**35,921**	**32,656**	**29,687**

YEAR	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**Total**
Total generation(MWh) [T]	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	
Capital cost ($) [A]	0	0	0	0	0	0	0	0	0	0	
Augmentation cost ($) [B]	506,868	506,868	506,868	506,868	506,868	506,868	506,868	506,868	506,868	506,868	
Total capital cost ($) [C] = [A]+[B]	506,868	506,868	506,868	506,868	506,868	506,868	506,868	506,868	506,868	506,868	
Charging cost ($) [D]	8,692,810	8,692,810	8,692,810	8,692,810	8,692,810	8,692,810	8,692,810	8,692,810	8,692,810	8,692,810	
O&M cost ($) (1% of CAPEX) [E]	450,549	450,549	450,549	450,549	450,549	450,549	450,549	450,549	450,549	450,549	
Operating cost($) [F]=[D]+[E]	9,143,360	9,143,360	9,143,360	9,143,360	9,143,360	9,143,360	9,143,360	9,143,360	9,143,360	9,143,360	
Discounted total capital cost ($) [C]*	**195,420**	**177,654**	**161,504**	**146,822**	**133,474**	**121,340**	**110,309**	**100,281**	**91,165**	**82,877**	**49,801,725**
Discounted operating cost ($) [F]*	**3,525,161**	**3,204,692**	**2,913,356**	**2,648,506**	**2,407,732**	**2,188,848**	**1,989,862**	**1,808,965**	**1,644,514**	**1,495,012**	**85,626,835**
Discounted total generation ($) [T]*	**26,988**	**24,535**	**22,304**	**20,277**	**18,433**	**16,757**	**15,234**	**13,849**	**12,590**	**11,446**	**655,544**

$$\text{Levelized Cost of Storage}=\frac{\sum[\mathrm{C}]^{*}+\sum[\mathrm{F}]^{*}}{\sum[\mathrm{T}]^{*}}=\frac{92{,}558{,}947+170{,}494{,}185}{1{,}311{,}089}=207\ \$/\mathrm{MWh}=37\ \mathrm{Rs/kWh}$$

6.7 Levelized Cost of Storage (LCOS) for 1-hour BESS

Levelized cost of storage for 1-hour BESS can be calculated in the similar way and results are shown in the table 6-8.

Table 6-8: Levelized Cost of Storage (LCOS) results summary for a 1-hour system

	Levelized cost of storage estimations for BESS (Rs/kWh)		
Year	**Low**	**Mid**	**High**
2025	36	41	45
2030	32	36	42
2050	28	33	37

6.8 Use of a BESS only for the frequency corrective purpose

Details of UFLS events in 2019 are shown in the table 6-9

Table 6-9: UFLS events in 2019 [18]

UFLS Stage	**no of occurrences**	**Energy loss (MWh)**
I	18	280.3
II	9	169.3
III	4	73.6
IV	1	2.3
V	0	0
df/dt	0	0
Total energy loss (MWh)		**525.5**

As shown in the table 6-9, the total energy loss due to UFLS in 2019 was 525.5 MWh. The cost of energy not served (ENS) is approximately 134 Rs/kWh according to the long-term generation expansion plan of Ceylon Electricity Board. The cost of unserved energy due to UFLS in 2019 can be assumed by multiplying the cost of ENS (134 Rs/kWh) and the total energy loss (525.5 MWh) in the table 6-9 and it is Rs. 70.4 million. As seen in the table 6-7, the present value of BESS capital costs is $ 49.8 million. The annual cost for BESS can be estimated by dividing the present value by the annuity factor at a discount rate of 10% for a project life of 20 years (8.51) which is $ 5.9 million. Assuming a conversion rate of 180 Rs/USD, the annual cost for a BESS can be approximated as Rs. 1,053.3 million. The annual cost for BESS is significantly higher than the annual economic cost of unserved energy in 2019. Therefore, the investment on a BESS is not economical if a BESS is to be used only for frequency support in contingencies. In this comparison, it was assumed that the energy loss due to UFLS stage I can be avoided, while the energy loss due to UFLS stage II, III and IV may also be reduced significantly by a BESS.

Frequency distribution below 49.6 Hz in 2019 is shown in the table 6-10. Samples are taken in 5 second intervals. So, it can be assumed that the duration of each occurrence is 5 seconds.

Table 6-10: Frequency distribution below 49.6 Hz in 2019 [18]

Frequency (Hz)	Occurrence	Energy required for frequency correction (MWh)
49.6	783	43.5
49.55	537	33.6
49.5	311	21.6
49.45	240	18.3
49.4	218	18.2
49.35	162	14.6
49.3	103	10.0
49.25	85	8.9
49.2	46	5.1
49.15	48	5.7
49.1	25	3.1
49.05	27	3.6
49	239	33.2
Total energy required for frequency correction (MWh)		219.3

As seen in the table 6-10, the energy required to correct the frequency was approximately 219 MWh in 2019 which can be accomplished by using the a BESS (System frequency bias was assumed at 10MW/0.1Hz).

It can be seen from the data in the table 6-9 and 6-10 that if BESS was used for the purpose of the frequency correction only, the annual energy from a BESS would be below 1 GWh. Considering high capital costs and high augmentation costs, BESS is under-utilized and it will not be economical. It is an unrealistic option.

The observations in this chapter will be discussed in the chapter 8.

CHAPTER 6

7 CASE STUDY ON COST OF SPINNING RESERVE

7.1 Introduction

The general definition of spinning reserve is the amount of active power that can be obtained from connected generators within 10 minutes. This implies that the spinning reserve depends on the number of generators connected and the ramp times of the connected generators. In case of a generator disconnection, the spinning reserve can take over the loss of generation until the power system comes to its normal.

For example, if the disconnected generation is 100 MW, approximately 100 MW from the spinning reserve will be required to bring the frequency back to the previous value if we neglect the frequency dependency of loads. If the spinning reserve of the system is 50 MW at the particular moment of the generation disconnection, additional generators will be needed to supply the load. Till then, the loads have to be disconnected or the system will operate below the nominal frequency. In order to reduce the impact of sudden generation disconnection, an adequate amount of spinning reserve should be maintained.

If we analyze power system security standards in other countries, they are maintaining a spinning reserve which will be sufficient to withstand a credible generation disconnection. Usually, it is the active power output of the largest generator unit connected to the power system in that moment. [1][2][3]

The current practice in Sri Lanka is to maintain a spinning reserve greater than 5% from the total system generation. For example, if the total system demand at a particular moment is 2000 MW, the minimum amount of spinning reserve to be maintained is 100 MW. At present, the largest generator unit size connected is 270 MW which is larger than the spinning reserve margin at 2000 MW of total generation. So, it can be seen that internationally practiced levels of spinning reserve are not maintained in the power system.

The aim of this case study is to identify and analyze the additional cost if an internationally practiced level of spinning reserve is maintained.

7.2 Defining cases for the spinning reserve cost analysis

The total daily generation for the case study was selected from a set of actual generation data in 2019. Averaged total generation of the data set was taken for the analysis.

The selected generation curve was divided in to four sections as shown in the figure 7-1 and the table 7-1.

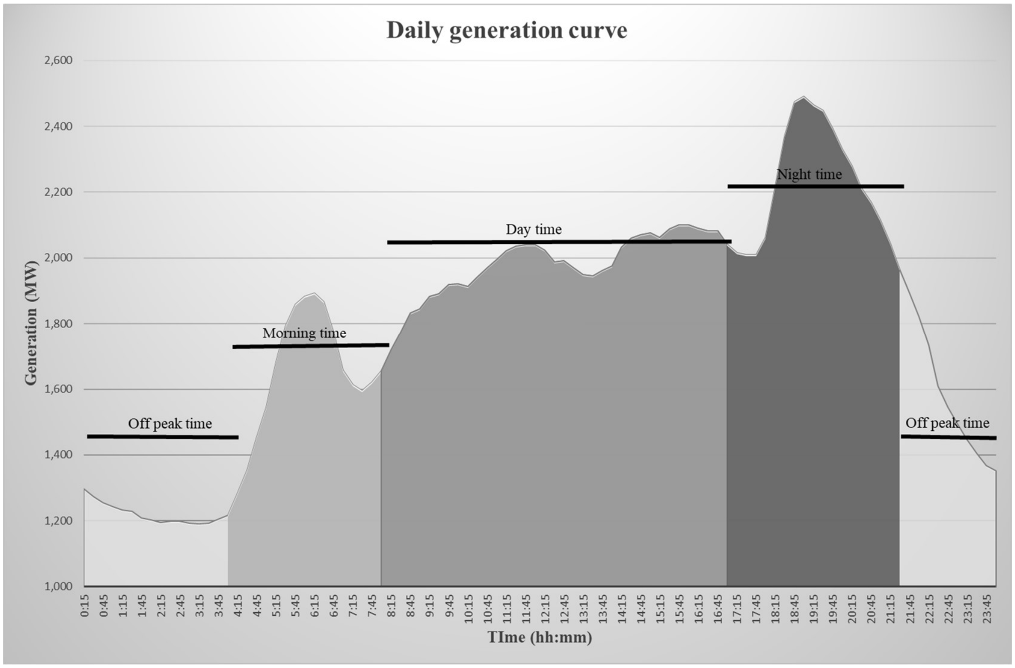


Figure 7-1: Daily generation curve for calculation of additional cost for spinning reserve

Table 7-1: Sections of the daily generation curve for the calculation of additional cost for spinning reserve

	Time	Average generation of the time period (MW)
Off peak time	21:30 - 4:00	1420
Morning time	4:00 - 8:00	1660
Day time	8:00 - 17:00	2000
Night time	17:00 - 21:30	2200

For each section, economic dispatches were prepared.

1. CASE A: Economic dispatch with spinning reserve of the size of the largest generation connected
2. CASE B: Economic dispatch with 5% spinning reserve from the total generation

Case studies were carried out separately for a hydro dominant day and for a thermal dominant day. Economic dispatches used for the study are shown in APPENDIX G. Then the spinning reserve costs were compared between CASE A and CASE B to calculate the additional cost if an international practiced level of spinning reserve was maintained.

7.3 Cost components of the additional spinning reserve

To compare the cost of spinning reserve between CASE A and CASE B, main cost components were identified.

$$\begin{array}{l}\text{Cost for}\\ \text{additional}\\ \text{spinning}\\ \text{reserve}\end{array} = \begin{array}{l}\text{Thermal cost}\\ \text{difference}\\ \text{between}\\ \text{CASE A\&B}\end{array} + \begin{array}{l}\text{Hydro cost}\\ \text{difference}\\ \text{between}\\ \text{CASE A\&B}\end{array} + \begin{array}{l}\text{Startup costs}\\ \text{difference}\\ \text{between}\\ \text{CASE A\&B}\end{array} + \begin{array}{l}\text{Cost difference}\\ \text{due to part load}\\ \text{operation of hydro}\\ \text{between CASE}\\ \text{A\&B}\end{array}$$

7.3.1 Thermal cost difference between CASE A & B

$$\begin{array}{c}\text{Thermal}\\ \text{cost difference}\end{array} = \sum_{i=1}^{i=n}\left(\begin{array}{c}\text{Additional energy}\\ \text{from i}^{\text{th}}\text{ thermal generator}\\ \text{in CASE A (MWh)}\end{array} \times \begin{array}{c}\text{Unit cost of the i}^{\text{th}}\\ \text{thermal generator}\\ \text{(Rs/MWh)}\end{array}\right)$$

n = number of thermal generators connected

7.3.2 Hydro cost difference between CASE A & B

$$\begin{array}{c}\text{Hydro}\\ \text{cost difference}\end{array} = \sum_{i=1}^{i=n}\left(\begin{array}{c}\text{Additional energy}\\ \text{from i}^{\text{th}}\text{ hydro generator}\\ \text{in CASE A (MWh)}\end{array} \times \begin{array}{c}\text{Unit cost of the i}^{\text{th}}\\ \text{hydro generator}\\ \text{(Rs/MWh)}\end{array}\right)$$

n = number of hydro generators connected

The hydro unit cost was not defined for large hydro power plants in Sri Lanka. The unit cost should reflect the economic aspects of hydro. So, the opportunity cost of each hydro plant (Rs/kWh) which is based on the water value (Rs/MCM) was used as the hydro unit cost. The Monthly opportunity costs of each hydro plant of 2019 were obtained from National System Control Centre, Ceylon Electricity Board. The opportunity cost is calculated from SDDP software at the National System Control Centre to prepare water management directives according to predicted inflows, the irrigation requirement, the water levels of the reservoirs and etc.

7.3.3 Startup costs difference between CASE A & B

$$\begin{matrix}\text{Startup} \\ \text{cost difference}\end{matrix} = \sum_{i=1}^{i=n} \begin{matrix}\text{Startup cost of the} \\ \text{i}^{\text{th}}\text{ thermal generator} \\ \text{in case A}\end{matrix} - \sum_{i=1}^{i=n} \begin{matrix}\text{Startup cost of the} \\ \text{i}^{\text{th}}\text{ thermal generator} \\ \text{in case B}\end{matrix}$$

n = number of thermal generators connected

7.3.4 Cost difference due to part load operation of hydro between CASE A & B

$$\begin{matrix}\text{Cost difference due to} \\ \text{part load operation} \\ \text{of hydro}\end{matrix} = \sum_{i=1}^{i=n} \left(\begin{matrix}\text{Difference of the} \\ \text{energy loss due to part} \\ \text{load operation of} \\ \text{i}^{\text{th}}\text{ hydro generator} \\ \text{between} \\ \text{case A \& B (MWh)}\end{matrix} \times \begin{matrix}\text{Unit cost of the i}^{\text{th}} \\ \text{hydro generator} \\ \text{(Rs/MWh)}\end{matrix} \right)$$

n = number of hydro generators connected

The opportunity cost of hydro storage was taken as the unit cost for calculations. When calculating the energy loss due to part load operation, the water discharge at nominal power of the hydro generator was considered as the reference. Water discharge at each MW set point of the generator was obtained from the discharge curves of each generator (Water discharge vs Power curves).

7.4 Calculation of cost of additional spinning reserve

Cost of additional spinning reserve was calculated for a day by dividing the day in to four sections namely off-peak time, morning time, day time and night time. Two case studies were performed for a hydro dominant day and for a thermal dominant day. Calculation steps using methods discussed in section 7.3.1 to 7.3.4 are explained in APPENDIX H.

7.4.1 Results

Calculated costs of additional spinning reserve for the hydro dominant case and for the thermal dominant case are shown in table 7-2 and 7-3.

Table 7-2: Additional cost of spinning reserve for a hydro dominant day

	Offpeak time	**Morning time**	**Day time**	**Night time**	**Total cost**
Thermal cost difference between CASE A & B (Rs.)	0	0	8,478,360	16,733,610	**25,211,970**
Hydro cost difference between CASE A & B (Rs.)	2,345,558	2,817,317	-4,201,162	-9,212,592	**-8,250,880**
Startup costs difference between CASE A & B (Rs.)	0	0	115,000	1,761,756	**1,876,756**
Cost difference due to part load operation of hydro between CASE A&B (Rs.)	875,456	389,466	923,689	927,880	**3,116,491**
Cost of additional spinning reserve (Rs.)	**3,221,013**	**3,206,783**	**5,315,887**	**10,210,654**	**21,954,337**

Table 7-3: Additional cost of spinning reserve for thermal dominant day

	Offpeak time	**Morning time**	**Day time**	**Night time**	**Total cost**
Thermal cost difference between CASE A & B (Rs)	-12,727,130	-10,260,680	445,680	-2,035,710	**-24,577,840**
Hydro cost difference between CASE A & B (Rs.)	19,497,137	13,973,040	7,841,124	6,982,635	**48,293,937**
Startup costs difference between CASE A & B (Rs.)	0	2,929,576	-208,000	0	**2,721,576**
Cost difference due to part load operation of hydro between CASE A&B (Rs.)	1,469,833	635,603	1,046,494	-146,610	**3,005,320**
Cost of additional spinning reserve (Rs.)	**8,239,840**	**7,277,539**	**9,125,298**	**4,800,315**	**29,442,993**

To visualize the size of these additional costs, comparison calculations should be performed.

7.5 Calculation of percentage increase in cost due to additional spinning reserve

Total operating cost of the day should be calculated in order to calculate the percentage increase in spinning reserve cost.

$$\begin{array}{c}\text{Total energy}\\ \text{cost}\end{array} = \sum_{i=1}^{i=n}\left(\begin{array}{c}\text{Energy from}\\ \text{i}^{\text{th}}\text{ generator (MWh)}\end{array} \times \begin{array}{c}\text{Unit cost of the i}^{\text{th}}\\ \text{generator (Rs/MWh)}\end{array}\right) + \sum_{i=1}^{i=n}\begin{array}{c}\text{Startup cost of the}\\ \text{i}^{\text{th}}\text{ generator (Rs.)}\end{array}$$

n = number of generators dispatched

Total operating cost calculations are explained in APPENDIX I.

$$\text{The total operating cost} = \begin{matrix}\text{The operating cost of}\\ \text{thermal generators}\end{matrix} + \begin{matrix}\text{The operating cost of}\\ \text{hydro generators}\end{matrix}$$

$$\text{Total operating cost for the hydro dominant day} = \text{Rs.}130{,}391{,}256 + \text{Rs.}301{,}052{,}523$$

$$\text{Total operating cost for the hydro dominant day} = \underline{\underline{\text{Rs. }431{,}443{,}779}}$$

$$\text{Total operating cost for the thermal dominant day} = \text{Rs.}582{,}326{,}681 + \text{Rs.}66{,}117{,}791$$

$$\text{Total operating cost for the thermal dominant day} = \underline{\underline{\text{Rs. }648{,}444{,}472}}$$

Using the results from the table 7-2 and 7-3, the percentage increase in the cost due to additional spinning reserve can be calculated.

Table 7-4: The percentage increase in the cost due to additional spinning reserve

	Total cost (Rs.)	**Additional cost for spinning reserve (Rs.)**	**% increase in cost**
Hydro dominant day	431,443,779	21,954,337	5%
Thermal dominant day	648,444,472	29,442,993	5%

It can be observed from the results that the percentage increase of cost due to additional spinning reserve is about 5% of the total cost.

7.6 The impact of additional spinning reserve to the unit generation cost

Total energy of the day can be calculated using the data in the table 7-1.

$$\text{Total energy of the day} = 1420\text{MW}\times 6.5\text{h} + 1660\text{MW}\times 4\text{h} + 2000\text{MW}\times 9\text{h} + 2200\text{MW}\times 4.5\text{h}$$

$$\text{Total energy of the day} = 43{,}770\ \text{MWh}$$

$$\begin{array}{c}\text{Cost increase per unit of generation} \\ \text{for the hydro dominant day}\end{array} = \frac{\text{Rs. }21{,}954{,}337}{43{,}770 \times 1000\text{kWh}}$$

$$\begin{array}{c}\text{Cost increase per unit of generation} \\ \text{for the hydro dominant day}\end{array} = 0.5\ \text{Rs/kWh}$$

$$\begin{array}{c}\text{Cost increase per unit of generation} \\ \text{for the thermal dominant day}\end{array} = \frac{\text{Rs. }29{,}442{,}993}{43{,}770 \times 1000\text{kWh}}$$

$$\begin{array}{c}\text{Cost increase per unit of generation} \\ \text{for the thermal dominant day}\end{array} = 0.67\ \text{Rs/kWh}$$

According to calculations, the cost of additional spinning reserve will be reflected as approximately 0.5-0.67 Rs/kWh in generation costs.

8 CONCLUSION AND RECOMMENDATIONS

8.1 Summary of the results

Minimizing impacts due to generation disconnections has two parts. One is minimizing effects during generation disconnection. The time period is typically from few seconds to several minutes. In this time period, the dominant factors are the system inertia, the frequency response of fast governors in the system and the damping of the power system. Other one is minimizing the effects after generation disconnection. This basically includes the amount of spinning reserve and the availability of fast starting generators.

As described in chapter 3, the present power system was modelled and validated. Then simulations were carried out, varying the total system generation and the amount of generation disconnection, and the frequency responses were observed. It was seen that the frequency response after a disconnection of generators is better in a thermal dominant case than in a hydro dominant case due to the higher system inertia in the thermal dominant case. When the total generation increases, the frequency response improves but the improvement was not significant enough to avoid the dependency on under frequency load shedding during generation disconnections.

In chapter 4, the impact of inverter, converter-based generation on the frequency response was studied. The amount of wind penetration was increased and the frequency response was observed during generation disconnections. The frequency nadir and the rate of change of frequency (ROCOF) were increased, when the amount of wind penetration was increased. There is a tendency of absorbing more non-conventional renewable energy (NCRE) generation to the power system of Sri Lanka in the future. Even though the total system generation increased, the frequency response may not improve due to the high penetration of inverter, converter-based generation. Rotating generators and motors are components of the power system which provide the power system inertia. That means if a generation disconnection occurred, synchronous generators and motors in the system will contribute by reducing their kinetic energy in order to supply loads temporarily. In turn, it will improve the frequency response. Large power systems are connected with more synchronously rotating generators and motors unlike in the case of Sri Lanka. This makes them resilient during generator disconnections. The power system of Sri Lanka is an islanded, a comparatively small power system with comparatively a smaller number of synchronously rotating masses. These factors contribute toward a low power system inertia in the power system and a reduced frequency response. Introduction of NCREs has made the situation worse. A conventional way to minimize the impact would be to introduce thermal generators with high inertia replacing low inertia generators. Viability of new technologies should be studied to come to a modern-day solution.

In chapter 5, impact of battery energy storage systems (BESS) on the frequency response was studied. It was observed that the frequency nadir improved significantly with the support of a BESS due to the low ramp time of the BESS. Unlike in large power systems, the BESS provided a substantial improvement in the frequency response. By selecting a proper control logic, a BESS can give its optimum contribution to the power system frequency regulation during generation disconnections.

In chapter 6, a cost analysis for BESS was performed for the power system of Sri Lanka. The cost of a unit delivered from BESS would be around 36-45 Rs/kWh in 2025, 32-42 Rs/kWh in 2030 and 28-37 Rs/kWh in 2050 for a 4-hour BESS system of 100 MW (Assuming 4-hour operation daily). The cost for energy storing only would be around 13-23 Rs/kWh in 2030 as the charging cost is assumed 19 Rs/kWh. It was also found that usage of BESS only for the emergency frequency correcting purpose is not an economical option due to high capital costs of BESS. For 1-hour and 2-hour BESS systems, the cost didn’t show a significant difference compared to the 4-hour BESS system.

In chapter 7, Minimizing the impact after a generation disconnection with spinning reserve was analyzed. Case studies for the spinning reserve were performed to evaluate additional costs if the spinning reserve was maintained at the largest generator size connected. It was observed from results that the percentage increase in the cost due to additional spinning reserve is about 5% of the total cost according to the considered cases. It was also found that the cost of additional spinning reserve will be reflected as approximately 0.5-0.67 Rs/kWh in generation costs.

8.2 Conclusion

It is clear that the future power system of Sri Lanka will also depend on under-frequency load shedding if adequate measures were not taken. But in some countries, any kind of load disconnection for credible events are demoted. According to the inherent characteristics of the power system in Sri Lanka, it has been difficult to avoid the impact on consumers during generation disconnections. Connecting more inverter, converter-based generation will further reduce the system inertia.

Battery energy storage systems can improve the frequency response significantly during generator disconnections. A BESS can also reduce the amount of spinning reserve to be kept while providing 2-3 hours to start generators after large generation disconnections. With the growth of the system demand, the prominence of hydro will be diminished since almost all possible large hydro plants are commissioned or under construction by now. The future conventional sources may be combined cycle plants, steam turbines which will take more time to start after generation disconnections. In that case, A BESS will be useful.

As discussed in sections 6.5, 6.6, 6.7 and 6.8, utilizing BESS only to avoid UFLS is not an economical option. However, if BESS utilizes its designed number of operating hours a day combining it with other purposes such as load shifting, wind, solar intermittency control, peaking support, a BESS may be a feasible option in the future. Additionally, it provides spinning reserve support without delivering the active power to the system.

In hydro limited, dry season, opportunity costs of hydro generation are very high. If more hydro is dispatched for spinning reserve, marginal costs would be very high and there will be practical issues to dispatch more hydro due to low reservoir levels as well. That makes BESS an attractive option.

8.3 Recommendations

1. Minimum limits of kinetic energy or inertia from generators can be added to the operation code. The system operator can be empowered to disconnect certain

generation and add supportive generation to keep the system inertia of the power system within limits

2. BESS can be considered to reduce the frequency nadir during generator disturbances. BESS can also be used to reduce the amount of spinning reserve as well. However, using BESS only during frequency disturbances is not economical.

3. BESS can be utilized for multiple purposes for e.g. load shifting, solar PV, wind intermittency control, load frequency control, as fast frequency reserve. It may make BESS an economically attractive option.

4. Policies related to spinning reserve can be reconsidered based on the additional cost to maintain spinning reserve at an internationally practiced level.

5. Standards can be set by generation planners when procuring thermal generators to consider generators with adequate ramp times to provide adequate spinning reserve. Thermal generators which can provide spinning reserve is lacking in the present power system.

8.4 Recommendations for the future work

1. Optimal Sizing of battery energy storage system for the power system Sri Lanka.

   In this study, the sizing of BESS was not considered. However, if BESS is to be implemented, the sizing of BESS should be determined. Purposes of BESS installation should be identified to determine the sizing. Purposes can be inertia support, fast frequency regulation or combination of both, peak support, wind, solar intermittency control and etc. [19]
2. Derivative of frequency control (ROCOF) mode modelling of BESS for the power system of Sri Lanka.

A BESS can be modelled dynamically in droop control mode or in derivative of frequency control mode or a combination of the both.

In this study, the modelling was based on droop control mode which regulates the active power based on frequency variations [5]. It acts more as a fast frequency regulator.

If a BESS is modelled in derivative of frequency control mode, it regulates active power based on the ROCOF which will act more as an inertia emulator [5]. In each mode, the BESS performs different jobs. Advantages and disadvantages of each mode can be studied for the power system of Sri Lanka.

3. Study on the synthetic inertia from wind generators for improved inertia response for the power system of Sri Lanka.

   Wind turbines inherently have a substantial amount of inertia which has been isolated from the main grid due to power electronics in between. This inertia in wind turbines can be utilized by adding additional control loops. In other words, kinetic energy from the wind plant can be converted to supply loads for a short duration during a frequency disturbance by programming the control logic. This is called synthetic inertia.

   This synthetic inertia will be useful when the system is lacking synchronous generators to provide support for the system inertia.

REFERENCES

[1] Australian Energy Market Operator Ltd, “Power System Security Guidelines,” September 2019, [online], available at: https//www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3715---Power-System-Security-Guidelines.pdf

[2] EIRGRID, “Transmission System Security and Planning Standards,” May 2016, [online], available at: http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-Transmission-System-Security-and-Planning-Standards-TSSPS-Final-May-2016-APPROVED.pdf

[3] INOGATE, “Electricity Transmission Security Standards in Armenia,” September 2014, [online], available at: https//http://www.inogate.org/documents/AM45.pdf

[4] Ceylon Electricity Board, “Statistical Digest 2018,” [online], available at: https://ceb.lk/publication-media/statistical-reports/80/en

[5] Lucas Thomée, “Lithium-Ion Battery Storage for Frequency Control,” Sweden 2018, [online], available at: http://publications.lib.chalmers.se/records/fulltext/255343/255343.pdf, Department of Electrical Engineering, Chalmers University of Technology, Gothenburg

[6] Siemens, “PSS®E Model Library,” Siemens Industry, Inc, October 2013

[7] P. V. Brogan, R. Best, D. J. Morrow, A. Alikhanzadeh and M. Kubik, "Per Unit Displacement of Synchronous Inertia with BESS Synthetic Inertia Devices," 2018 IEEE Power & Energy Society General Meeting (PESGM), Portland, OR, 2018, pp. 1-5, doi: 10.1109/PESGM.2018.8586323

[8] K Mongird, V Fotedar, V Viswanathan, V Koritarov, P Balducci, B Hadjerioua, J Alam, “Energy Storage Technology and Cost Characterization Report,” Pacific Northwest National Laboratory, July 2019, [online], available at: https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf

[9] Wesley Cole, A. Will Frazier, “Cost Projections for Utility-Scale Battery Storage: 2020 Update,” National Renewable Energy Laboratory, June 2020

[10] Sangwook Han, A study on alternative method of self – starting generator using ESS, Journal of International Council on Electrical Engineering, 2019, 9:1, 1-7, DOI: 10.1080/22348972.2018.1558921

[11] LAZARD, “Lazard’s Levelized Cost of Storage Analysis Version-5.0” November 2019, [online], available at: https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf

[12] Shruti M. Deorah, Nikit Abhyankar, Siddharth Arora, Ashwin Gambhir, Amol Phadke,“Estimating the Cost of Grid-Scale Lithium-Ion Battery Storage in India”, April 2019, [online], available at: https://eta-publications.lbl.gov/sites/default/files/lbnl-2001314.pdf

[13] R. S. Ranjitha, “Determination of Maximum Possible Loading Capacity of a Single Generator Unit: A Case Study for The Present Sri Lankan Power System,” M.Sc. thesis, University of Moratuwa, January 2018, [online], available at: https//dl.lib.mrt.ac.lk/handle/123/13319

[14] G. Kishokumar, “Designing Automatic Load-Frequency Control Scheme for Sri Lankan Power System,” M.Sc. thesis, University of Moratuwa, April 2018, [online], available at: https//dl.lib.mrt.ac.lk/handle/123/13325

[15] K. H. E. H. Jayarathna, “Technical and Economic Impacts of the First Coal-fired Power Station in Sri Lanka,” M.Sc. thesis, University of Gävle, May 2015, [online], available at: http://www.diva-portal.org/smash/get/diva2:812764/FULLTEXT01.pdf

[16] F. Gonzalez-Longatt, E. Chikuni, W. Stemmet and K. Folly, "Effects of the synthetic inertia from wind power on the total system inertia after a frequency disturbance," IEEE Power and Energy Society Conference and Exposition in Africa: Intelligent Grid Integration of Renewable Energy Resources (PowerAfrica), Johannesburg, 2012, pp. 1-7, doi: 10.1109/PowerAfrica.2012.6498636.

[17] Dr. L. N. Widanagama Arachchige, Prof. J. R. Lucas, Ms. M. S. Nakandala, “Generation Cost Optimization through a Network Stability Study,” July 2016, [online], available at: https://www.pucsl.gov.lk/wp-content/uploads/2020/06/2016-Final-report-stability-study-to-PUCSL-07-07-2016-1.pdf

[18] Ceylon Electricity Board, “National System Control Centre Annual Report 2019,” May 2020

[19] V. Knap, S. K. Chaudhary, D. Stroe, M. Swierczynski, B. Craciun and R. Teodorescu, "Sizing of an Energy Storage System for Grid Inertial Response and Primary Frequency Reserve," in IEEE Transactions on Power Systems, vol. 31, no. 5, pp. 3447-3456, Sept. 2016, doi: 10.1109/TPWRS.2015.2503565.

[20] Public utilities commission of Sri Lanka, “Study Report on Use of Battery Energy Storage Systems”, Nov 2015, [online], available at: https://www.pucsl.gov.lk/wp-content/uploads/2017/10/Study-Report-on-Use-of-Battery-Energy-Storage-Systems.pdf

[21] M. C. Such and G. Y. Masada, "BESS control on an microgrid with significant wind generation," *2017 IEEE Power & Energy Society General Meeting*, Chicago, IL, USA, 2017, pp. 1-5, doi: 10.1109/PESGM.2017.8274644.

[22] Son, Dae-Hee & Ali, Muhammad & Kang, Sang-Hee & Heo, Jae-Haeng & Nam, Soon-Ryul. (2018). A Method for Increasing the Operating Limit Capacity of Wind Farms Using Battery Energy Storage Systems with Rate of Change of Frequency. Energies. 11. 758. 10.3390/en11040758.

APPENDIX A

Table 1: Plant-wise generation at the tripping of WCP 130 MW at 9:19 hours on 17 Jul 2019

Power Plant	**Output (MW)**	**Output (Mvar)**
Canyon	10.1	1.0
Old Laxapana	4.1	1.2
New Laxapana	39.0	30.9
Polpitiya	14.0	11.2
Kotmale	54.1	12.3
Randenigala	37.0	3.4
Rantambe	15.3	4.7
Kukule ganga	52.0	0.0
Lakvijaya unit 01	201.8	27.5
Lakvijaya unit 02	270.8	-2.0
Lakvijaya unit 03	271.7	8.6
Sapugaskanda A	53.9	17.6
Sapugaskanda B	53.1	29.8
Barge	60.4	25.9
Uthurujanani	13.7	2.5
Kelanithissa CCP	100.6	47.8
Supplimentary-Kolonnawa	14.4	0.0
Supplimentary-Thulhiriya	4.0	0.0
Kelanithissa GT 07	110.9	23.6
Kelanithissa small GTs	33.2	0.9
WCP	133.0	42.8
Sojitz	156.6	23.1
Ace-Embilipitiya	82.1	1.3
Asia power	45.9	9.1
Ace-Matara	20.0	0.0
Diesel-Mahiyangana	9.4	4.1
Diesel-Hambanthota	20.8	8.8
Diesel-Horana	20.4	0.0
Diesel-Polonnaruwa	8.2	1.8
Diesel-Pallekelle	24.3	6.2
Diesel-Galle	10.5	0.0
NCRE	8.7	1.5
Total	**1954.2**	**345.6**

Table 2: Plant-wise generation at the tripping of Lakvijaya unit 03 200 MW at 21:10 hours on 21 Sep 2019

Power Plant	**Output (MW)**	**Output (Mvar)**
Wimalasurendra	15.0	-0.7
Canyon	48.0	3.4
Old Laxapana	52.2	-0.9
New Laxapana	107.7	5.9
Polpitiya	87.5	2.2
Upper Kotmale	110.7	23.2
Kotmale	37.4	12.4
Victoria	240.1	43.1
Randenigala	120.6	13.9
Rantembe	53.2	5.8
Ukuwela	36.0	0.0
Bowatenna	39.4	4.3
Samanalawewa	98.6	8.0
Kukule ganga	37.5	2.0
Lakvijaya unit 02	268.3	21.4
Lakvijaya unit 03	201.3	21.4
Sapugaskanda A	51.1	5.4
Sapugaskanda B	60.1	14.6
Barge	59.9	7.9
Uthurujanani	21.3	-2.9
NCRE	24.6	3.5
Total	**1770.4**	**193.9**

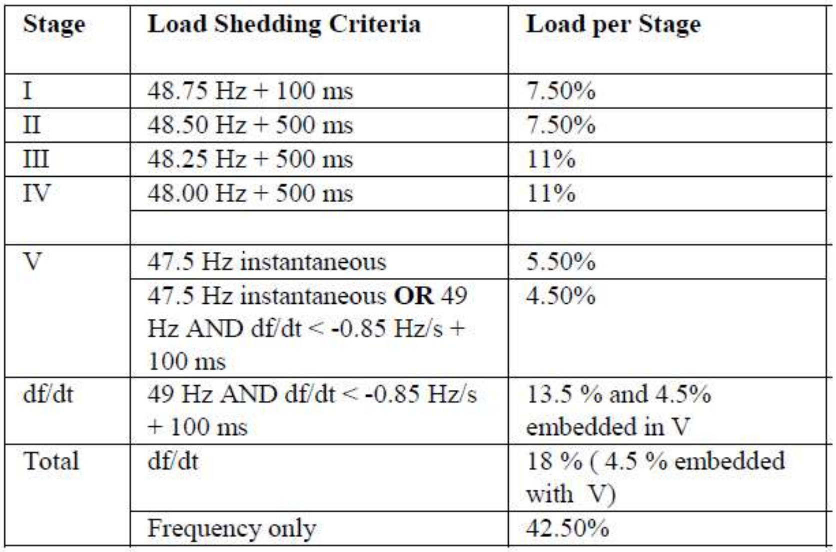
APPENDIX B

Table 3: Plant-wise generation for Simulation example: Disconnection of 270 MW of 2000 MW of total system generation – Hydro dominant case

Power Plant	**Output (MW)**
Wimalasurendra	30
Canyon	30
Old Laxapana	51
New Laxapana	107
Polpitiya	80
Upper Kotmale	150
Kotmale	195
Victoria	122
Randenigala	120
Rantembe	30
Ukuwela	36
Bowatenna	25
Samanalawewa	80
Kukule ganga	74
Lakvijaya unit 01	270
Lakvijaya unit 02	270
Lakvijaya unit 03	270
NCRE	60
Total	**2000**

APPENDIX C

Table 4: Under-frequency load shedding scheme as of November 2020



Stage	**Load Shedding Criteria**	**Load per Stage**
I	48.75 Hz + 100 ms	7.50%
II	48.50 Hz + 500 ms	7.50%
III	48.25 Hz + 500 ms	11%
IV	48.00 Hz + 500 ms	11%
V	47.5 Hz instantaneous	5.50%
	47.5 Hz instantaneous **OR** 49 Hz AND df/dt < -0.85 Hz/s + 100 ms	4.50%
df/dt	49 Hz AND df/dt < -0.85 Hz/s + 100 ms	13.5 % and 4.5% embedded in V
Total	df/dt	18 % (4.5 % embedded with V)
	Frequency only	42.50%

APPENDIX D

Table 5: Unit-wise generation for CASE 1 simulations with zero wind penetration

	Unit	MW		Unit	MW		Unit	MW
Wimalasurendra	1	10	Kelanithissa	1	33	Mannar wind park 1	1	0
	2	0		2	0		2	0
Canyon	1	20	Galle	1	100		3	0
	2	0	Embilipitiya	1	100		4	0
Old Laxapana	1	9	Barge	1	60		5	0
	2	9	Kerawalapitiya CCP1	G1	100		6	0
	3	9		G2	100		7	0
	4	12		ST	100	Mannar wind park 2	1	0
	5	12	Kerawalapitiya CCP2	G1	100		2	0
New Laxapana	1	40		G2	100		3	0
	2	57		ST	100		4	0
Polpitiya	1	40	KPS GT 07		0		5	0
	2	40	Kelanithissa CCP	GT	109		6	0
Samanalawewa	1	60		ST	54		7	0
	2	0	Sojitz	GT	100	Mannar wind park 3	1	0
Kukule ganga	1	37		ST	60		2	0
	2	0	WCP	GT1	85		3	0
Upper Kotmale	1	0		GT2	85	Pooneryn wind park	1	0
	2	75		ST	90		2	0
Kotmale	1	0	Sapugaskanda A		72		3	0
	2	65	Sapugaskanda B1		36		4	0
	3	65	Sapugaskanda B2		36		5	0
Victoria	1	42	Lakvijaya	1	270		6	0
	2	0		2	270			
	3	0		3	270			
Randenigala	1	0		4	270			
	0	60	Horana diesel		0			
Rantembe	1	0	Pallekelle diesel		0			
	2	25	Matara diesel		0			
Ukuwela	1	18						
	2	18						
Bowatenna	1	37						
Uma oya	1	40						
	2	0						
TOTAL HYDRO		**800**	**TOTAL THERMAL**		**2700**	**TOTAL WIND**		**0**
TOTAL GENERATION		**3500**						

Table 6: Unit-wise generation for CASE 2 simulations with 100MW wind penetration

	Unit	MW		Unit	MW		Unit	MW
Wimalasurendra	1	10	Kelanithissa	1	28	Mannar wind park 1	1	20
	2	0		2	0		2	15
Canyon	1	20	Galle	1	0		3	15
	2	0	Embilipitiya	1	100		4	15
Old Laxapana	1	9	Barge	1	60		5	20
	2	9	Kerawalapitiya CCP1	G1	100		6	15
	3	9		G2	100		7	0
	4	12		ST	100	Mannar wind park 2	1	0
	5	12	Kerawalapitiya CCP2	G1	100		2	0
New Laxapana	1	40		G2	100		3	0
	2	57		ST	100		4	0
Polpitiya	1	40	KPS GT 07		0		5	0
	2	40	Kelanithissa CCP	GT	109		6	0
Samanalawewa	1	60		ST	54		7	0
	2	0	Sojitz	GT	104	Mannar wind park 3	1	0
Kukule ganga	1	37		ST	61		2	0
	2	0	WCP	GT1	85		3	0
Upper Kotmale	1	0		GT2	85	Pooneryn wind park	1	0
	2	75		ST	90		2	0
Kotmale	1	0	Sapugaskanda A		72		3	0
	2	65	Sapugaskanda B1		36		4	0
	3	65	Sapugaskanda B2		36		5	0
Victoria	1	42	Lakvijaya	1	270		6	0
	2	0		2	270			0
	3	0		3	270			0
Randenigala	1	0		4	270			0
	0	60	Horana diesel		0			0
Rantembe	1	0	Pallekelle diesel		0			0
	2	25	Matara diesel		0			0
Ukuwela	1	18			0			0
	2	18			0			0
Bowatenna	1	37			0			0
Uma oya	1	40			0			0
	2	0			0			0
TOTAL HYDRO		**800**	**TOTAL THERMAL**		**2600**	**TOTAL WIND**		**100**
TOTAL GENERATION		**3500**						

Table 7: Unit-wise generation for CASE 3 simulations with 200 MW wind penetration

	Unit	MW		Unit	MW		Unit	MW
Wimalasurendra	1	10	Kelanithissa	1	0	Mannar wind park 1	1	20
	2	0		2	0		2	15
Canyon	1	20	Galle	1	0		3	15
	2	0	Embilipitiya	1	28		4	15
Old Laxapana	1	9	Barge	1	60		5	20
	2	9	Kerawalapitiya CCP1	G1	100		6	15
	3	9		G2	100		7	20
	4	12		ST	100	Mannar wind park 2	1	15
	5	12	Kerawalapitiya CCP2	G1	100		2	20
New Laxapana	1	40		G2	100		3	20
	2	57		ST	100		4	10
Polpitiya	1	40	KPS GT 07		0		5	15
	2	40	Kelanithissa CCP	GT	109		6	0
Samanalawewa	1	60		ST	54		7	0
	2	0	Sojitz	GT	104	Mannar wind park 3	1	0
Kukule ganga	1	37		ST	61		2	0
	2	0	WCP	GT1	85		3	0
Upper Kotmale	1	0		GT2	85	Pooneryn wind park	1	0
	2	75		ST	90		2	0
Kotmale	1	0	Sapugaskanda A		72		3	0
	2	65	Sapugaskanda B1		36		4	0
	3	65	Sapugaskanda B2		36		5	0
Victoria	1	42	Lakvijaya	1	270		6	0
	2	0		2	270			0
	3	0		3	270			0
Randenigala	1	0		4	270			0
	0	60	Horana diesel		0			0
Rantembe	1	0	Pallekelle diesel		0			0
	2	25	Matara diesel		0			0
Ukuwela	1	18			0			0
	2	18			0			0
Bowatenna	1	37			0			0
Uma oya	1	40			0			0
	2	0			0			0
TOTAL HYDRO		**800**	**TOTAL THERMAL**		**2500**	**TOTAL WIND**		**200**
TOTAL GENERATION		**3500**						

Table 8: Unit-wise generation for CASE 4 simulations with 300 MW wind penetration

	Unit	MW		Unit	MW		Unit	MW
Wimalasurendra	1	10	Kelanithissa	1	0	Mannar wind park 1	1	20
	2	0		2	0		2	15
Canyon	1	20	Galle	1	0		3	15
	2	0	Embilipitiya	1	0		4	15
Old Laxapana	1	9	Barge	1	0		5	20
	2	9	Kerawalapitiya CCP1	G1	100		6	15
	3	9		G2	100		7	20
	4	12		ST	100	Mannar wind park 2	1	15
	5	12	Kerawalapitiya CCP2	G1	100		2	20
New Laxapana	1	40		G2	100		3	20
	2	57		ST	100		4	10
Polpitiya	1	40	KPS GT 07		0		5	15
	2	40	Kelanithissa CCP	GT	109		6	15
Samanalawewa	1	60		ST	54		7	20
	2	0	Sojitz	GT	104	Mannar wind park 3	1	15
Kukule ganga	1	37		ST	61		2	15
	2	0	WCP	GT1	85		3	15
Upper Kotmale	1	0		GT2	85	Pooneryn wind park	1	10
	2	75		ST	90		2	10
Kotmale	1	0	Sapugaskanda A		60		3	0
	2	65	Sapugaskanda B1		36		4	0
	3	65	Sapugaskanda B2		36		5	0
Victoria	1	42	Lakvijaya	1	270		6	0
	2	0		2	270			0
	3	0		3	270			0
Randenigala	1	0		4	270			0
	0	60	Horana diesel		0			0
Rantembe	1	0	Pallekelle diesel		0			0
	2	25	Matara diesel		0			0
Ukuwela	1	18			0			0
	2	18			0			0
Bowatenna	1	37			0			0
Uma oya	1	40			0			0
	2	0			0			0
TOTAL HYDRO		**800**	**TOTAL THERMAL**		**2400**	**TOTAL WIND**		**300**
TOTAL GENERATION		**3500**						

Table 9: Unit-wise generation for CASE 5 simulations with 400 MW wind penetration

	Unit	MW		Unit	MW		Unit	MW
Wimalasurendra	1	10	Kelanithissa	1	0	Mannar wind park 1	1	20
	2	0		2	0		2	15
Canyon	1	20	Galle	1	0		3	15
	2	0	Embilipitiya	1	0		4	15
Old Laxapana	1	9	Barge	1	53		5	20
	2	9	Kerawalapitiya CCP1	G1	100		6	15
	3	9		G2	100		7	20
	4	12		ST	100	Mannar wind park 2	1	15
	5	12	Kerawalapitiya CCP2	G1	100		2	20
New Laxapana	1	40		G2	100		3	20
	2	57		ST	100		4	10
Polpitiya	1	40	KPS GT 07		0		5	20
	2	40	Kelanithissa CCP	GT	109		6	20
Samanalawewa	1	60		ST	54		7	20
	2	0	Sojitz	GT	0	Mannar wind park 3	1	15
Kukule ganga	1	37		ST	0		2	15
	2	0	WCP	GT1	85		3	15
Upper Kotmale	1	0		GT2	85	Pooneryn wind park	1	20
	2	75		ST	90		2	20
Kotmale	1	0	Sapugaskanda A		72		3	20
	2	65	Sapugaskanda B1		36		4	10
	3	65	Sapugaskanda B2		36		5	20
Victoria	1	42	Lakvijaya	1	270		6	20
	2	0		2	270			0
	3	0		3	270			0
Randenigala	1	0		4	270			0
	0	60	Horana diesel	0				0
Rantembe	1	0	Pallekelle diesel	0				0
	2	25	Matara diesel	0				0
Ukuwela	1	18		0				0
	2	18		0				0
Bowatenna	1	37		0				0
Uma oya	1	40		0				0
	2	0		0				0
TOTAL HYDRO		**800**	**TOTAL THERMAL**		**2300**	**TOTAL WIND**		**400**
TOTAL GENERATION		**3500**						

Table 10: Unit-wise generation for CASE 6 simulations with 500 MW wind penetration

	Unit	MW		Unit	MW		Unit	MW
Wimalasurendra	1	10	Kelanithissa	1	0	Mannar wind park 1	1	21
	2	0		2	0		2	24
Canyon	1	20	Galle	1	0		3	24
	2	0	Embilipitiya	1	56		4	14
Old Laxapana	1	9	Barge	1	60		5	24
	2	9	Kerawalapitiya CCP1	G1	100		6	21
	3	9		G2	100		7	24
	4	12		ST	100	Mannar wind park 2	1	21
	5	12	Kerawalapitiya CCP2	G1	100		2	24
New Laxapana	1	40		G2	100		3	24
	2	57		ST	100		4	14
Polpitiya	1	40	KPS GT 07		0		5	24
	2	40	Kelanithissa CCP	GT	0		6	20
Samanalawewa	1	60		ST	0		7	24
	2	0	Sojitz	GT	0	Mannar wind park 3	1	24
Kukule ganga	1	37		ST	0		2	24
	2	0	WCP	GT1	85		3	24
Upper Kotmale	1	0		GT2	85	Pooneryn wind park	1	20
	2	75		ST	90		2	24
Kotmale	1	0	Sapugaskanda A		72		3	24
	2	65	Sapugaskanda B1		36		4	13
	3	65	Sapugaskanda B2		36		5	24
Victoria	1	42	Lakvijaya	1	270		6	20
	2	0		2	270			0
	3	0		3	270			0
Randenigala	1	0		4	270			0
	0	60	Horana diesel		0			0
Rantembe	1	0	Pallekelle diesel		0			0
	2	25	Matara diesel		0			0
Ukuwela	1	18			0			0
	2	18			0			0
Bowatenna	1	37			0			0
Uma oya	1	40			0			0
	2	0			0			0
TOTAL HYDRO		**800**	**TOTAL THERMAL**		**2200**	**TOTAL WIND**		**500**
TOTAL GENERATION		**3500**						

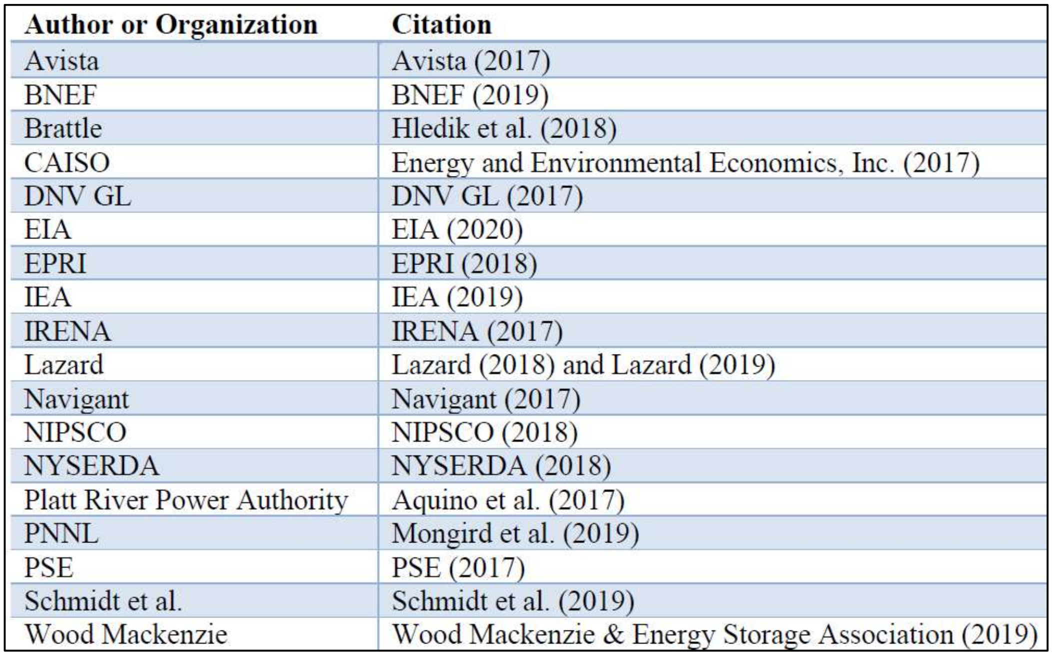
APPENDIX E

Table 11: Plant-wise generation used for the Battery Energy Storage System simulation

Power Plant	**Total Output (MW)**
Wimalasurendra	30
Canyon	30
Old Laxapana	51
New Laxapana	107
Polpitiya	80
Upper Kotmale	150
Kotmale	195
Victoria	122
Randenigala	120
Rantembe	30
Ukuwela	36
Bowatenna	25
Samanalawewa	80
Kukule ganga	74
Lakvijaya unit 01	270
Lakvijaya unit 02	270
Lakvijaya unit 03	270
NCRE	60
Total	**2000**

APPENDIX F

Table 12: List of publications used to determine battery cost and performance projections by NREL [9]



Author or Organization	**Citation**
Avista	Avista (2017)
BNEF	BNEF (2019)
Brattle	Hledik et al. (2018)
CAISO	Energy and Environmental Economics, Inc. (2017)
DNV GL	DNV GL (2017)
EIA	EIA (2020)
EPRI	EPRI (2018)
IEA	IEA (2019)
IRENA	IRENA (2017)
Lazard	Lazard (2018) and Lazard (2019)
Navigant	Navigant (2017)
NIPSCO	NIPSCO (2018)
NYSERDA	NYSERDA (2018)
Platt River Power Authority	Aquino et al. (2017)
PNNL	Mongird et al. (2019)
PSE	PSE (2017)
Schmidt et al.	Schmidt et al. (2019)
Wood Mackenzie	Wood Mackenzie & Energy Storage Association (2019)

APPENDIX G

Table 13: Economic dispatch with spinning reserve equal to the size of the largest generator – for a hydro dominant day (CASE A)

Hydro dominant dispatch with spinning reserve of the size of the largest generator for a day					
Generator	**Unit**	**Off peak**	**Morning time**	**Day time**	**Night time**
Wimalasurendra	1	25	20	25	15
	2	0	20	25	15
Canyon	1	20	20	25	15
	2	20	10	25	15
Old Laxapana	1	9	9	9	9
	2	9	9	9	9
	3	9	9	9	9
	4	12	12	12	12
	5	12	12	12	12
New Laxapana	1	50	50	50	50
	2	57	57	57	57
Polpitiya	1	40	40	40	43
	2	40	40	40	43
Samanalawewa	1	40	40	40	40
	2	40	40	40	40
Kukule ganga	1	0	0	37	37
	2	0	0	37	37
Upper Kotmale	1	0	75	75	75
	2	0	75	75	75
Kotmale	1	30	0	41	30
	2	0	30	50	30
	3	0	30	50	67
Victoria	1	30	44	20	30
	2	30	35	20	30
	3	34	70	20	30
Randenigala	1	60	60	60	60
	0	60	60	60	60
Rantembe	1	25	25	20	25
	2	25	25	20	25
Ukuwela	1	18	18	18	18
	2	18	18	18	18
Bowatenna	1	37	37	37	37
Lakvijaya	1	200	200	270	270
	2	200	200	270	270
	3	200	200	270	270
Sapugaskanda B	5	0	0	9	9
	6	0	0	9	9
	7	0	0	9	9
	8	0	0	9	9
	9	0	0	8	9
	10	0	0	0	9
	11	0	0	0	9
	12	0	0	0	9
Barge		0	0	0	60
WCP		0	0	0	130
NCRE		70	70	70	60
Total generation		**1420**	**1660**	**2000**	**2200**

Table 14: Economic dispatch with 5% of spinning reserve – for a hydro dominant day (CASE B)

Hydro dominant dispatch with 5% of spinning reserve for a day					
Generator	**Unit**	**Off peak**	**Morning time**	**Day time**	**Night time**
Wimalasurendra	1	25	20	25	15
	2	0	0	0	15
Canyon	1	20	20	25	15
	2	20	0	0	15
Old Laxapana	1	9	9	9	9
	2	9	9	9	9
	3	9	9	9	9
	4	12	12	12	12
	5	12	12	12	12
New Laxapana	1	50	50	50	50
	2	57	57	57	57
Polpitiya	1	40	40	40	43
	2	40	40	40	43
Samanalawewa	1	40	40	40	40
	2	40	40	40	40
Kukule ganga	1	0	0	37	37
	2	0	0	37	37
Upper Kotmale	1	0	75	75	75
	2	0	75	75	75
Kotmale	1	0	0	67	67
	2	0	0	67	67
	3	0	30	67	67
Victoria	1	54	69	44	54
	2	70	70	50	70
	3	0	70	0	60
Randenigala	1	60	60	60	60
	0	60	60	60	60
Rantembe	1	25	25	20	25
	2	25	25	20	25
Ukuwela	1	18	18	18	18
	2	18	18	18	18
Bowatenna	1	37	37	37	37
Lakvijaya	1	200	200	270	270
	2	200	200	270	270
	3	200	200	270	270
Sapugaskanda B	5	0	0	0	9
	6	0	0	0	9
	7	0	0	0	9
	8	0	0	0	9
	9	0	0	0	7
	10	0	0	0	7
	11	0	0	0	7
	12	0	0	0	7
Barge		0	0	0	30
WCP		0	0	0	0
NCRE		70	70	70	60
Total generation		**1420**	**1660**	**2000**	**2200**

Table 15: Economic dispatch with spinning reserve equal to the size of the largest generator – for a thermal dominant day (CASE A)

Thermal dominant dispatch with spinning reserve of the size of the largest generator for a day					
Generator	**Unit**	**Off peak**	**Morning time**	**Day time**	**Night time**
Old Laxapana	1	0	0	0	0
	2	0	0	0	0
	3	0	0	0	0
	4	0	0	0	0
	5	10	10	10	10
New Laxapana	1	25	25	0	0
	2	0	0	12	10
Polpitiya	1	0	0	0	0
	2	10	10	20	10
Kotmale	1	30	30	0	30
	2	30	30	0	0
	3	30	30	0	0
Victoria	1	32	55	30	50
	2	20	20	20	40
	3	0	0	20	40
Kelanithissa GT	7	0	0	0	82
Kelanithissa CCP	GT	90	90	90	90
	ST	60	60	60	60
Lakvijaya	1	270	270	270	270
	2	270	270	270	270
	3	270	270	270	270
Sapugaskanda A	1	16	13	16	16
	2	16	12	16	16
	3	16	11	16	16
	4	16	11	16	16
Sapugaskanda B	5	9	9	9	9
	6	9	9	9	9
	7	9	9	9	9
	8	9	9	9	9
	9	9	9	9	9
	10	9	9	9	9
	11	9	9	9	9
	12	9	9	9	9
Uthurujanani		17	0	24	24
Barge		60	60	60	60
Ace Matara		0	0	24	24
Diesel private		0	0	100	100
Asia Power		0	0	48	48
Sojitz CCP		0	143	153	153
ACE Embilipitiya		0	0	93	93
WCP		0	108	220	220
CEB Supplementary		0	0	10	50
NCRE		60	60	60	60
Total generation		**1420**	**1660**	**2000**	**2200**

Table 16: Economic dispatch with 5% of spinning reserve – for a thermal dominant day (CASE B)

Thermal dominant dispatch with 5% of spinning reserve for a day

Generator	**Unit**	**Off peak**	**Morning time**	**Day time**	**Night time**
Old Laxapana	1	0	0	0	0
	2	0	0	0	0
	3	0	0	0	0
	4	0	0	0	0
	5	10	0	10	10
New Laxapana	1	25	10	0	0
	2	0	0	12	10
Polpitiya	1	0	0	0	0
	2	10	10	20	10
Kotmale	1	0	0	0	0
	2	0	0	0	0
	3	0	0	0	0
Victoria	1	49	55	40	50
	2	0	0	0	60
	3	0	0	0	0
Kelanithissa GT	7	0	0	0	72
Kelanithissa CCP	GT	90	90	100	90
	ST	60	60	60	60
Lakvijaya	1	270	270	270	270
	2	270	270	270	270
	3	270	270	270	270
Sapugaskanda A	1	11	0	16	16
	2	0	0	16	16
	3	0	0	16	16
	4	0	0	16	16
Sapugaskanda B	5	9	9	9	9
	6	9	9	9	9
	7	9	9	9	9
	8	9	9	9	9
	9	9	9	9	9
	10	9	9	9	9
	11	9	9	9	9
	12	9	9	9	9
Uthurujanani		0	0	24	24
Barge		60	60	60	60
Ace Matara		0	0	24	24
Diesel private		0	0	70	100
Asia Power		0	0	48	48
Sojitz CCP		163	163	163	163
ACE Embilipitiya		0	0	93	93
WCP		0	270	270	270
CEB Supplementary		0	0	0	50
NCRE		60	60	60	60
Total generation		**1420**	**1660**	**2000**	**2200**

APPENDIX H

A calculation example of the cost of additional spinning reserve of day time for the hydro dominant day is explained

$$\begin{array}{l}\text{Cost for}\\ \text{additional}\\ \text{spinning}\\ \text{reserve}\end{array} = \begin{array}{l}\text{Thermal cost}\\ \text{difference}\\ \text{between}\\ \text{CASE A\&B}\end{array} + \begin{array}{l}\text{Hydro cost}\\ \text{difference}\\ \text{between}\\ \text{CASE A\&B}\end{array} + \begin{array}{l}\text{Startup costs}\\ \text{difference}\\ \text{between}\\ \text{CASE A\&B}\end{array} + \begin{array}{l}\text{Cost difference}\\ \text{due to part load}\\ \text{operation of hydro}\\ \text{between CASE}\\ \text{A\&B}\end{array}$$

Calculation is based on dispatches in daytime column in the table 13 and 14 in APPENDIX G.

$$\begin{array}{c}\text{Thermal}\\ \text{cost difference}\end{array} = \sum_{i=1}^{i=n} \left(\begin{array}{c}\text{Additional energy}\\ \text{from i}^{\text{th}}\text{ thermal generator}\\ \text{in CASE B (MWh)}\end{array} \times \begin{array}{c}\text{Unit cost of the i}^{\text{th}}\\ \text{thermal generator}\\ \text{(Rs/MWh)}\end{array} \right)$$

n = number of thermal generators connected

According to tables 13 and 14 in APPENDIX G, additional five Sapugaskanda B generators of total 44MW have been dispatched for additional spinning reserve

$$\begin{array}{c}\text{Thermal}\\ \text{cost difference}\end{array} = \text{Energy from Sapugaskanda B} \times \text{unit cost}$$

$$\begin{array}{c}\text{Thermal}\\ \text{cost difference}\end{array} = 44\text{MW} \times 9\text{ hours} \times 21{,}410\text{ Rs/MWh}$$

$$\begin{array}{c}\text{Thermal}\\ \text{cost difference}\end{array} = \underline{\underline{\text{Rs. }8{,}478{,}360}}$$

$$\begin{array}{c}\text{Hydro}\\ \text{cost difference}\end{array} = \sum_{i=1}^{i=n} \left(\begin{array}{c}\text{Additional energy}\\ \text{from i}^{\text{th}}\text{ hydro generator}\\ \text{in CASE B (MWh)}\end{array} \times \begin{array}{c}\text{Unit cost of the i}^{\text{th}}\\ \text{hydro generator}\\ \text{(Rs/MWh)}\end{array} \right)$$

n = number of hydro generators connected

According to tables 13 and 14 in APPENDIX G, an additional energy was obtained from Wimalasurendra and Canyon power station while reducing the energy from Victoria and Kotmale power station to maintain the additional spinning reserve.

$$\begin{matrix}\text{Hydro cost}\\ \text{difference}\end{matrix} = \begin{matrix}\text{Additional}\\ \text{energy}\\ \text{from}\\ \text{Wimalasurendra}\end{matrix} \times \begin{matrix}\text{Unit}\\ \text{cost}\\ \text{(Wimalasurendra)}\end{matrix} + \begin{matrix}\text{Additional}\\ \text{energy}\\ \text{from}\\ \text{Canyon}\end{matrix} \times \begin{matrix}\text{Unit}\\ \text{cost}\\ \text{(Canyon)}\end{matrix}$$

$$- \begin{matrix}\text{Reduced}\\ \text{energy}\\ \text{from}\\ \text{Victoria}\end{matrix} \times \begin{matrix}\text{Unit}\\ \text{cost}\\ \text{(Victoria)}\end{matrix} - \begin{matrix}\text{Reduced}\\ \text{energy}\\ \text{from}\\ \text{Kotmale}\end{matrix} \times \begin{matrix}\text{Unit}\\ \text{cost}\\ \text{(Kotmale)}\end{matrix}$$

The opportunity cost of hydro plants were used as the unit cost.

$$\begin{aligned}\begin{matrix}\text{Hydro cost}\\ \text{difference}\end{matrix} &= 25\text{MW}\times 9\text{ hours}\times 18916.2\text{Rs/MWh} + 25\text{MW}\times 9\text{ hours}\times 17{,}178.1\text{Rs/MWh}\\ &\quad - 34\text{MW}\times 9\text{hours}\times 6{,}887.7\text{Rs/MWh}\\ &\quad - 60\text{MW}\times 9\text{hours}\times 18916.2\text{Rs/MWh}\end{aligned}$$

$$\begin{matrix}\text{Hydro cost}\\ \text{difference}\end{matrix} = \underline{\underline{\text{Rs. -4,201,162.2}}}$$

$$\begin{matrix}\text{Startup}\\ \text{cost difference}\end{matrix} = \sum_{i=1}^{i=n} \begin{matrix}\text{Startup cost of the}\\ \text{i}^{\text{th}}\text{ thermal generator}\\ \text{in case B}\end{matrix} + \sum_{i=1}^{i=n} \begin{matrix}\text{Startup cost of the}\\ \text{i}^{\text{th}}\text{ thermal generator}\\ \text{in case A}\end{matrix}$$

n = number of thermal generators connected

According to tables 13 and 14 in APPENDIX G, five Sapugaskanda B generators have been dispatched to maintain additional spinning reserve

$$\begin{matrix}\text{Startup}\\ \text{cost difference}\end{matrix} = \text{Rs.}23000\times 5 = \underline{\underline{\text{Rs. 115,000}}}$$

$$\begin{matrix}\text{Cost difference due to}\\ \text{part load operation}\\ \text{of hydro}\end{matrix} = \sum_{i=1}^{i=n} \left(\begin{matrix}\text{Difference of the}\\ \text{energy loss due to part}\\ \text{load operation of}\\ \text{i}^{\text{th}}\text{ hydro generator}\\ \text{between}\\ \text{case A \& B (MWh)}\end{matrix} \times \begin{matrix}\text{Unit cost of the i}^{\text{th}}\\ \text{hydro generator}\\ \text{(Rs/MWh)}\end{matrix} \right)$$

n = number of hydro generators connected

Water discharge rates (m^3s^{-1}) for part load operation were obtained from discharge-active power curves (See figure 1). The million cubic meters (MCM) per megawatt hour of generation (MWh) values of the corresponding hydro machines were calculated using water discharge rates as shown in table 17.

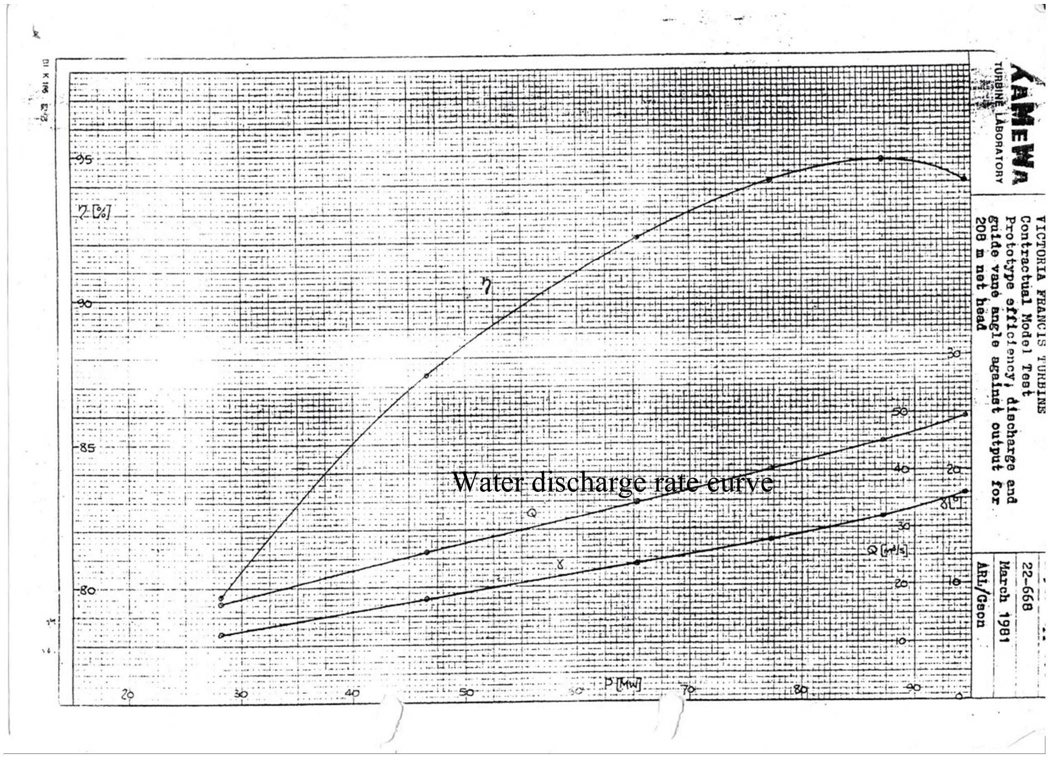


Figure 1: An Active power vs Discharge rate curve of a Victoria generator

Table 17: Calculated water discharge in MCM/MWh at step loading for a Victoria generator

Machine load (MW)	**Water discharge (MCM/MWh)**	**Additional discharge w.r.t full machine load**
20	0.00258	17%
25	0.00258	17%
30	0.00246	12%
35	0.00238	8%
40	0.00231	5%
45	0.00226	3%
50	0.00225	3%
55	0.00223	1%
60	0.00220	0%
65	0.00220	0%
70	0.00220	0%

Using these MCM/MWh values, the total additional discharge of water due to part load operation can be calculated. The energy lost from the additional discharge of water if a generator operated at its nominal power was calculated. The opportunity cost of hydro plants were used as the unit cost.

$$\begin{array}{c}\text{Cost difference due to}\\\text{part load operation}\\\text{of hydro}\end{array} = \begin{array}{c}\text{Energy that}\\\text{can be}\\\text{generated from}\\\text{additional water}\\\text{discharge from}\\\text{Victoria}\end{array} \times \begin{array}{c}\text{Unit cost}\\\text{(Victoria)}\end{array}$$

$$+ \begin{array}{c}\text{Energy that}\\\text{can be}\\\text{generated from}\\\text{additional water}\\\text{discharge from}\\\text{Kotmale}\end{array} \times \begin{array}{c}\text{Unit cost}\\\text{(Kotmale)}\end{array}$$

$$\begin{array}{c}\text{Cost difference due to}\\\text{part load operation}\\\text{of hydro}\end{array} = 69.573\text{MWh} \times 6887.7\text{Rs/MWh} + 23.498\text{MWh} \times 18916.2\text{Rs/MWh}$$

$$\begin{array}{c}\text{Cost difference due to}\\ \text{part load operation}\\ \text{of hydro}\end{array} = \underline{\underline{\text{Rs. }923{,}689}}$$

Table 18: Summary of calculations of the cost of additional spinning reserve for the daytime of the hydro-dominant day

	Day time
Thermal cost difference between CASE A & B (Rs.)	8,478,360
Hydro cost difference between CASE A & B (Rs.)	-4,201,162
Startup costs difference between CASE A & B (Rs.)	115,000
Cost difference due to part load operation of hydro between CASE A&B (Rs.)	923,689
Cost of additional spinning reserve (Rs.)	5,315,887

Similarly, calculations were performed for off peak, morning time and night time for the hydro-dominant day. Similar calculations were performed for the thermal-dominant day as well.

The calculation results are shown in the table 7-2.

APPENDIX I

Operating cost calculations for a day for the spinning reserve cost comparison

$$\text{Energy cost(Rs)}=\text{Active power(MW)}\times\text{no of hours(h)}\times\begin{matrix}\text{unit cost(Rs/kWh)}\\ \text{or}\\ \text{Opportunity cost(Rs/kWh}\end{matrix}$$

Table 19: Operating cost of thermal generators for the hydro dominant day for the spinning reserve cost comparison

Thermal operating cost for the hydro dominant day															
	Offpeak			**Morning time**			**Day time**			**Night time**					
Power station	**Active power (MW)**	**no of hours**	**Energy cost (Rs)**	**Active power (MW)**	**no of hours**	**Energy cost (Rs)**	**Active power (MW)**	**no of hours**	**Energy cost (Rs)**	**Active power (MW)**	**no of hours**	**Energy cost (Rs)**	**unit cost Rs/kWh**	**Startup cost Rs**	
Lakvijaya	200	6.5	**8,762,000**	200	4.0	**5,392,000**	270	9.0	**16,378,200**	270	4.5	**8,189,100**	6.74	**0**	
	200	6.5	**8,931,000**	200	4.0	**5,496,000**	270	9.0	**16,694,100**	270	4.5	**8,347,050**	6.87	**0**	
	200	6.5	**9,659,000**	200	4.0	**5,944,000**	270	9.0	**18,054,900**	270	4.5	**9,027,450**	7.43	**0**	
Sapugaskanda	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	9	4.5	**867,105**	21.41	**23,000**	
	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	9	4.5	**867,105**	21.41	**23,000**	
	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	9	4.5	**867,105**	21.41	**23,000**	
	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	9	4.5	**867,105**	21.41	**23,000**	
	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	7	4.5	**674,415**	21.41	**23,000**	
	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	7	4.5	**674,415**	21.41	**23,000**	
	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	7	4.5	**674,415**	21.41	**23,000**	
	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	7	4.5	**674,415**	21.41	**23,000**	
Barge	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	30	4.5	**2,917,350**	21.61	**249,026**	
TOTAL THERMAL OPERATING COST (Rs)			**27,352,000**			**16,832,000**			**51,127,200**			**34,647,030**		**433,026**	**130,391,256**

Table 20: Operating cost of hydro generators for the hydro dominant day for the spinning reserve cost comparison

Hydro cost for the hydro dominant day														
	Offpeak			Morning time			Day time			Night time				
Power station	Active power (MW)	no of hours	Energy cost (Rs)	Active power (MW)	no of hours	Energy cost (Rs)	Active power (MW)	no of hours	Energy cost (Rs)	Active power (MW)	no of hours	Energy cost (Rs)	Opportunity cost Rs/kWh	
Wimalasurendra	25	6.5	**3,073,883**	20	4.0	**1,513,296**	25	9.0	**4,256,145**	15	4.5	**1,276,844**	18.92	
	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	15	4.5	**1,276,844**	18.92	
Canyon	20	6.5	**2,233,156**	20	4.0	**1,374,250**	25	9.0	**3,865,077**	15	4.5	**1,159,523**	17.18	
	20	6.5	**2,233,156**	0	4.0	**0**	0	9.0	**0**	15	4.5	**1,159,523**	17.18	
Old Laxapana	9	6.5	**489,319**	9	4.0	**301,119**	9	9.0	**677,518**	9	4.5	**338,759**	8.36	
	9	6.5	**489,319**	9	4.0	**301,119**	9	9.0	**677,518**	9	4.5	**338,759**	8.36	
	9	6.5	**489,319**	9	4.0	**301,119**	9	9.0	**677,518**	9	4.5	**338,759**	8.36	
	12	6.5	**652,425**	12	4.0	**401,492**	12	9.0	**903,357**	12	4.5	**451,679**	8.36	
	12	6.5	**652,425**	12	4.0	**401,492**	12	9.0	**903,357**	12	4.5	**451,679**	8.36	
New Laxapana	50	6.5	**1,302,912**	50	4.0	**801,792**	50	9.0	**1,804,032**	50	4.5	**902,016**	4.01	
	57	6.5	**1,485,320**	57	4.0	**914,043**	57	9.0	**2,056,596**	57	4.5	**1,028,298**	4.01	
Polpitiya	40	6.5	**721,048**	40	4.0	**443,722**	40	9.0	**998,374**	43	4.5	**536,626**	2.77	
	40	6.5	**721,048**	40	4.0	**443,722**	40	9.0	**998,374**	43	4.5	**536,626**	2.77	
Samanalawewa	40	6.5	**4,844,736**	40	4.0	**2,981,376**	40	9.0	**6,708,096**	40	4.5	**3,354,048**	18.63	
	40	6.5	**4,844,736**	40	4.0	**2,981,376**	40	9.0	**6,708,096**	40	4.5	**3,354,048**	18.63	
Kukule ganga	0	6.5	**0**	0	4.0	**0**	37	9.0	**4,214,921**	37	4.5	**2,107,460**	12.66	
	0	6.5	**0**	0	4.0	**0**	37	9.0	**4,214,921**	37	4.5	**2,107,460**	12.66	
Upper Kothmale	0	6.5	**0**	75	4.0	**2,257,794**	75	9.0	**5,080,037**	75	4.5	**2,540,018**	7.53	
	0	6.5	**0**	75	4.0	**2,257,794**	75	9.0	**5,080,037**	75	4.5	**2,540,018**	7.53	
Kothmale	0	6.5	**0**	0	4.0	**0**	67	9.0	**11,406,469**	67	4.5	**5,703,234**	18.92	
	0	6.5	**0**	0	4.0	**0**	67	9.0	**11,406,469**	67	4.5	**5,703,234**	18.92	
	0	6.5	**0**	30	4.0	**2,269,944**	67	9.0	**11,406,469**	67	4.5	**5,703,234**	18.92	
Victoria	54	6.5	**2,417,583**	69	4.0	**1,901,005**	44	9.0	**2,727,529**	54	4.5	**1,673,711**	6.89	
	70	6.5	**3,133,904**	70	4.0	**1,928,556**	50	9.0	**3,099,465**	70	4.5	**2,169,626**	6.89	
	0	6.5	**0**	70	4.0	**1,928,556**	0	9.0	**0**	60	4.5	**1,859,679**	6.89	
Randenigala	60	6.5	**5,921,019**	60	4.0	**3,643,704**	60	9.0	**8,198,334**	60	4.5	**4,099,167**	15.18	
	60	6.5	**5,921,019**	60	4.0	**3,643,704**	60	9.0	**8,198,334**	60	4.5	**4,099,167**	15.18	
Rantambe	25	6.5	**3,080,318**	25	4.0	**1,895,580**	20	9.0	**3,412,044**	25	4.5	**2,132,528**	18.96	
	25	6.5	**3,080,318**	25	4.0	**1,895,580**	20	9.0	**3,412,044**	25	4.5	**2,132,528**	18.96	
Ukuwela	18	6.5	**2,160,545**	18	4.0	**1,329,566**	18	9.0	**2,991,524**	18	4.5	**1,495,762**	18.47	
	18	6.5	**2,160,545**	18	4.0	**1,329,566**	18	9.0	**2,991,524**	18	4.5	**1,495,762**	18.47	
Bowathenna	37	6.5	**7,139,820**	37	4.0	**4,393,735**	37	9.0	**9,885,904**	37	4.5	**4,942,952**	29.69	
TOTAL HYDRO OPERATING COST (Rs)			**59,247,868**			**43,835,003**			**128,960,082**			**69,009,571**		**301,052,523**

Table 21: Operating cost of thermal generators for the thermal dominant day for the spinning reserve cost comparison

Thermal operating cost for the thermal dominant day															
	Offpeak			**Morning time**			**Day time**			**Night time**					
Power station	**Active power (MW)**	**no of hours**	**Energy cost (Rs)**	**Active power (MW)**	**no of hours**	**Energy cost (Rs)**	**Active power (MW)**	**no of hours**	**Energy cost (Rs)**	**Active power (MW)**	**no of hours**	**Energy cost (Rs)**	**unit cost Rs/kWh**	**Startup cost Rs**	
Kelanithissa GT 7	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	72	4.5	**12,221,280**	37.72	**1,321,688**	
Kelanithissa CCP	90	6.5	**11,477,700**	90	4.0	**7,063,200**	100	9.0	**17,658,000**	90	4.5	**7,946,100**	19.62	**0**	
	60	6.5	**0**	60	4.0	**0**	60	9.0	**0**	60	4.5	**0**		**0**	
Lakvijaya	270	6.5	**11,828,700**	270	4.0	**7,279,200**	270	9.0	**16,378,200**	270	4.5	**8,189,100**	6.74	**0**	
	270	6.5	**12,056,850**	270	4.0	**7,419,600**	270	9.0	**16,694,100**	270	4.5	**8,347,050**	6.87	**0**	
	270	6.5	**13,039,650**	270	4.0	**8,024,400**	270	9.0	**18,054,900**	270	4.5	**9,027,450**	7.43	**0**	
Sapugaskanda A	11	6.5	**1,697,410**	0	4.0	**0**	16	9.0	**3,418,560**	16	4.5	**1,709,280**	23.74	**52,000**	
	0	6.5	**0**	0	4.0	**0**	16	9.0	**3,418,560**	16	4.5	**1,709,280**	23.74	**52,000**	
	0	6.5	**0**	0	4.0	**0**	16	9.0	**3,418,560**	16	4.5	**1,709,280**	23.74	**52,000**	
	0	6.5	**0**	0	4.0	**0**	16	9.0	**3,418,560**	16	4.5	**1,709,280**	23.74	**52,000**	
Sapugaskanda B	9	6.5	**1,252,485**	9	4.0	**770,760**	9	9.0	**1,734,210**	9	4.5	**867,105**	21.41	**0**	
	9	6.5	**1,252,485**	9	4.0	**770,760**	9	9.0	**1,734,210**	9	4.5	**867,105**	21.41	**0**	
	9	6.5	**1,252,485**	9	4.0	**770,760**	9	9.0	**1,734,210**	9	4.5	**867,105**	21.41	**0**	
	9	6.5	**1,252,485**	9	4.0	**770,760**	9	9.0	**1,734,210**	9	4.5	**867,105**	21.41	**0**	
	9	6.5	**1,252,485**	9	4.0	**770,760**	9	9.0	**1,734,210**	9	4.5	**867,105**	21.41	**0**	
	9	6.5	**1,252,485**	9	4.0	**770,760**	9	9.0	**1,734,210**	9	4.5	**867,105**	21.41	**0**	
	9	6.5	**1,252,485**	9	4.0	**770,760**	9	9.0	**1,734,210**	9	4.5	**867,105**	21.41	**0**	
	9	6.5	**1,252,485**	9	4.0	**770,760**	9	9.0	**1,734,210**	9	4.5	**867,105**	21.41	**0**	
Uthurujanani	0	6.5	**0**	0	4.0	**0**	24	9.0	**5,153,760**	24	4.5	**2,576,880**	23.86	**0**	
Barge	60	6.5	**8,427,900**	60	4.0	**5,186,400**	60	9.0	**11,669,400**	60	4.5	**5,834,700**	21.61	**0**	
ACE Matara	0	6.5	**0**	0	4.0	**0**	24	9.0	**5,581,440**	24	4.5	**2,790,720**	25.84	**231,112**	
Diesel	0	6.5	**0**	0	4.0	**0**	70	9.0	**16,506,000**	100	4.5	**11,790,000**	26.2	**0**	
Asia Power	0	6.5	**0**	0	4.0	**0**	48	9.0	**11,188,800**	48	4.5	**5,594,400**	25.9	**919,056**	
Sojitz CCP	163	6.5	**23,542,090**	163	4.0	**14,487,440**	163	9.0	**32,596,740**	163	4.5	**16,298,370**	22.22	**0**	
ACE Embilipitiya	0	6.5	**0**	0	4.0	**0**	93	9.0	**21,669,930**	93	4.5	**10,834,965**	25.89	**873,951**	
WCP	0	6.5	**0**	270	4.0	**24,084,000**	270	9.0	**54,189,000**	270	4.5	**27,094,500**	22.3	**3,255,459**	
CEB Supplementary power	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	50	4.5	**6,509,250**	28.93	**0**	
TOTAL THERMAL OPERATING COST (Rs)			**92,090,180**			**79,710,320**			**254,888,190**			**148,828,725**		**6,809,266**	**582,326,681**

Table 22: Operating cost of hydro generators for the thermal dominant day for the spinning reserve cost comparison

Hydro cost for the thermal dominant day														
	Offpeak			**Morning time**			**Day time**			**Night time**				
Power station	**Active power (MW)**	**no of hours**	**Energy cost (Rs)**	**Active power (MW)**	**no of hours**	**Energy cost (Rs)**	**Active power (MW)**	**no of hours**	**Energy cost (Rs)**	**Active power (MW)**	**no of hours**	**Energy cost (Rs)**	**Opportunity cost Rs/kWh**	
Old Laxapana	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	0	4.5	**0**	29.76	
	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	0	4.5	**0**	29.76	
	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	0	4.5	**0**	29.76	
	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	0	4.5	**0**	29.76	
	10	6.5	**1,934,595**	0	4.0	**0**	10	9.0	**2,678,670**	10	4.5	**1,339,335**	29.76	
New Laxapana	25	6.5	**4,719,195**	10	4.0	**1,161,648**	0	9.0	**0**	0	4.5	**0**	29.04	
	0	6.5	**0**	0	4.0	**0**	12	9.0	**3,136,450**	10	4.5	**1,306,854**	29.04	
Polpitiya	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	0	4.5	**0**	28.40	
	10	6.5	**1,846,026**	10	4.0	**1,136,016**	20	9.0	**5,112,072**	10	4.5	**1,278,018**	28.40	
Victoria	49	6.5	**9,249,622**	55	4.0	**6,389,064**	40	9.0	**10,454,832**	50	4.5	**6,534,270**	29.04	
	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	60	4.5	**7,841,124**	29.04	
	0	6.5	**0**	0	4.0	**0**	0	9.0	**0**	0	4.5	**0**	29.04	
TOTAL HYDRO OPERATING COST (Rs)			**17,749,438**			**8,686,728**			**21,382,024**			**18,299,601**		**66,117,791**