TECHNO-ECONOMIC FEASIBILITY OF 400kV FOR THE 2032 TRANSMISSION SYSTEM OF SRI LANKA

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Degree of Master of Science

Department of Electrical Engineering

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DECLARATION OF THE CANDIDATE & SUPERVISORS

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ABSTRACT

Electricity is a basic need for the economic growth of any country. Therefore, the electricity demand grows at a higher rate with the rapid development of the economy. To meet the increasing demand of electricity, addition of new generation capacity into the system is required.However, with new generation additions , there should be a way to transmit bulk power to load centers. This transfer of power is done through the transmission network.

Transmission system of Sri Lanka mainly operatesat 220 kV and 132 kV voltage levels and it interconnects the grid substations (GS) and power stations (PS). Together with the increase of electricity demand and bulk power generation, there is a point at which introduction of new higher voltage level is required for reliable, efficient and better quality of supply. However, it has to be technically feasible and economically justifiable.

This study focuses on the major bulk power transmission from Sampur, Ambalangoda and Hambanthota generation stations of Sri Lanka to load centers. Two power system models for each 220kV and 400kV voltage level options were developed for the years 2025 and 2032. These models were analyzed for voltage stability using PV and QV curves in order to find the technical feasibility between the two options.

Then the economic analysis between the two options was performed in order to assess the economic feasibility of the two options.Technical feasibility and economic justification of introducing a higher voltage than that of existing voltage to transmit bulk power to load centers from bulk power generating stations in Sri Lanka is discussed in detail in this research.

Keywords: *economical, electricity, transmission, voltage stability*

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LIST OF ABBREVIATIONS

Abbreviation	Description
AC	Alternating Current
ACSR	Aluminium Conductor Steel Reinforced
B/C	Benefit to Cost ratio
CEB	Ceylon Electricity Board
DC	Direct Current
EHV	Extra-High Voltage
EIRR	Economic Internal Rate of Return
FC	Foreign Cost
GE	General Electric
GS	Grid Substation
GS/PS	Grid Substation and Power Station
HV	High Voltage
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
LC	Local Cost
LTGEP	Long Term Generation Expansion Plan
LV	Low Voltage
MF	Multiplying Factor
MLKR	Rupees Million
MV	Medium Voltage
NPV	Net Present Value
PS	Power Station
PSS®E	Power System Simulator for Engineering
ROW	Right of Way
SCC	Short Circuit Capacity
SIL	Surge Impedance Loading
SS	Switching Station
TL	Transmission Line
UG	Under-Ground
UHV	Ultra-High Voltage

LIST OF APPENDICES

1. INTRODUCTION

1.1. Sri Lankan Power System

In 2014 Sri Lankapower system had a total installed capacity of about 3932 MW and a maximum load of around 2164 MW. Ceylon Electricity Board (CEB) is responsible for the generation, transmission and distribution of electricity in Sri Lanka as the only power transmission utility.

Transmission system mainly comprises of substations, transmission lines, associated control and protection schemes and auxiliaries etc. Typical transmission system interconnects generation stations to distribution network delivering bulk power to the load centers as shows in the Figure 1.1

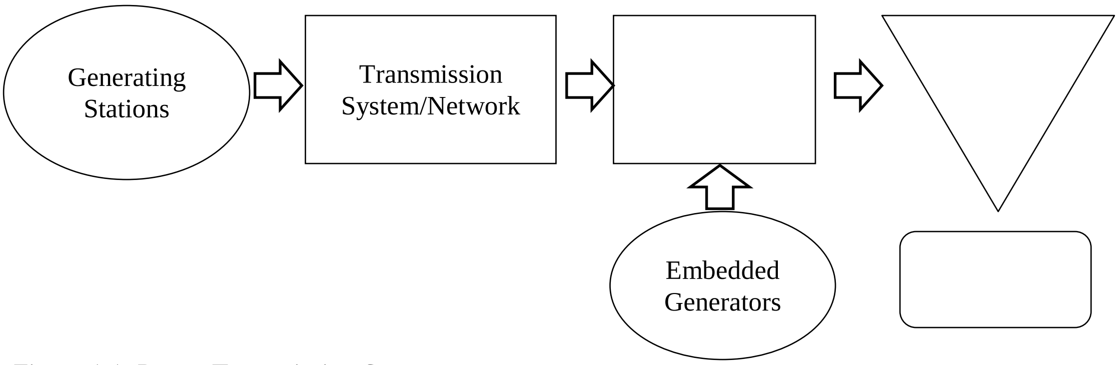

Figure 1.1: Power Transmission Stages

The generation voltages used in Sri Lanka are usually in the range of 11kV to 13.8kV (in the MV range). To reduce the energy losses and reduce the costs involved, these low voltages are stepped up by using step up transformer to higher voltages up to 132kV, 220kV and transmitted to bulk power grid substations where it is stepped down to 33 kV and 11kV and distribute with 400V and 230V to the consumer loads.

At present 220 kV is the highest voltage level used in the Sri Lanka power system and Figure 1.2 shows the Map of the 2015 Transmission Network.

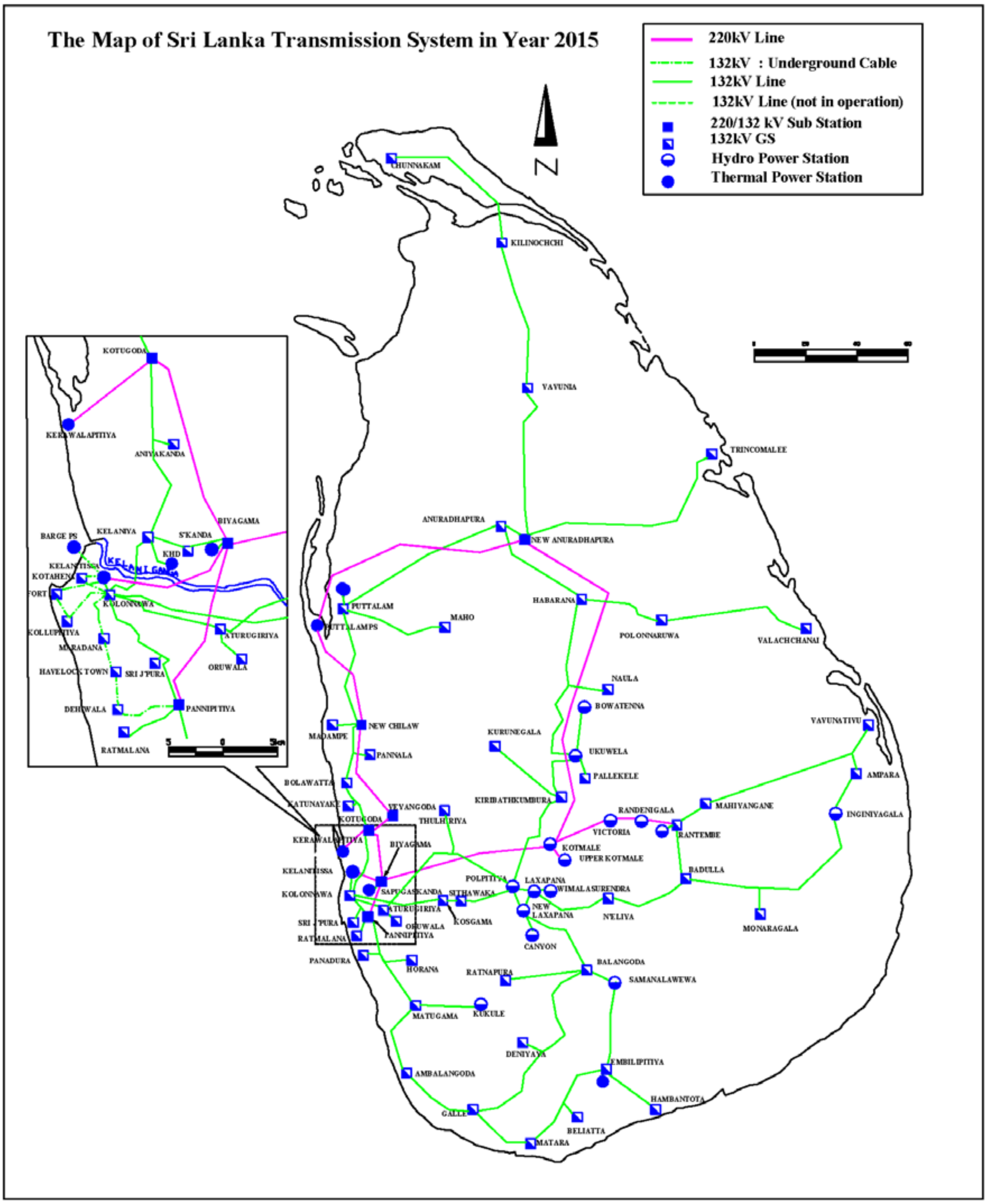

Figure 1.2: 2015 Transmission Network of Sri Lanka

Source: (Long Term Transmission Development Plan 2013-2022)

Present Transmission Network of Sri Lanka comprises of:

- 220 kV high voltage transmissionlinenetwork
- 132 kVbackbonetransmission line network
- 220/132/33kVGrid substations
- 132/33kVGridsubstations
- 132/11kV Grid substations
- 33kVlevelreactivepower compensation

1.2. Motivation

Transmission planning involves making decisions to augment the transmission network with new voltage levels to provide an uninterrupted, reliable, efficient and quality power supply to the consumers at all times. In taking these decisions, there are several challenges faced by the utility, which includes; prediction of load growth, limitation of feasible potential power generation sites and difficulties in getting right of way (ROW) for new transmission lines that connects with the new generation stations and load centers.

There is a rapid economic growth in Sri Lanka after ending the 30 year civil war. Electricity being a main driving force behind the growing economy, equally rapid increase in the electricity demand is predicted [Figure 1.3].

The utility is responsible for supplying the growing electricity demand, which would require addition of bulk power generation. However, Sri Lanka is highly vulnerable to the above discussed challenges in transmission network augmentation. Being a small island with high population, potential power generation sites are limited in number. Also, getting the right of way for new transmission lines interconnecting the proposing bulk power generation sites with load centers is also a challenging fact. Under these challenges, utility has to decide whether it is the right time to introduce new higher voltage level to the transmission system to avoid any transmission capacity constraint and provide reliable, quality power supply to the consumers.

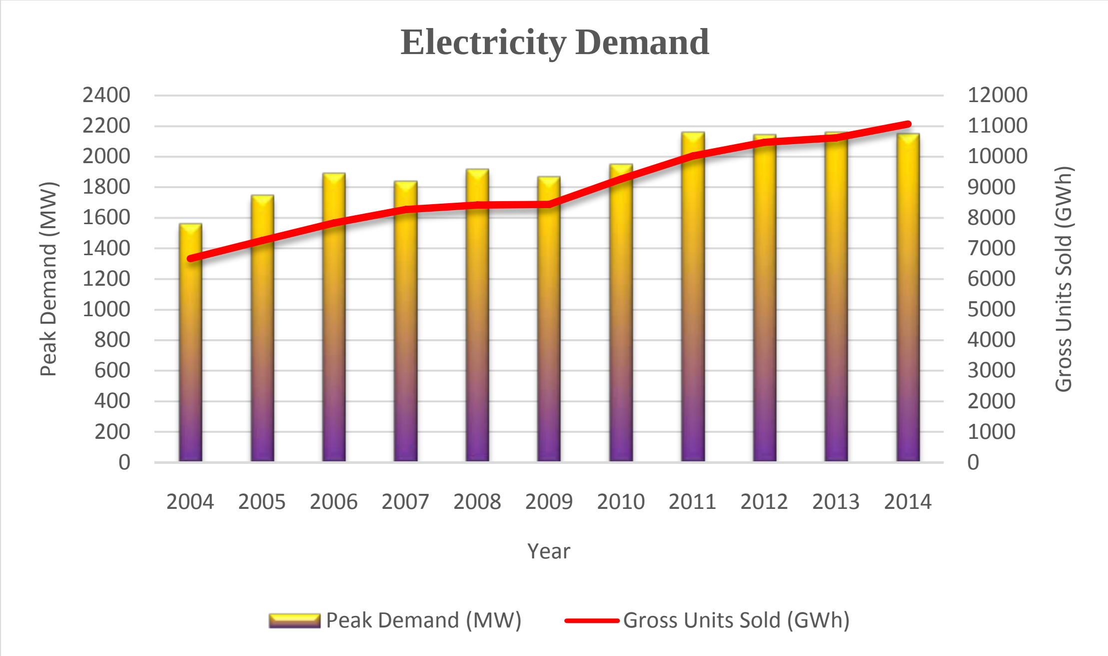

Figure 1.3: Electricity Demand Trend

Source: (CEB Statistical Digests from 2004 to 2014)

There is major power generation expansions proposed, which includes bulk power plant additions in two most probable sites i.e. north east and southern coast, in the Long Term Generation Expansion Plan 2013-2032 of CEB. With these major changes to the network, it is important to decide whether it requires an upgrade to the transmission voltage level.Therefore, it is important to analyze and evaluate the economic and technical feasibility in upgrading the transmission voltage level in Sri Lanka.

This study investigates the economic and technical feasibility of introducing 400kV transmission voltage against the present 220kV transmission voltage for the year 2032 transmission network of Sri Lanka. This study is mainly focused on the voltage stability of the Sri Lankan power system. The outcome of this study will be the choice of the most economically and technically feasible transmission voltage to be used up to the year 2032. It will help the utility and the government to take a decision whether to invest on a new transmission voltage or to delay that investment and use it for some other high priority project.

1.3. Objectives

The main objective of this study is to determine the economic and technical feasibility of introducing 400kV against the 220kVvoltagefor the transmission network of Sri Lanka in the coming 16 year plan.

1.4. Research approach

The topic being investigated in the research project is “Techno-Economic Feasibility of 400kV for the2032 Transmission Network of Sri Lanka”. The outcome will be a choice of voltage between 220 kV and 400 kV for the future transmission interconnection of bulk power transmission lines in Sri Lanka power system. The study will be focused on the major bulk power transmission from Sampur, Ambalangoda and Hambanthota generation stations to the load centers.

First data collection related for 400 kV was carried out. Then the two different system configurations were designed based on the two system voltages, 220 kV versus 400 kV for years 2025 and 2032. Then, power system models for each configuration were developed in PSS®E (Power System Simulator for Engineering) software. Next, theoretical justification was developed for the prescribed two power system models. Then, voltage stability studies were performed (PV, QV analysis) to find out the technical feasibility of the two system configurations. Finally, the economic analysis between the two system configurations was performed to evaluate the economic feasibility of the two options.

In this research project, the widely known power system simulation software package PSS®E was used. PSS®E is a versatile, commercialized power systems analysis tool that can be used for several simulation studies including, steady state voltage stability checks such as PV and QV analysis, steady state system analysis (power flow) and transient stability analysis (rotor angle stability).

1.5. Dissertation outline

This dissertation reflects the research approach discussed above. Literature review is presented in chapter 2, describing the theories involved and the previous research done in this area. In chapter 3, the system configurations and the modelling approach is discussed. Static voltage analysis for the system configurations is described in chapter 3 and itis discussed in chapter 4. Chapter 5presents the detailed economic analysis between the two possible network topologies. In chapter 6, the conclusions of the research project are summarized and topics for further research are indicated.

Chapter 2

2. LITERATURE REVIEW

2.1. Transmission Voltage

A power system is comprised of generation stations, transmission network, distribution network and the load centers. The main tasks of a power system involve,

- Supply required power to all the consumers at different geographical locations at all times continuously.
- Maintain maximum security of supply and minimum fault duration.
- Supply electrical power within the statutory limits of frequency and voltage.
- Supply energy at a least cost.
- Supply energy with sufficient power quality.

Transmission network plays a major role in attaining the above mentioned tasks. The main purpose of the transmission system is to deliver the bulk power from one location to another location or from one network to another network depending on its locality.

According to EN 60071 standards [2], power system voltage can be classified as follows,

1. Below 1 kV: Low Voltage (LV)
2. Between 1 kV and 45 kV: Medium Voltage (MV)
3. Between 45 kV and 300 kV: High Voltage (HV)
4. Between 300 kV and 750 kV: Extra-High Voltage (EHV)
5. Above 800 kV: Ultra-High Voltage (UHV)

Difficulty of locating power station sites near the consuming centers makes it inevitable to transfer bulk of electrical energy through longer distances and is possible only by high voltage transmission systems. High voltage is desired for transmission due to the following reasons,

- It reduces the power loss,which is inversely proportional to square of system voltage due to the reduction in current.
- Allows higher power transmission capability for the same conductor.
- With the reduction of the voltage drop along the line it enhances the efficiency of transmission and the voltage regulation along the line.

The various voltages adopted by different countries above 220kV are 275 kV, 287 kV, 345 kV, 380 kV, 400 kV, 500 kV, 735 kV, 1100kV etc. There are two main problems involved in limiting the large amount of power to be transmitted over long distances by AC systems. The first is the technical limitation and other is the economic consideration and usually later governs the final choice of the design.

The capital cost of the transmission line is highly influenced by the system voltage level in EHV system. The weight of conductor material, the efficiency of the line, the voltage drop in the line and system stability depends upon system voltage. Therefore, the choice of voltage level is a major factor in the transmission line designs.

The choice of transmission voltage mainly depends on,

1. Distance of transmission line
2. Power to be transmitted
3. Existing standard voltages
4. Available technologies (HVAC,HVDC,etc.)

2.1.1. Use of empirical formulas to select the transmission voltage level

From the above factors several empirical formulas had been derived in order to find the economical transmission voltage for a new transmission line. The following equation 2.1 [3] depicts one of the several empirical formulas which are used to select the economical voltage.

$$V_L = 5.5 \times \sqrt[2]{\left(\left(\frac{L}{1.6}\right) + \left(\frac{P \times 1000}{\cos\phi \times N_C \times 150}\right)\right)} \quad (2.1)$$

Where,

L – Line length in km

P – Power per phase

Cosϕ– Power factor

Nc– Number of circuits

2.1.2. Use of surge impedance loading to select the transmission voltage level

A transmission line may be considered as generating capacitive reactive power in its shunt capacitance and consuming inductive reactive power in its series inductance. The load at which the inductive and capacitive reactive powers are equal and opposite is called surge impedance loading (SIL). The impedance, this phenomenon occurs is also called surge impedance (Z_0). Equation 2.2 [4] shows the relationship between capacitance, inductance and the surge impedance.

$$\frac{V^2}{X_C} = I^2 \times X_L => \frac{V}{I} = \sqrt{\left(\frac{L}{C}\right)} = Z_0 \quad (2.2)$$

Where,

V – Voltage

I – Current

$\boldsymbol{X_c}$ – Capacitive reactance

$\boldsymbol{Z_0}$ – Surge impedance

L – Line inductance

C – Line capacitance

$\boldsymbol{X_L}$ – Inductive reactance

Surge impedance loading (SIL) of any transmission line is defined as the power delivered by itself to a purely resistive load which is equal to its surge impedance. Equation 2.3 shows the relationship between SIL, $Z_0$and the transmission line voltage.

$$SIL = \frac{V_L^2}{Z_0} \quad (2.3)$$

Where,

$\boldsymbol{V_L}$ - Transmission line voltage in kV

$\boldsymbol{Z_0}$ - Surge impedance in Ω

Therefore SIL is an indication of the power transmitting capability, ***P(t)***.As given in Equation 2.4 [4] to determine ***P(t),*** SIL is multiplied by factor ***(MF)*** obtained from the standard capability curve shown in Figure 2.1.The transmission line loadability curve [5] is plotted between ***MF*** and line length (km).

$$P(t) = SIL \times MF \tag{2.4}$$

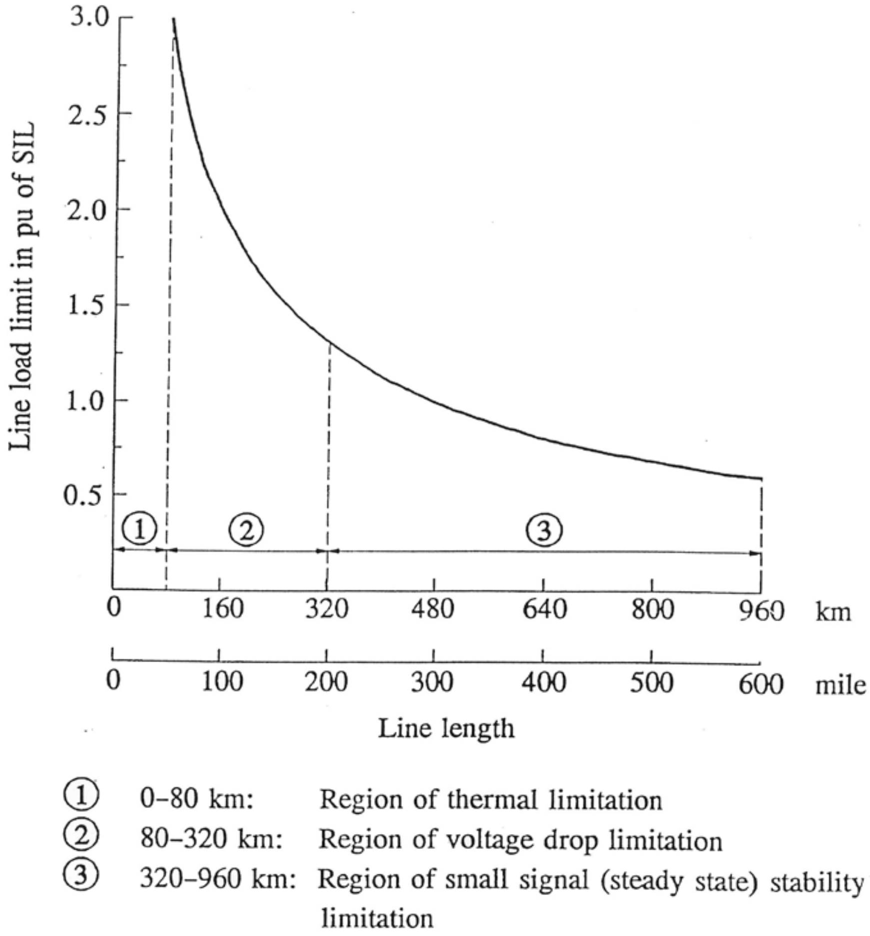

Figure 2.1: Transmission Line Loadability Curve

Source:(Power System Stability and Control by PrabhaKundur, page 229)

2.2. History of WorldPower Transmission

In 1878, Thomas A. Edison began work on the electric light and formulated the concept of a centrally located power station with distributed lighting serving a surrounding area. He perfected his light by October 1879, and the opening of his historic Pearl Street Station in New York City on September 4, 1882, marked the beginning of the electric utility industry. At Pearl Street, DC (Direct Current) generators, then called dynamos, were driven by steam engines to supply an initial load of 30 kW for 110-V incandescent lighting to 59 customers in a one-square-mile area. From this beginning in 1882 through 1972, the electric utility industry grew at a remarkable pace; a growth based on continuous reductions in the price of electricity due primarily to technological accomplishment and creative engineering. The introduction of the practical dc motor by Sprague Electric, as well as the growth of incandescent lighting, promoted the expansion of Edison's dc systems [6].

The development of three-wire 220V DC systems allowed load to increase somewhat, but as transmission distances and loads continued to increase, voltage problems were encountered. These limitations of maximum distance and load were overcome in 1885 by William Stanley's development of a commercially practical transformer. Stanley installed an AC (Alternating Current) distribution system in Great Barrington, Massachusetts, to supply 150 lamps. With the transformer, the ability to transmit power at high voltage with the corresponding lower current and lower line-voltage drops made AC more attractive than DC. The first single-phase AC line in the United States was operated in 1889 in Oregon, between Oregon City and Portland for 21 km at 4 kV[6]. First Electrical power transmission lines are tabulated in the Table 2.1

Table 2.1: First Electrical Power Lines

	AC/DC	Length (km)	Voltage (kV)	Date	Location
First Line	DC	59	2.4	1882	Germany
First single phase line	AC	21	4.0	1889	Oregon, USA
First three phase line	AC	179	12.0	1891	Germany

Source: (Power System Analysis & Design by Duncan Glover and Sharma 2012)

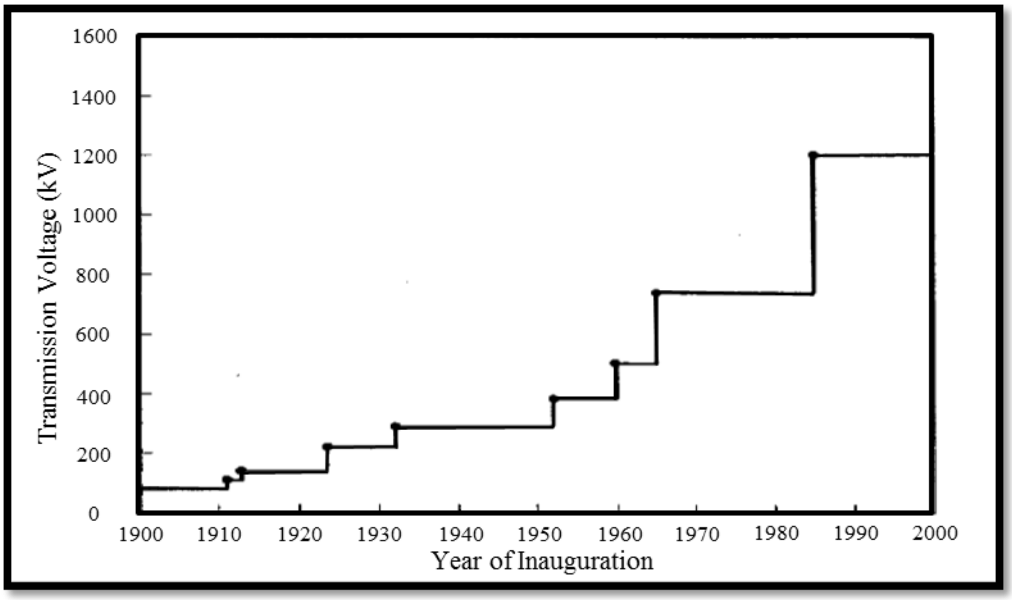

Figure 2.2: Development of transmission voltage of three phase AC networks

Source: (Overhead Power Lines, Planning,Design,Construction by F. Kiessling, P.Nefzger, J.F. Nolasco, U. Kaintzyk Page 6)

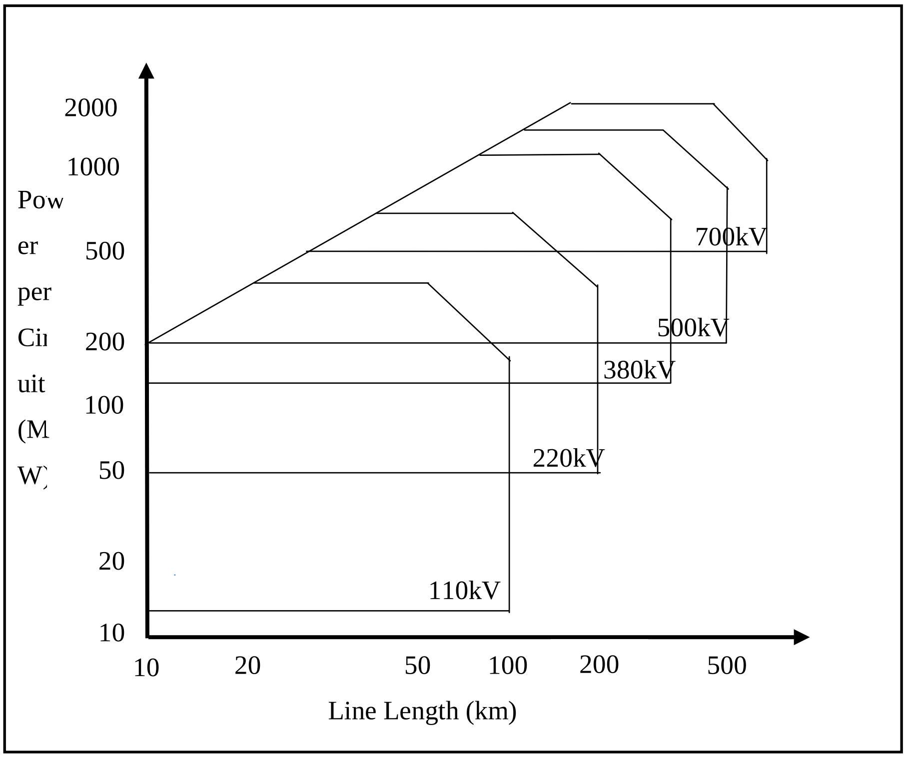

Figure 2.3: Voltage selection for transmission of electrical energy

Source: (Overhead Power Lines, Planning,Design,Construction by F. Kiessling, P.Nefzger, J.F. Nolasco, U. Kaintzyk Page 7)

Further Figure 2.2 [7] shows the development of transmission voltage of three phase AC networks over the period of 1900 to 2000 (in 20th century). Figure 2.3 [7] illustrates the selection of transmission voltage depending upon both the amount of energy/power transferred and the distance of power transmission.

2.3. Background on Sri Lankan power system

Ceylon Electricity Board, the state owned electricity utility established in 1969 is responsible for developing and maintaining an efficient, coordinated and economical system of Electricity Supply for the whole of Sri Lanka. At present Sri Lanka’s power system consists of CEB owned medium and large hydro power plants of 1377 MW and oil-fired thermal power plants of 1467 MW. In addition, oil-fired thermal power plants of 671MWcapacity connected to the national grid are operated by the Independent Power Producers.The first coal-fired power plant, Lakvijaya(900 MW) is presently in operation. Apart from the above, small power plants of 293 MW, (mainly mini hydro) owned and operated by the private sector are connected to the 33kV distribution network as embedded generators.There are about 120MW of wind power plants operational and connected to the grid that is owned and operated by private developers in the North-Western (100MW) and Northern (20MW) part of the country. CEB operates a 220kV/132kV transmission network with a total length of approximately 2860 km. Maximum demand so far met by the CEB is 2164MW with an annual generation 12357GWh [8].

2.3.1. History of Sri Lanka Power System and Transmission Voltage

In 1895 Colombo was supplied with diesel engines in the PettahPower Station (PS), when electricity was introduced to Sri Lanka. In 1929 the total demand was about 1.9 MW and the installed capacity at that time was 2.4 MW. With the Construction of Stanley PS at Kolonnawa in 1929 and augmentation at PettahPS in 1939 the total installed capacity was increased to 14.4 MW and the system peak was about 7.8 MW at that time [9].

Laxapana Power Station was the first hydro power station to be constructed which was declared open in 1950 that had an installed capacity of 25 MW. The installed capacity of this hydro power station was increased to 50 MW in 1958. In this time electricity was transmitted using 66kV voltage to the load center in Colombo. In 1958, the next hydro power station at Norton Bridge was done, which is named as the “Wimalasurendra Power Station” after the Eng. D.J. Wimalasurendra, owing to his vision to utilize the hydro power potential in Sri Lanka. This power station also added 50 MW to the National Grid. By this time other two small hydropower stations;Inginiyagala in 1954 (10 MW) and Uda Walawe (6 MW) in 1968were also connected to the National Grid; however power available from these two small stations were seasonal [10].

In 1964, Kelanitissa thermal power station was completed and added another 50 MW to the National Grid.

In 1969, Polpitiya (Samanala) PS with an installed capacity of 75 MW was constructed using the water resources from MaskeliOya. The New LaxapanaPS (100 MW) was completed in 1974. Canyon PS (30 MW) on the MaskeliyaOya was also completed in 1983. With these new developments in generation at Laxapana Complex, 132kV transmission voltage was introduced to the National grid of Sri Lanka.

The Chunnakam (diesel) station (8 MW) was installed in 1959. In order to meet the expected energy shortfall in the immediate future, thermal plants with a total capacity of 170 MW had been installed at Kelanitissa and an 80 MW plant had been installed at Sapugaskanda (1984).

The Polgolla,Bowatenne diversion was inaugurated in 1970. UkuwelaPS in 1976 andBowatennaPS in 1981 were commissionedtooperate using the water diversion at Polgolla,Bowatenna. The operation of these two plants highly depends on the irrigation releases.

Under the accelerated Mahaweli developmentprogramme in 1990s, Victoria PS (first stage 210 MW), KotmalePS (201 MW), RandenigalaPS (122 MW) and RantembePS (50 MW) were added to the National Grid. With this Mahaweli development project, 220kV transmission voltage was introduced to the Sri Lanka transmission network in order to transmit the bulk power generated by MahaweliComplex to the load centers. In 1980s to 1990s, most of the 66kV transmission lines were converted to 132kV for improve the transmission voltage profile of the Sri Lanka National Grid. Figure 2.4 depicts the transmission network in 1985 to 1989 where all 66kV, 132kV and 220kV (under construction) voltage levels are shown [11].

The 220kV transmission network was extended to New Anuradhapura, Kotugoda, Pannipitiya and later in 2011 to Puttalam with the introduction of First Coal Power Station having a total installed capacity of 900 MW at Norochcholai, Puttalam. Figure 1.2 shows the transmission network in year 2015 that includes both 132kV and 220kV voltage levels.

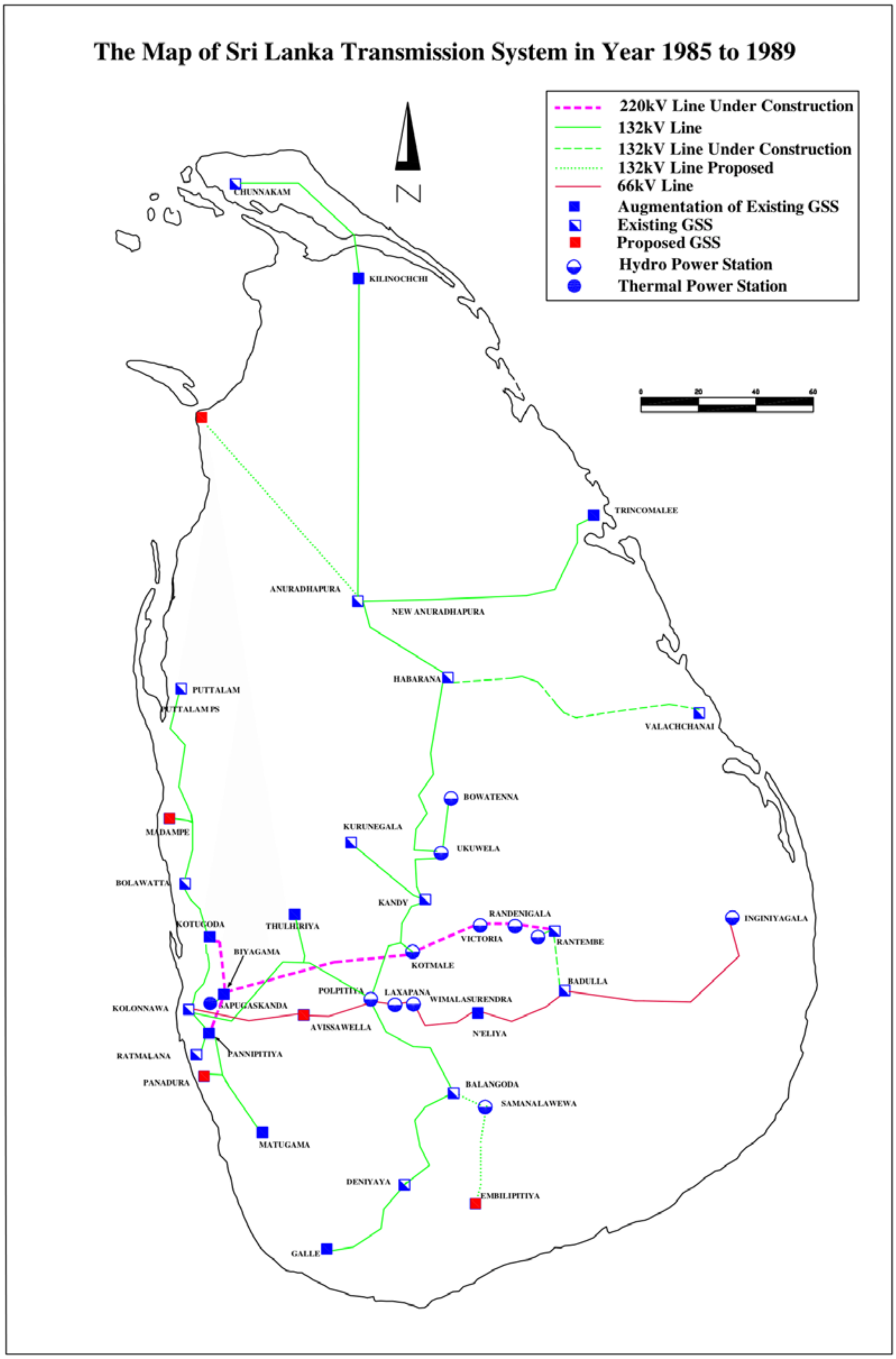

Figure 2.4: Sri Lanka Transmission Network Map from Year 1985 to 1989

Source: (Transmission Development Proposals 1985-1989)

2.4. Transmission Planning Criteria

When transmission system is modelled, system model should adhere to the transmission planning criteria mentioned as follows.

2.4.1. Voltage Criteria

The voltage criteria defines the allowable voltage deviation at any live bus bar of the network under normal operating conditions as well as under single contingency situation as depicted in Table 2.2.[1]

Table 2.2: Allowable voltage variations

Bus bar voltage	**Allowable voltage variation (%)**	
	Normal operating condition	**Single contingency condition**
220 kV	±5%	±10%
132kV	±10%	±10%

2.4.2. Thermal Criteria

The thermal criterion, limits the loading of any transmission network element, in order to avoid overheating and change of its mechanical and electrical properties due to excessive overload. The loading of elements should not exceed their rated thermal loading values for steady state conditions.Table 2.3 shows the thermal ratings of the ACSR (Aluminium Conductor Steel Reinforced), Zebra conductor as an example.

Table 2.3: Thermal ratings of ACSR, Zebra Conductor

Conductor	**Current Rating (A)**		**Power Rating (MVA)**			
			220 kV		**400 kV**	
	Normal	**Contingency**	**Normal**	**Contingency**	**Normal**	**Contingency**
Zebra	635	762	242	290	440	528
2xZebra	1270	1524	484	581	880	1056
4xZebra	2540	3048	968	1161	1760	2112

2.4.3. Security Criteria

The performance of the transmission system under contingency situation is taken into consideration in the security criteria. The adopted contingency level for the planning purposes is single contingency, N-1, i.e. outage of any one element of the transmission system at a time.

After an outage of any one element (i.e. any one circuit of a transmission line or a transformer and without any adjustment or corrective measure), the system should be able to meet the distribution demand while maintaining the bus bar voltage levels as given in Table 2.2 and loading of all the remaining elements should not exceed their emergency ratings specified.

After system readjustment following a disturbance, the voltage and loading of elements should return to their corresponding normal limits.

2.4.4. Stability Criteria

Stability criteria should ensure the system stability during and after a system disturbance.

For all pertaining equipment in service, the system should remain stable in case of:

- Three-phase fault at any one overhead line terminal, cleared by the primary protection with successful and unsuccessful auto re-closing
- Loss of any one generation unit
- Load rejection by loss of any transformer.

2.4.5. Short Circuit Criteria

The short circuit criteria limits the maximum three phase circuit currents at the 132kV, 33kV and 11kV bus bars of any grid substation (see Table 2.4 [1]), in order to protect the downstream transmission and distribution network elements.

Table 2.4: Allowable maximum 3 phase short circuit levels

Bus bar voltage	System	Maximum 3 Phase fault level (kA)
132kV and above	Overhead	40.0
	UG cable	40.0
33kV	Overhead	25.0
	UG cable	25.0
11kV	UG cable	25.0

Chapter 3

3. SYSTEM MODELLING

3.1. System configuration

Considering the port infrastructure facilities of Sri Lanka, there are only three potential locations to setup new coal power generation plants. They are Sampur, Ambalangoda and Hambanthota. Table 3.1 shows the generation scheduleof the future coal generation plants that was identified from Long Term Generation Expansion Plan 2013-2032 (LTGEP 2013-2032) [12]. Figure 3.1 shows how these future generating power plants are distributed among the potential three sites. For this study generation schedule and the locations given in Table 3.1 were used to prepare the two system models.

Table 3.1:Generation schedule as per the LTGEP 2013-2032

Year	**Plant size (MW)**	**Location**	**Capacity in each location (MW)**			
			Sampur	***Ambalangoda***	***Hambanthota***	***Total***
2018	2x250	Sampur	500	250	-	750
	1x250	Ambalangoda				
2019	1x250	Ambalangoda	500	500	-	1000
2020	1x300	Ambalangoda	500	800	-	1300
2021	1x300	Ambalangoda	500	1100	-	1600
2022	1x300	Sampur	800	1100	-	1900
2023	1x300	Ambalangoda	800	1400	-	2200
2024	1x300	Sampur	1100	1400	-	2500
2025	**1x300**	**Sampur**	**1400**	**1400**	**-**	**2800**
2027	1x300	Sampur	1700	1400	-	3100
2028	1x300	Hambanthota	1700	1400	300	3400
2030	1x300	Hambanthota	1700	1400	600	3700
2031	1x300	Hambanthota	1700	1400	900	4000
2032	**1x300**	**Hambanthota**	**1700**	**1400**	**1200**	**4300**

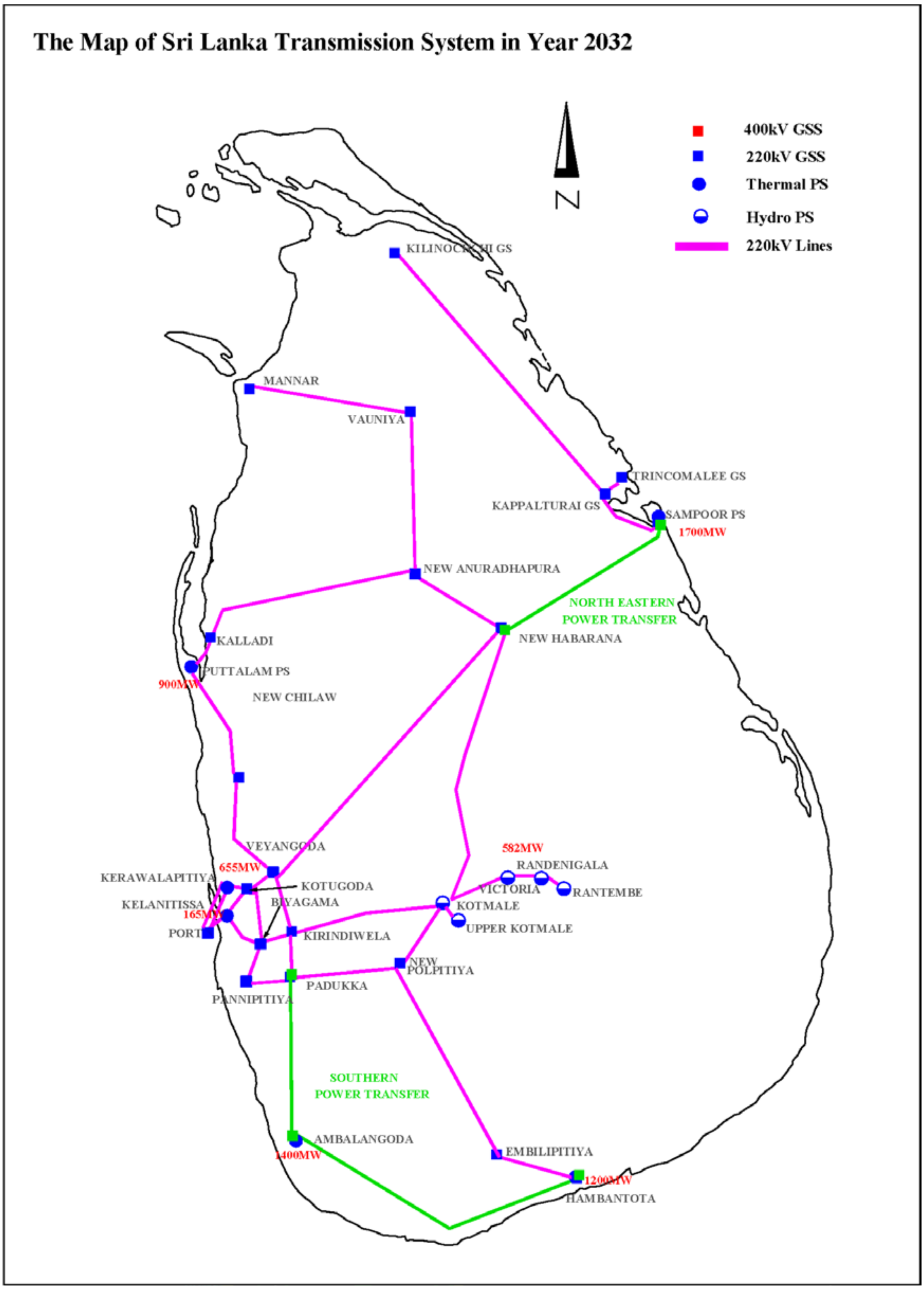

Figure 3.1 Sri Lanka Transmission Network Map in year 2032

Source: (Extracted from Long Term Transmission Development Plan 2013-2022)

The two transmission system configurations were developed considering the steady state and contingency conductor ratings (depicted in Table 2.3), transmission voltage and security criteria (N-1) mentioned inChapter 2 under transmission planning criteria in Section 2.4.

Based on the voltage level and the location of the power transfer there are four possible system configurations as stated below and their corresponding single line diagrams are shown in Figures 3.2 to 3.5

Option 1 (a): 220 kV southern interconnection

Option 1 (b): 220 kV north eastern interconnection

Option 2 (a): 400 kV southern interconnection

Option 2 (b): 400 kV north eastern interconnection

Option 1 (a): Southern Interconnection

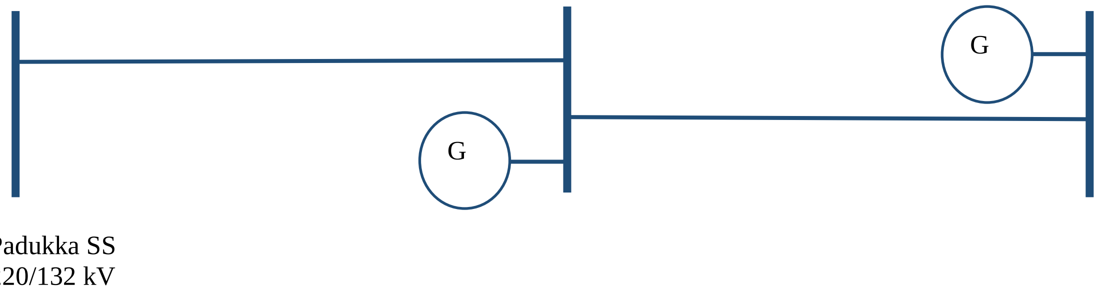

Figure 3.2: System configuration of 220 kV option for the Southern Interconnection

Option 1 (b): North Eastern Interconnection

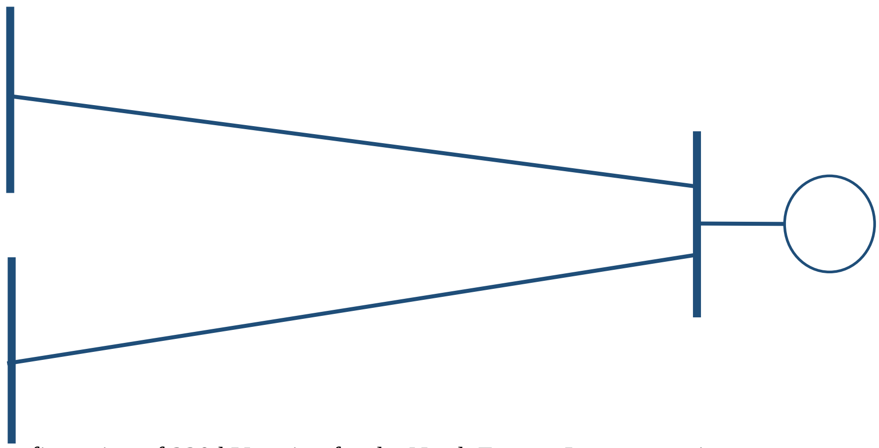

Figure 3.3: System configuration of 220 kV option for the North Eastern Interconnection

In this system configuration (option 1) for both southern interconnection (option 1(a)) and northeast interconnection (option 1 (b)),Zebra (ACSR) is used as the conductor. Considering the amount of bulk power transfer between generation stations and the load centers, quad bundle is used in order to increase the capacity of the transmission route. Further in the option 1(b), owing to the 1700 MW of power transfer, two separate transmission line routes wereconsidered in the north eastern power transmission. However in option 2 (b), single route was considered as it is sufficient to transferthe prescribed amount of power. For southern interconnection same configuration is used as in option 1 (a). However, in option 2 (a)multi- bundle (twin, quad) is used in order to mitigate the problems arise due to corona phenomena by minimizing corona effect on the transmission line.

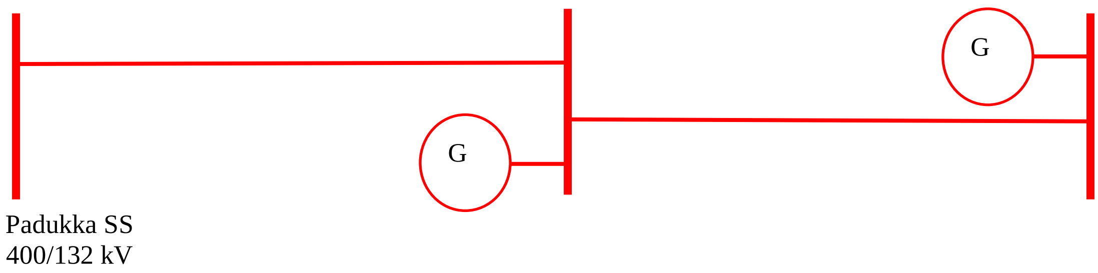

Figure 3.4: System configuration of 400 kV option for the Southern Interconnection

Option 2 (b): North Eastern Interconnection

Figure 3.5:System configuration of 400 kV option for the North Eastern Interconnection

3.2. Economical Transmission Voltage for the System Configurations

Economical transmission voltages were estimated based on the empirical equation 1.1, Table3.2summarizes the calculated economical voltages for each transmission line route considered in Southern and North Eastern interconnections. Sample calculation to obtain economical voltage of the Sampur – New Habaranasingle circuit transmission line route is as follows,

$$V_L = 5.5 \times \sqrt[2]{\left(\left(\frac{95}{1.6}\right) + \left(\frac{467 \times 1000}{0.9\times 1 \times 150}\right)\right)}$$

$$V_L = 326\ kV$$

Table 3.2: Economical Transmission Voltage

TransmissionLine	**Length (km)**	**Powerper phase (MW) 2025/2032**	**No of circuits**	**EconomicalVoltage (kV) 2025/2032**
Sampur- New Habarana (single route)	95	467/567	1	326/359
			2	233/256
Sampur- New Habarana (with second route Sampur –New Anuradhapura)	95	233/283	1	233/256
			2	167/183
Sampur-New Anuradhapura	105	233/283	1	233/256
			2	168/184
Ambalangoda-Padukka	72	467	1	325
			2	232
		233	1	232
			2	166
Ambalangoda-Hambanthota	145	233	1	235
			2	170

From the results shown in Table 3.2, it is observed that for Sampur - New Habarana transmission line 183 kV (220kV) is the best considering double circuit line if there are two routes. However if there is only one route, (in case of 400 kV option) 256 kV (275kV) voltage is selected as the economical voltage. For Sampur – New Anuradhapura transmission line, economical voltage is 184 kV (220 kV). For Ambalangoda –Padukka and Ambalangoda –Hambanthota transmission lines economical voltages are 166 kV (220 kV) and 170 kV (220 kV) respectively. However as this is an empirical formula, the estimated results are only a guide line for the transmission voltage selection process. This will be further analyzed in detail considering the voltage stability of the system.

3.3. Maximum Power Transmission Capability

Further analysis of the two options was carried out using the Surge Impedance Loading (SIL) of the transmission line routes. Table 3.3 illustrates the maximum power that can be transmitted through the different routes under two voltage options. The calculation was based on the Equations2.2, 2.3 and 2.4 and transmission line loadabilitycurve depicted in Figure 2.1

$$P(t) = 175 \times 2.75 = 481MW$$

Table 3.3: Maximum Power Transmission Capability of the Transmission Lines

TransmissionLine	**Voltage (kV)**	**Noof Bundle**	**Noof circuits**	**Multiplying Factor**	**SIL (MW)**	**P(t) (MW)**
Sampur- New Habarana	220	4	2	2.75	175	***481***
	400	4	2		647	1779
Sampur-New Anuradhapura	220	4	2	2.5	175	***438***
Ambalangoda-Padukka	220	4	2	3	175	***525***
	400	4	2		647	1941
Ambalangoda-Hambanthota	220	4	2	2.2	175	***385***
	400	4	2		647	1423

For north eastern power exchange, 400 kV option (with single route) displays higher power transfer capability than 220 kV option (with tworoutes). Further for southern power exchange, 400 kV option displays far better power transfer capability than 220 kV option. Therefore from the point of view of SIL, 400 kV voltage offers far more power transfer capability than 220 kV for the southern power transfer and for the north eastern power transfer. Though single circuit is considered for Ambalangoda - Padukka 400 kV transmission line (because power rating is more than enough), for the study it was taken as double circuit in order to improve the reliability of the line under contingency situation.

Chapter 4

4. STATIC VOLTAGESTABILITYANALYSIS

4.1. Introduction

Voltagestabilityreferstotheabilityofapowersystemtomaintainsteadyvoltages at all buses in the system and maintain or restore equilibrium between load demand andloadsupplyfromitsgiveninitialoperatingconditionsafterithasbeensubjected to a disturbance. Instability may result in progressive voltage falls or rises at some buses. A possible outcome of voltage instability is the loss of load in an area, and possibletrippingoftransmissionlinesandotherelementsbytheirprotectivesystems which can lead to cascading outages.

4.2. PV Analysis

PV curves play a major role in understanding and explaining voltage stability in a power system.PV analysis process involves in a series of continuous power flow solutions for increasing of active power (MW) transfers and monitoring what happens to the system voltage as a result. The relationship between the active power, ***P***and voltage, ***V*** is non-linear as shown in Figure 4.1.

Following equations 4.1[18] and 4.2[18]were derived as load flow equations for a lossless system which is used to calculate active and reactive power.

$$P = -\frac{EV}{X}\sin\theta \quad (4.1)$$

$$Q = -\frac{V^2}{X} + \frac{EV}{X}\cos\theta \quad (4.2)$$

Where,

P – Active power

Q– Reactive Power

E –Sending end voltage

V – Receiving end voltage

X– Reactance of the element

$\boldsymbol{\theta}$ − Load Angle

For a given load (P,Q), these two equations have to be solved with respect to V and θ in order to obtain the solutions for V. By eliminatingθ, from equation 4.1 and 4.2 following second order equation with respect to V^2 is obtained.

$$(V^2)^2 = (2QX - E^2)V^2 + X^2(P^2 + Q^2) = 0$$

The two solutions are as follows:

$$V = \sqrt[2]{\frac{E^2}{2} - QX \pm \sqrt[2]{\frac{E^4}{4} - X^2P^2 - XE^2Q}} \qquad (4.3)$$

According to equation 4.3[18], for a given load power below the maximum, there are two solutions: one with higher voltage and lower current, the other with lower voltage and higher current(Figure 4.1). The former corresponds to the normal operating conditions with voltage closer to the generator voltage and the latter corresponds to an unstable operating condition.

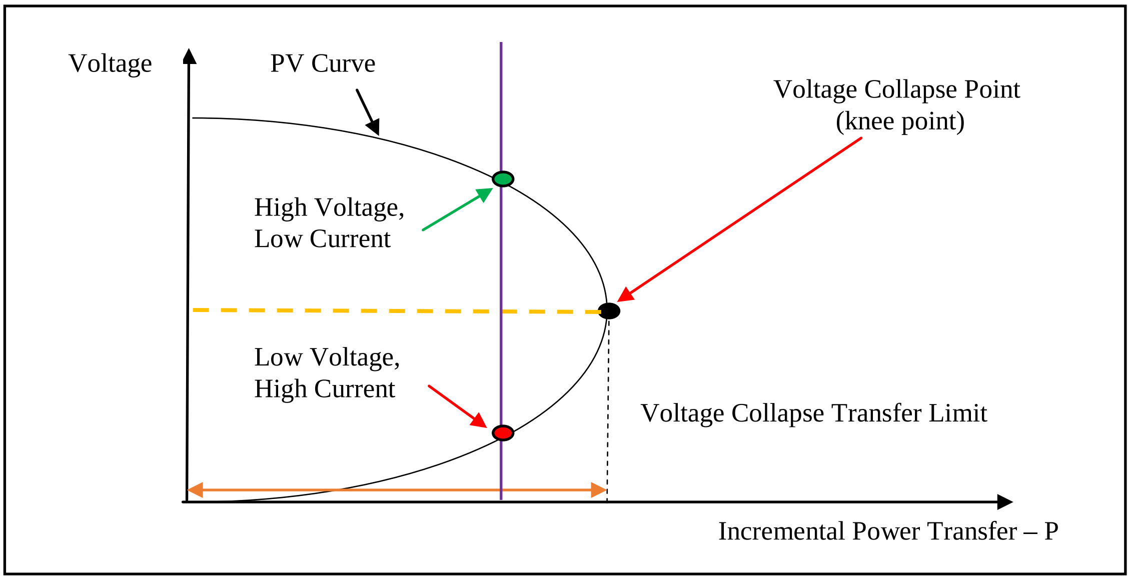

Figure 4.1: PV Curve

As the load is more and more compensated with reactive power compensation, the transfer of maximum power will be increased. However, the voltage at which this maximum occurs also increases. This situation is dangerous in the sense that maximum transfer capability may be reached at voltages close to normal operating values. Also, for a high degree of compensation and a load power close to the maximum, the two voltage solutions are close to each other and without further analysis it may be difficult to decide if a given solution is the “normal” one.

PV analysis is used to determine voltage stability of a power system. In this analysis power ***P*** at a particular area is increased in steps and voltage ***V*** is observed at some critical load buses and then curves for those particular buses will be plotted to determine the voltage stability of a system by static analysis.

4.2.1. Static voltage stability analysis on the Sri Lankan power system

Using the transmission network configurations for both options 1 and 2, continuous power flow analysis was done and PV curves were drawn for each critical load buses in years 2025 and 2032.PSS®Epower system analysis software toolwas used for the purpose of the simulation and construction of the PV curves. The PV curves for each critical bus for each power transfer are shown from Figures 4.2 to 4.7

From Figure 4.2, it is observed that for New Habarana – Sampur power transfer 1000 MW power is transferred without any voltage problems before reaching the voltage collapse point in both options 1 and 2 considering the New Habarana bus bar for the year 2025.

Considering Figure 4.3 and Figure 4.4, it is observed that for Ambalangoda power transfer, both option 1 and 2 shows 1400MW of power transfer for both Ambalangoda–Padukka and Ambalangoda–Hambanthota before reaching the voltage collapse point considering the Padukka and Hambanthota bus bars for the year 2025.

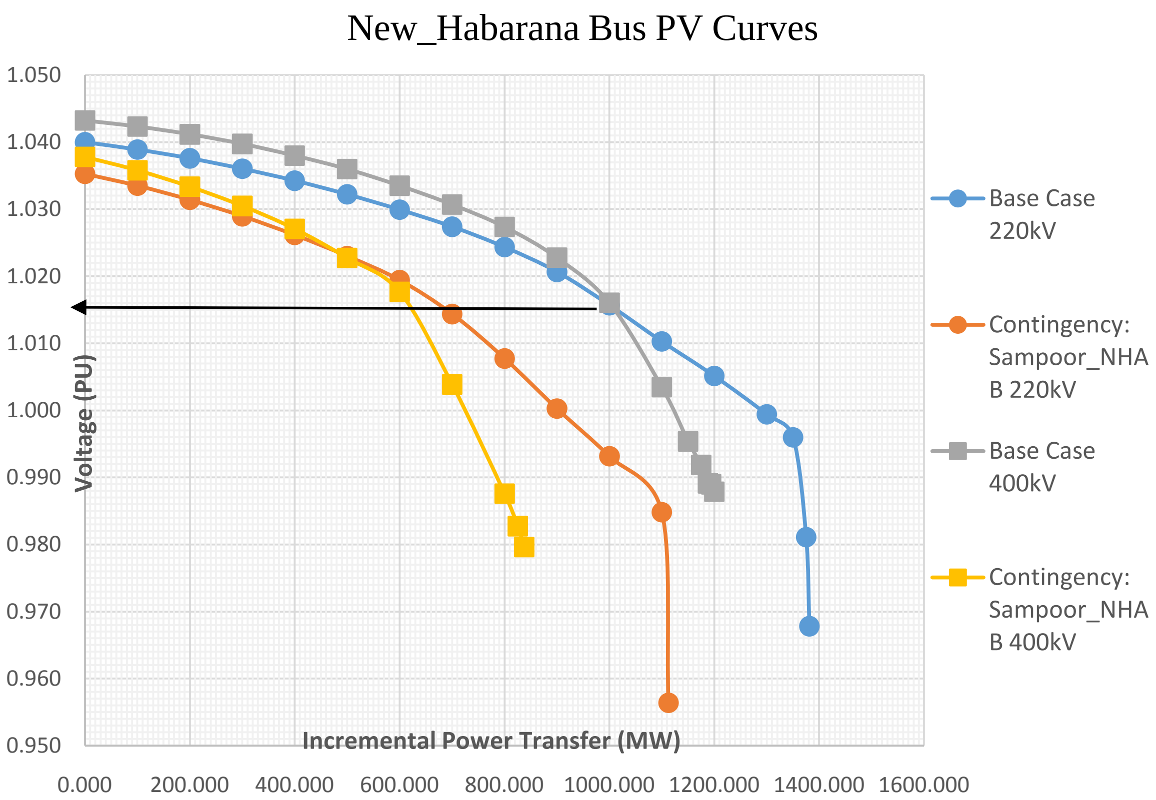

Figure 4.2: PV Curves for New Habarana Bus: Sampur Power Transfer – Year 2025

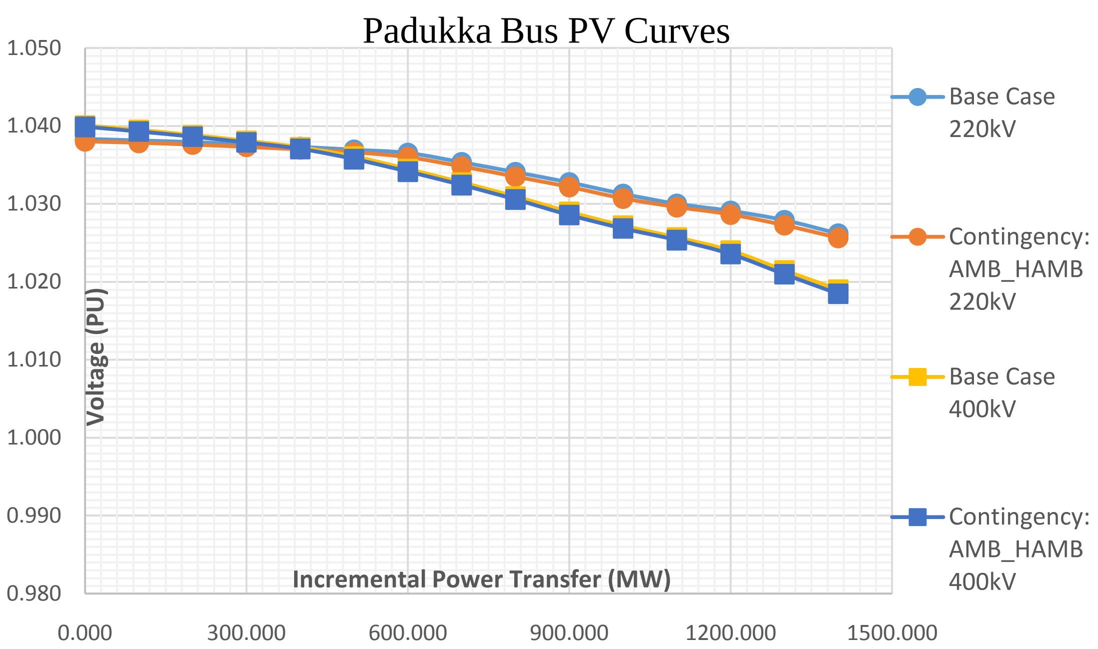

Figure 4.3: PV Curves for Padukka Bus: Ambalangoda Power Transfer – Year 2025

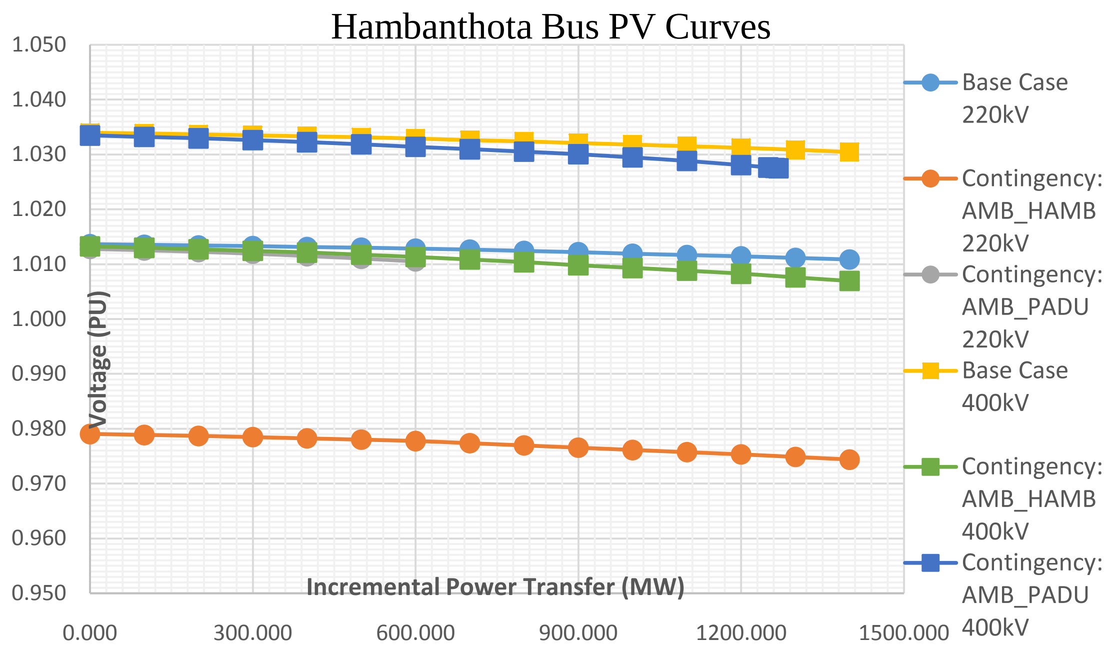

Figure 4.4: PV Curves for Hambanthota Bus: Ambalangoda Power Transfer – Year 2025

From Figure 4.5, it is observed that for New Habarana – Sampur power transfer both options 1 and 2 shows power transfer of 1400 MW without any problem considering the New Habarana bus bar for the year 2032.

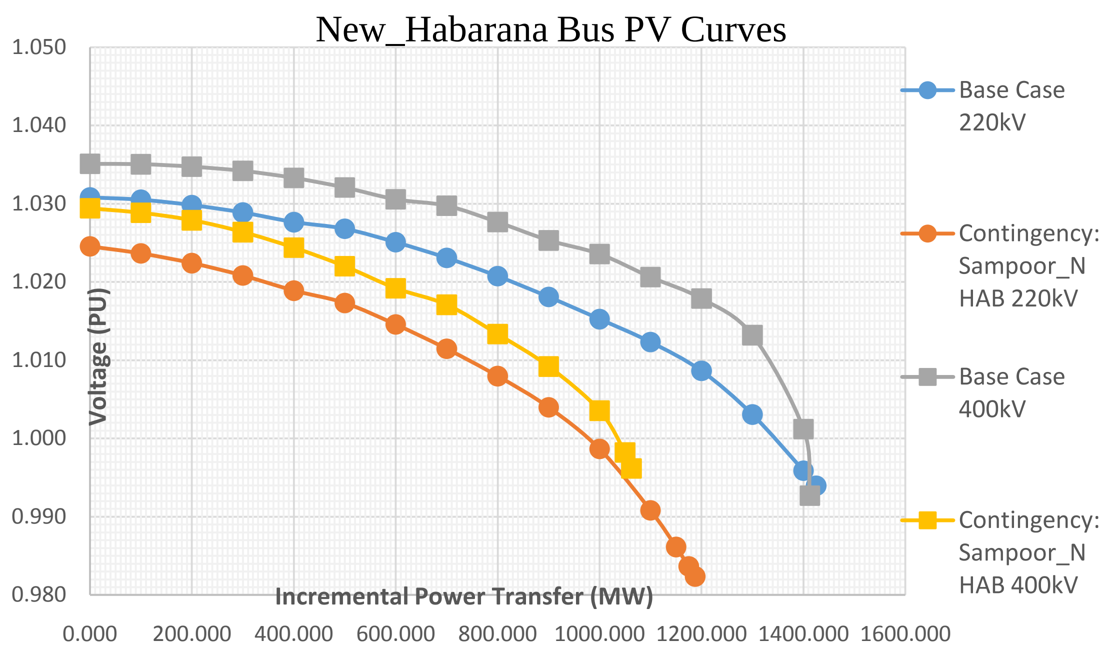

Figure 4.5: PV Curves for New Habarana Bus: Sampur Power Transfer – Year 2032

Considering Figure 4.6 and Figure 4.7, it is observed that for Ambalangoda power transfer, option 2 (400 kV) shows 3000 MW of power transfer and option 1 (220 kV) shows 2250 MW of power transfer considering the Padukka and Hambanthota bus bars for the year 2032. Therefore it is proved that option 2 performs better than the option 1 considering maximum power transfer with respect to voltage stability of the bus.

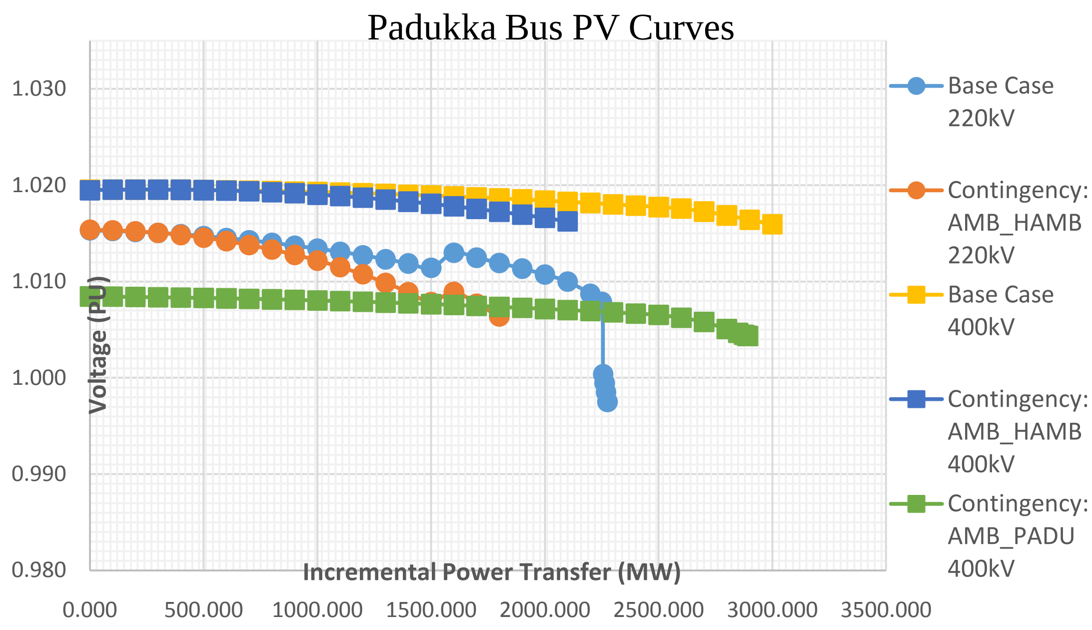

Figure 4.6: PV Curves for Padukka Bus: Ambalangoda Power Transfer – Year 2032

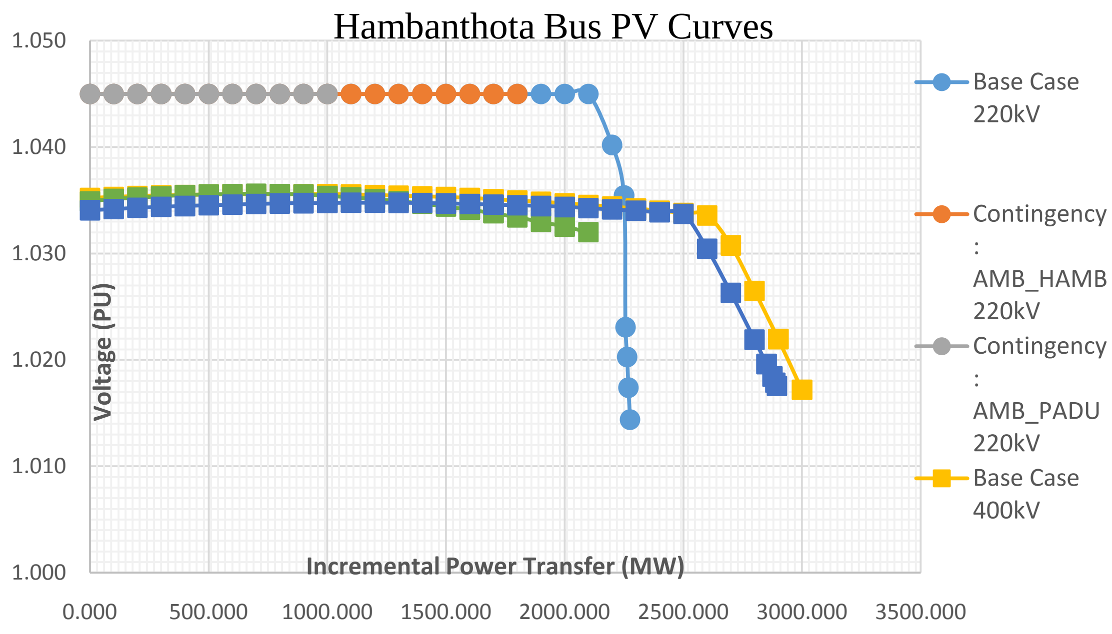

Figure 4.7: PV Curves for Hambanthota Bus: Ambalangoda Power Transfer – Year 2032

Considering steady state voltage stability analysis for power transfer, it is observed that 400kV (option 2) performs better than the 220kV (option 1) when more and more generation is added to the transmission network. However,it is noted that, this performance is not significant when the amount of power transfer at Sampur is considered. For all the cases it is seen that the amount of maximum power that can be transferred from Sampur is almost the same in both option 1(b) and 2(b). This is because, for 400 kV option there is only one transmission line route with double circuits and for 220 kV there are two routes with double circuits. The maximum power transfer capability of southern power transfer (a) is more than north eastern power transfers (b), becauseload centers are also located distant from generation in north eastern power transfer compared to southern power transfer. Therefore it is seen that for southern (Ambalangoda) power transfer (a), there is about 500MW to 1000MW difference between the two options.

4.3. QV Analysis

A QV curve expresses the relationship between the reactive power support Q at a given bus and voltage at that bus. This is determined by connecting a fictitious generator with zero active power and recording the reactive power Q produced as the terminal voltage V is being varied. Because it does not produce active power, this fictitious generator is often referred to as synchronous condenser.

Following equation 4.1 [18] shows the load flow equation for active power and the equation 4.4 [18] shows the power flow equation for reactive power for a lossless system. Q_c is the reactive power injected by the fictitious generator as mentioned above.

$$P = -\frac{EV}{X}\sin\theta \tag{4.1}$$

$$Q - Q_c = -\frac{V^2}{X} + \frac{EV}{X}\cos\theta \tag{4.4}$$

Where,

$\boldsymbol{P}$ – Active power | $\boldsymbol{Q}$– Reactive Power

$\boldsymbol{E}$ –Sending end voltage | $\boldsymbol{V}$ – Receiving end voltage

$\boldsymbol{X}$– Reactance of the element | $\boldsymbol{\theta}$ – Load Angle

$\boldsymbol{Q_c}$ – Reactive power injected by fictitious generator

From equation 4.1 load angle θ is calculated for a particular instance. Then this calculated value is taken as an input to the equation 4.4 and obtains the reactive power, Q_c that needs to be injected to maintain the selected bus at a given voltage level. This will be continuously done in order to obtain the QV curves illustrated in the Figure 4.8.

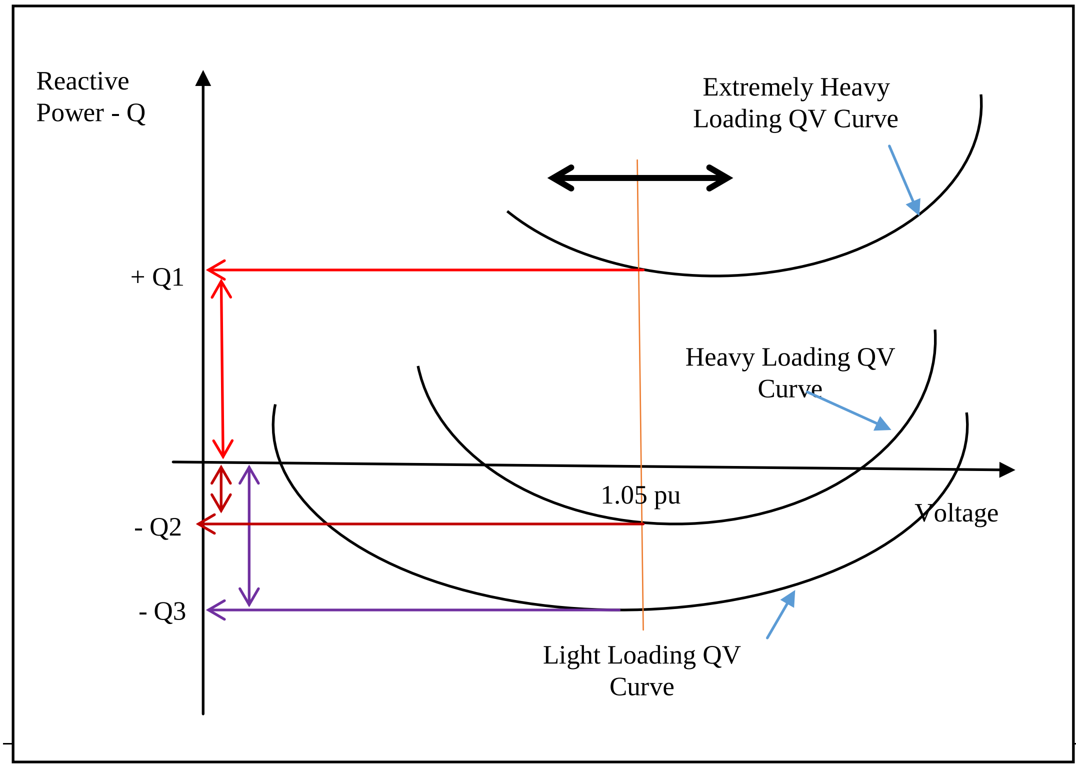

Figure 4.8: QV Curves

Figure 4.8 shows different types of QV curves drawn under different loading conditions. It shows that when system is under extremely heavy loading conditions, in order to maintain the bus voltage at 1.05pu, Q1 amount of reactive power needs to be injected to the bus. For heavy loading and light loading conditions, Q2 and Q3 amount of reactive power absorption is required at the bus to maintain its’ voltage at 1.05pu respectively. These reactive power requirements can be found depending upon the voltage which needs to be maintained in that selected bus.

QV curves were drawn for each critical load buses in years 2025 and 2032 for both options. PSS®Ewas used for the purpose of the simulation and plotting of QV curves. The QV curves drawn for each critical bus for each power transfer are shown from Figures 4.9 to 4.12. From each curve, reactive power requirement is obtained and compared with the two options.

Considering the Figure4.9, it is observed that for New Habarana220kV bus bar, the reactive power compensation required to maintain 1.05 pu voltage is 220Mvar for both 220kV and 400kV options in the year 2032. However, to maintain it in 1.0 pu voltage at New Habarana220kV bus bar, the required reactive power compensation is -300Mvar and -440Mvar for 220kV and 400kV options respectively.

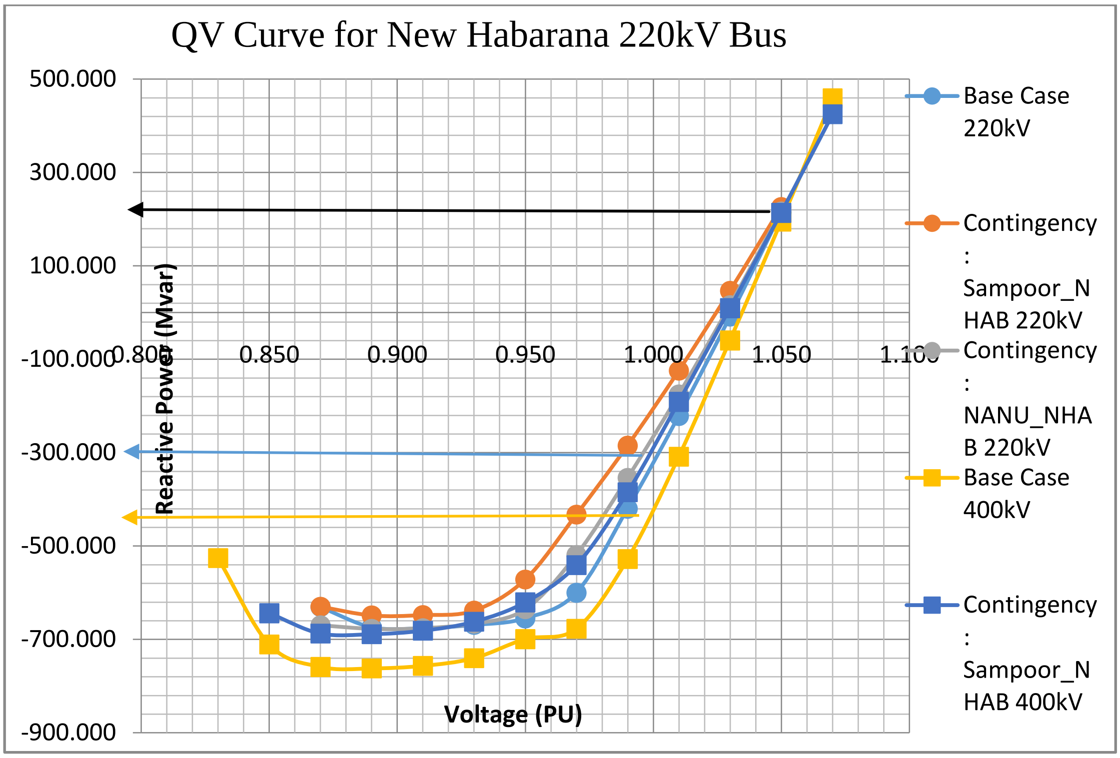

Figure 4.9: QV Curves for New Habarana Bus: Sampur Power Transfer – Year 2032

Figure 4.10 shows that for Sampur 220 kV bus bar, the reactive power compensation required to maintain 1.05 pu voltage is 360 Mvar for 220 kV and 80 Mvar for 400 kV option in the year 2032. However to maintain it in 1.0 pu voltage at Sampur 220 kV bus bar, reactive power compensation required is -160 Mvar and -360 Mvar for 220 kV and 400 kV options respectively. Therefore it is proven that 400 kV option performs better regarding the reactive power compensation in order maintain the voltage of New Habarana and Sampur area inside the statutory limits for Sampur power transfer.

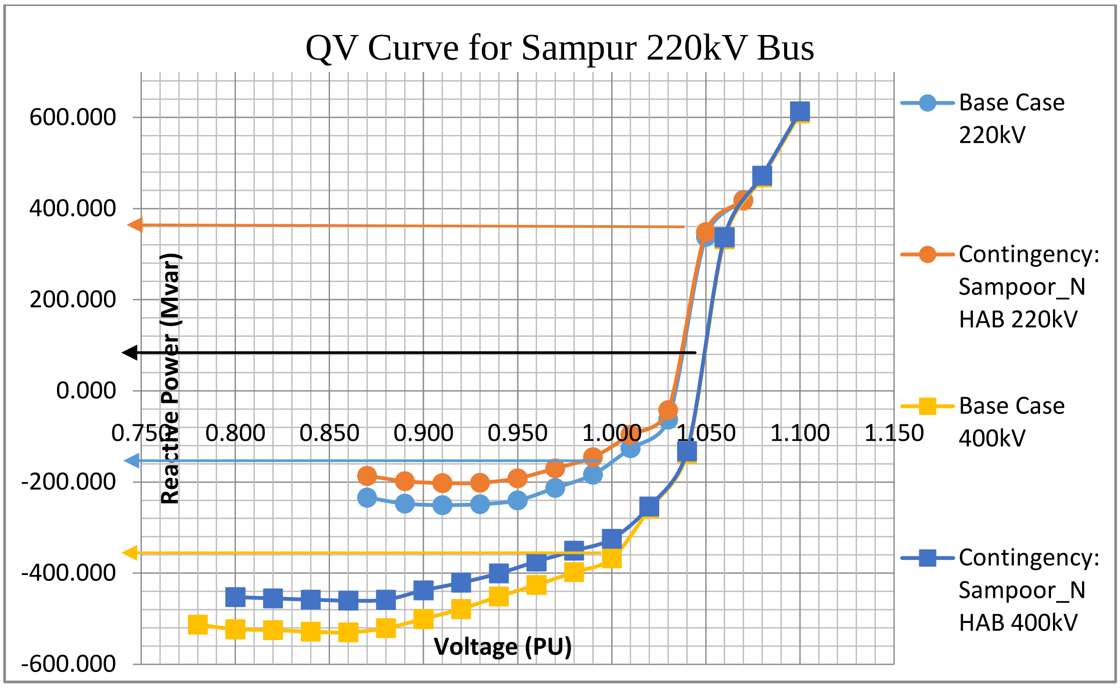

Figure 4.10: QV Curves for Sampur Bus: Sampur Power Transfer – Year 2032

Furthermore considering the Ambalangoda power transfer, Figure4.11 shows that for Ambalangoda bus bar, the reactive power compensation required to maintain 1.0 pu voltage is -40Mvar for 220kV and -255Mvar for 400kV option in the year 2032.

Figure 4.12 shows that for Hambanthota bus bar, the reactive power compensation required to maintain 1.0 pu voltage is -140Mvar for 220kV and -500 Mvar for 400kV option in the year 2032. Therefore it is proven that 400 kV option performs better regarding the reactive power compensation in order maintain the voltage of Amabalangoda and Hambanthota area inside the statutory limits for Ambalangoda power transfer.

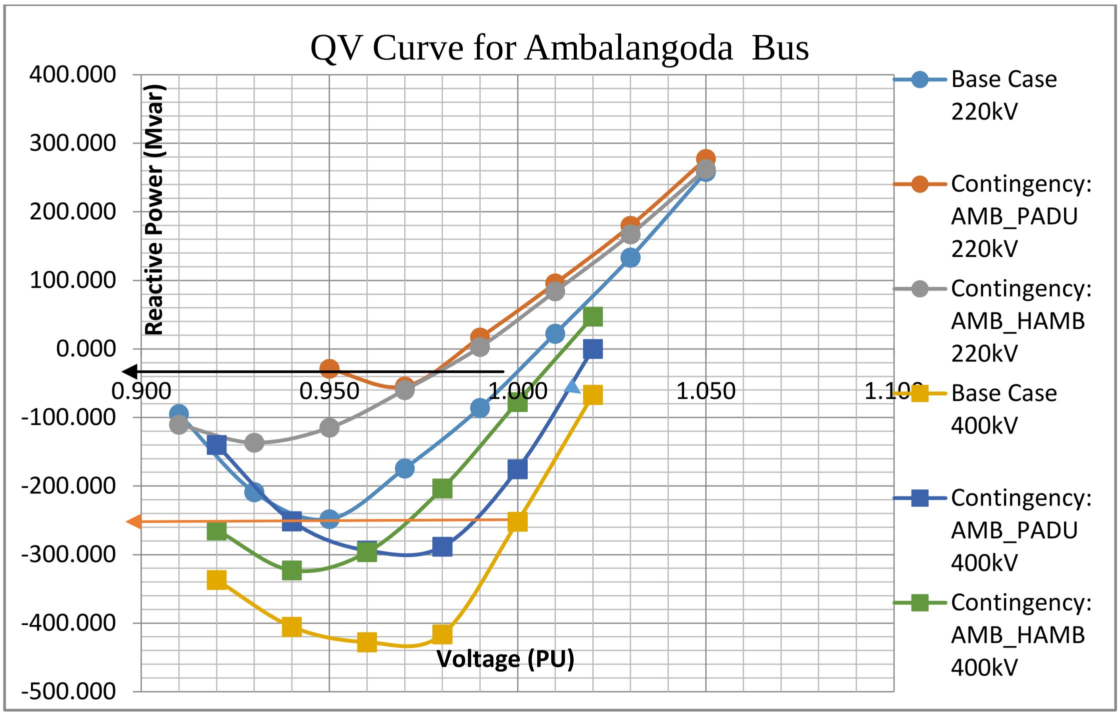

Figure 4.11: QV Curves for Ambalangoda Bus: Ambalangoda Power Transfer – Year 2032

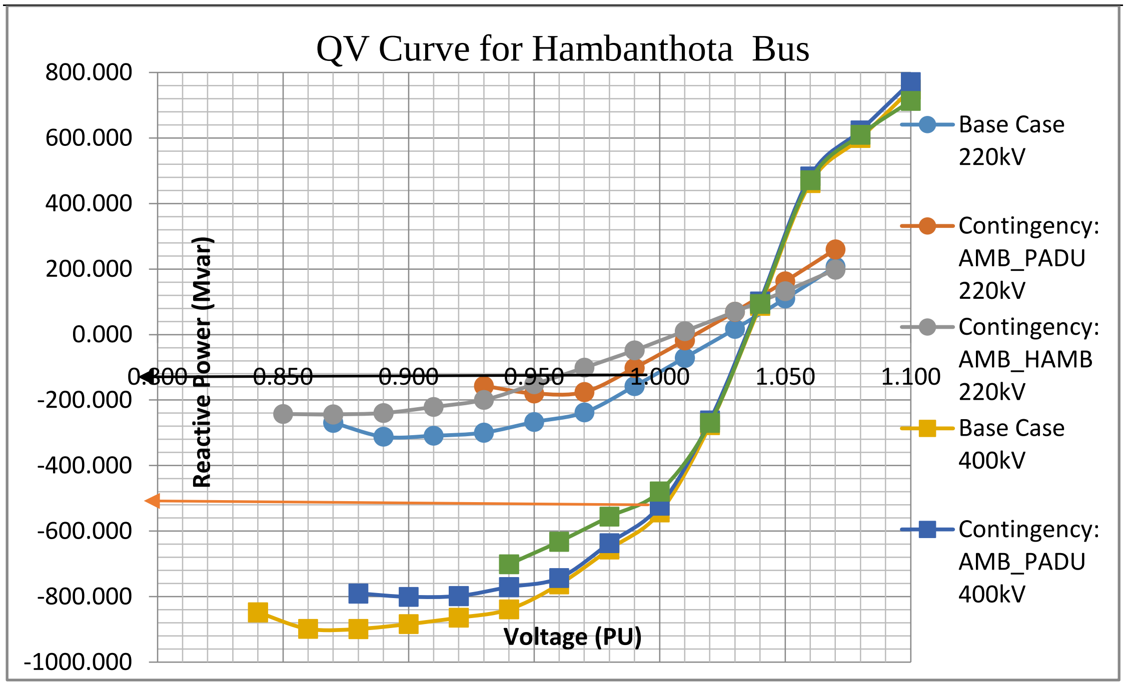

Figure 4.12: QV Curves for Hambanthota Bus: Ambalangoda Power Transfer – Year 2032

4.4. Results and Conclusions

Therefore as a conclusion it is observed that for Southern province power transfer 400 kV voltage prefers over 220 kV voltage. However for North Eastern power transfer there is no distinct advantage of 400 kV over 220kV voltage. From reliability wise also 220 kVoption is better than 400 kV optionin this case.

Further from QV curves it shows that there is no need for reactive power compensation for both options.

Thus it is concluded that there is a significant voltage profile improvement in 400 kV option compared to 220 kV option considering Southern power transfer and little voltage improvement in North Eastern power transfer. Therefore 400 kV is technically feasible over 220 kV considering Southern power transfer.

Chapter 5

5. ECONOMIC ANALYSIS

5.1. System Losses

System peak power losses were calculated using the PSS®E simulation, for all the scenarios between the two 220kV and 400kV voltage options. Following Table 5.1 shows the peak power loss saving from 400kV option compared to 220kV option, obtained through those losses which were calculated. The losses were calculated for two options for each scenario as follows;

- Day Peak Hydro Maximum
- Day Peak Thermal Maximum
- Night Peak Hydro Maximum
- Night Peak Thermal Maximum

These four scenarios were formulated depending on the load and generation mix. Then the loss difference between the two options, for the four scenarios were tabulated under Table 5.1

Table 5.1: Peak Power Loss Saving

Year	Load and Generation Scenarios			
	Day Peak Hydro Maximum (MW)	**Day Peak Thermal Maximum (MW)**	**Night Peak Hydro Maximum (MW)**	**Night Peak Thermal Maximum (MW)**
2025	0.08	2.61	1.02	***5.23***
2026	14.65	14.65	8.95	***12.35***
2027	13.82	17.89	10.53	***13.34***
2028	12.98	21.14	12.12	***14.32***
2029	12.15	24.38	13.70	***15.31***
2030	11.31	27.62	15.28	***16.29***
2031	15.35	25.25	17.26	***18.17***
2032	19.38	22.87	19.23	***20.05***

From the above table it is observed that for all four scenarios the loss saving increased with time. However for the economic analysis, night peak thermal maximum scenario was chosen and the loss saving from that scenario is used.

In order to calculate energy loss through loss load factor, night peak power loss figure needs to be used. Therefore Night peak scenario is chosen. Thermal Maximum scenario was selected, because in the future most of the generation will be from thermal and generation mix will be a thermal maximum scenario except for a short period hydro maximum mix. Therefore it was prudent to select the peak power losses of the Night Peak Thermal Maximum scenario.

From peak power loss figures of night peak thermal maximum scenario,Annual Energy saving is calculated using the load factors and Loss Load factors. Load factors were found from the Long Term Generation Expansion Plan [12] for each year and the Loss Load factors were calculated usingthe following empirical equation 5.1 [20].

$$\text{Loss Load Factor} = 0.2 \times Load\ factor + 0.8 \times (Load\ Factor)^2 \quad (5.1)$$

Then using the average cost per unit in the year 2014 published in Statistical Digest 2014 [8] i.e. Rs. 19.97, monetary saving is calculated. Table 5.2 shows the energy saving between option 1 and option 2.

Considering year 2025 as the beginning of the economic analysis, and 30 years as the life span of the investment, system loss saving for a period of 30 years is calculated. By using the calculated loss figures from 2025 to 2032, loss saving is extrapolated using the time trend. Figure 5.1 shows the trend line and the trend equation.

Table 5.2: Energy Saving

Year	Peak Power Loss Saving (MW)	Load Factor	Loss Load Factor	Annual Energy Saving (GWh)	Monetary Saving (Rs. Million)
2025	5.23	0.588	0.3942	18.1	360.66
2026	12.35	0.587	0.3931	42.5	849.19
2027	13.34	0.587	0.3931	45.9	916.91
2028	14.32	0.594	0.4011	50.3	1004.72
2029	15.31	0.594	0.4011	53.8	1073.83
2030	16.29	0.594	0.4011	57.2	1142.94
2031	18.17	0.593	0.3999	63.7	1271.19
2032	20.05	0.593	0.3999	70.2	1402.71

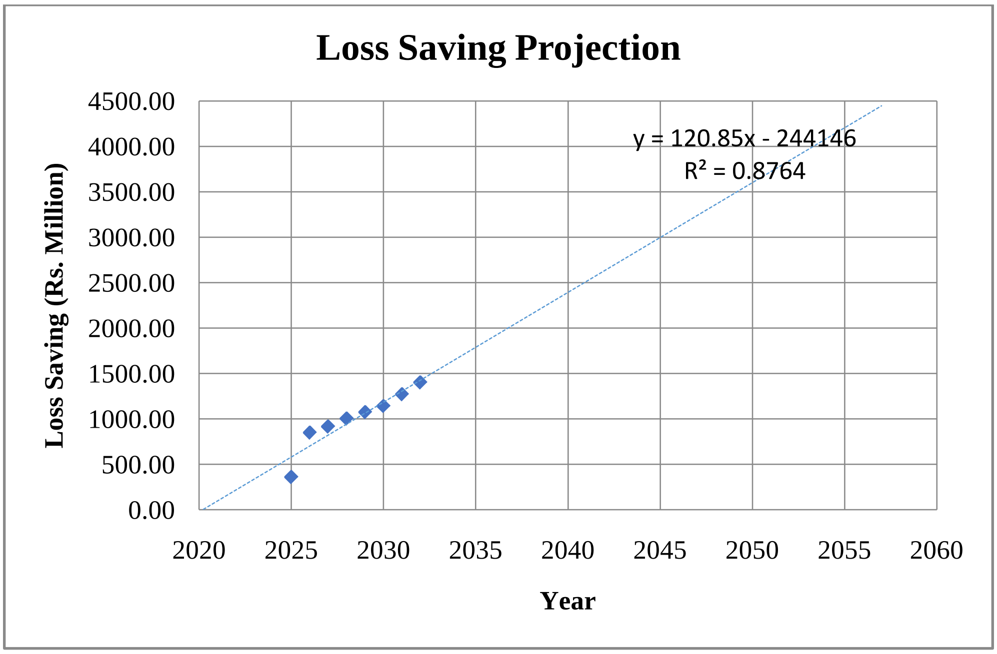

Figure 5.1: Loss Saving Projection

5.2. System Cost

Table 5.3 shows the cost involving the development of both 220kV and 400kV options. From that, investment difference is calculated in order to analyze the economic feasibility of the two options.

Table 5.3: System cost

Description	Total Cost (Rs. Million)					
	220kV option		400kV option		Difference	
	FC	LC	FC	LC	FC	LC
Sampur Development	14,175	4,381	16,076	3,482	1,901	-899
Ambalangoda Development	15,752	4,849	27,270	6,113	11,518	1,264
					13,418	365
					Total Investment Difference	**13,783**

5.3. Economic Analysis Indicators

Economic analysis was carried out using economic indicators such as Economic Internal Rate of Return (EIRR), Net Present Value and Cost Benefit analysis (B/C).

5.3.1. Net Present Value (NPV)

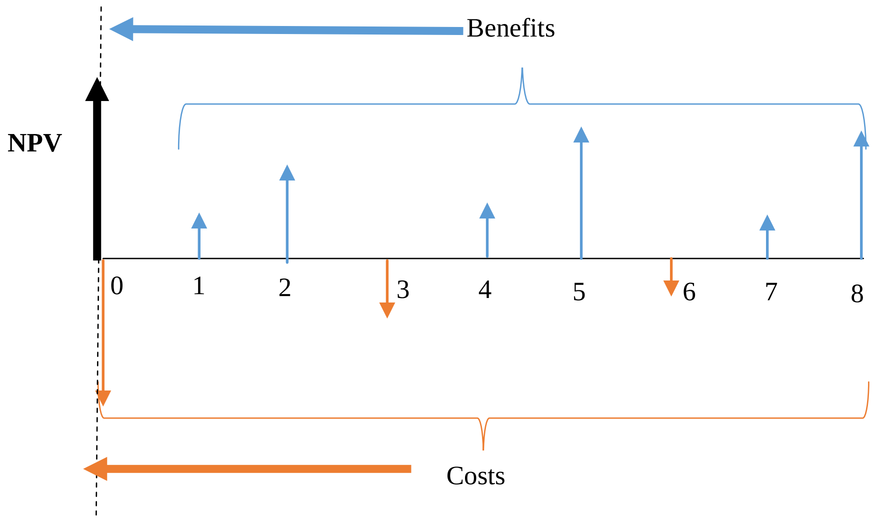

Figure 5.2 Cash flow of a project

Net present value, examines the total value of all cash flows to the present year or the zeroth year. The example of a cash flow is shown in Figure 5.2 and Equation 5.1 [22] shows how to calculate NPV through the cash flow analysis.

$$NPV = \sum_{n=1}^{N} \frac{C_n}{(1+i)^n} = \text{PW (Benefits)} - \text{PW (Costs)} \qquad (5.1)$$

Where,

$\boldsymbol{C_n}$– (Benefit – Cost) $\boldsymbol{i}$– Discount rate

n – No. of years (time period) ***PW***- Present worth

Economic feasibility of a project is acceptable if NPV > 0

5.3.2. Economic Internal Rate of Return (EIRR)

Economic Internal Rate of Return (EIRR) is defined as the discount rate that results in a net present value of zero. This is also an interpreted as return on investment for private projects. Equation 5.2 shows how to calculate EIRR.

$$NPV = 0 \Rightarrow\!\!> \sum_{n=1}^{N} \frac{C_n}{(1+EIRR)^n} = 0 \qquad (5.2)$$

Where

NPV – Net Present Value ***C_n*** – (Benefit – Cost)

n – No. of years (time period)

5.3.3. Cost Benefit Analysis (B/C)

The most common way to investigate the feasibility of public projects is by benefit to cost analysis. This is the ratio between the discounted benefit to cost where it should be greater than 1 in order to project to be economically feasible.

The following assumptions were made for the economic analysis,

1. Project work commissioned in the year 2025
2. Transmission Operation and Maintenance cost is taken as 1% of the investment cost
3. Cost is taken as the difference between the two options
4. Discount rate of 10% is taken for the NPV and B/C analysis
5. Lifetime of the project is taken as 30 years and economic analysis is done for 30 years' time horizon.

The following are the results obtained for the base case economic analysis:

- Economic Internal Rate of Return (EIRR) : 10.8% (> 10%)
- Net Present Value (NPV) : Rs. Million 1250 (> 0)
- Benefit to Cost Ratio : 1.082 (> 1)

Detailed analysis is tabulated inTables5.4,5.5 and5.6.

Table 5.4: EIRR Calculation

Year	**Cost in (MLKR)**			**Benefit due to Loss reduction (MLKR)**	**Net Benefit (MLKR)**
	Investment	**Trans. O&M cost**	**Total Cost**		
2025	13784	137.8	13921.8	360.7	-13561.2
2026		137.8	137.8	849.2	711.3
2027		137.8	137.8	916.9	779.1
2028		137.8	137.8	1004.7	866.9
2029		137.8	137.8	1073.8	936.0
2030		137.8	137.8	1142.9	1005.1
2031		137.8	137.8	1271.2	1133.3
2032		137.8	137.8	1402.7	1264.9
2033		137.8	137.8	1542.0	1404.2
2034		137.8	137.8	1662.9	1525.1
2035		137.8	137.8	1783.8	1645.9
2036		137.8	137.8	1904.6	1766.8
2037		137.8	137.8	2025.4	1887.6
2038		137.8	137.8	2146.3	2008.5
2039		137.8	137.8	2267.1	2129.3
2040		137.8	137.8	2388.0	2250.2
2041		137.8	137.8	2508.8	2371.0
2042		137.8	137.8	2629.7	2491.9
2043		137.8	137.8	2750.5	2612.7
2044		137.8	137.8	2871.4	2733.6
2045		137.8	137.8	2992.3	2854.4
2046		137.8	137.8	3113.1	2975.3
2047		137.8	137.8	3233.9	3096.1
2048		137.8	137.8	3354.8	3217.0
2049		137.8	137.8	3475.6	3337.8
2050		137.8	137.8	3596.5	3458.7
2051		137.8	137.8	3717.3	3579.5
2052		137.8	137.8	3838.2	3700.4
2053		137.8	137.8	3959.0	3821.2
2054		137.8	137.8	4079.9	3942.1
2055		137.8	137.8	4200.8	4062.9
				EIRR	**10.8%**

Table 5.5: NPV analysis

Year	Total Cost (MLKR)	Benefit due to Loss reduction (MLKR)	Net Benefit (MLKR)	Discounted Total (MLKR)	Cumulative Total (MLKR)
2025	13921.8	360.7	-13561.2	-13561	-13561
2026	137.8	849.2	711.3	647	-12915
2027	137.8	916.9	779.1	644	-12271
2028	137.8	1004.7	866.9	651	-11619
2029	137.8	1073.8	936.0	639	-10980
2030	137.8	1142.9	1005.1	624	-10356
2031	137.8	1271.2	1133.3	640	-9716
2032	137.8	1402.7	1264.9	649	-9067
2033	137.8	1542.0	1404.2	655	-8412
2034	137.8	1662.9	1525.1	647	-7765
2035	137.8	1783.8	1645.9	635	-7131
2036	137.8	1904.6	1766.8	619	-6511
2037	137.8	2025.4	1887.6	601	-5910
2038	137.8	2146.3	2008.5	582	-5328
2039	137.8	2267.1	2129.3	561	-4768
2040	137.8	2388.0	2250.2	539	-4229
2041	137.8	2508.8	2371.0	516	-3713
2042	137.8	2629.7	2491.9	493	-3220
2043	137.8	2750.5	2612.7	470	-2750
2044	137.8	2871.4	2733.6	447	-2303
2045	137.8	2992.3	2854.4	424	-1879
2046	137.8	3113.1	2975.3	402	-1477
2047	137.8	3233.9	3096.1	380	-1096
2048	137.8	3354.8	3217.0	359	-737
2049	137.8	3475.6	3337.8	339	-398
2050	137.8	3596.5	3458.7	319	-79
2051	137.8	3717.3	3579.5	300	221
2052	137.8	3838.2	3700.4	282	504
2053	137.8	3959.0	3821.2	265	769
2054	137.8	4079.9	3942.1	249	1017
2055	137.8	4200.8	4062.9	233	1250
				NPV	**1250**

Table 5.6: Benefit to Cost Ratio

Year	Total Cost (MLKR)	Benefit due to Loss reduction (MLKR)	Discounted Benefit (B)	Discounted Investment (C)
2025	13921.8	360.7	361	-13922
2026	137.8	849.2	772	-125
2027	137.8	916.9	758	-114
2028	137.8	1004.7	755	-104
2029	137.8	1073.8	733	-94
2030	137.8	1142.9	710	-86
2031	137.8	1271.2	718	-78
2032	137.8	1402.7	720	-71
2033	137.8	1542.0	719	-64
2034	137.8	1662.9	705	-58
2035	137.8	1783.8	688	-53
2036	137.8	1904.6	668	-48
2037	137.8	2025.4	645	-44
2038	137.8	2146.3	622	-40
2039	137.8	2267.1	597	-36
2040	137.8	2388.0	572	-33
2041	137.8	2508.8	546	-30
2042	137.8	2629.7	520	-27
2043	137.8	2750.5	495	-25
2044	137.8	2871.4	469	-23
2045	137.8	2992.3	445	-20
2046	137.8	3113.1	421	-19
2047	137.8	3233.9	397	-17
2048	137.8	3354.8	375	-15
2049	137.8	3475.6	353	-14
2050	137.8	3596.5	332	-13
2051	137.8	3717.3	312	-12
2052	137.8	3838.2	293	-11
2053	137.8	3959.0	275	-10
2054	137.8	4079.9	257	-9
2055	137.8	4200.8	241	-8
			16471	-15221
			Benefit/Cost	**1.0821**

5.4. Sensitivity Analysis

After the base case scenario, following four sensitivity cases were analyzed.

1. Reducing discount rate from 10% to 5%
2. Considering annual electricity cost increase of 5%
3. Considering increase of Transmission Operation and Maintenance cost percentage from 1% to 2%
4. Taking generation energy unit cost as10.73 LKR/kWh and average generation capacity cost as 1.2 MLKR/MW[23],[24] for calculation of monetary cost

Table 5.7 shows the results of the sensitivity analysis carried out for each of economic analysis.The detailed calculation sheets of the sensitivity analysis areshown in Appendix A.

Table 5.7: Sensitivity analysis

Economic Analysis Indicator	**Sensitivity Cases**				
		1	**2**	**3**	**4**
	Base Case	**Discount rate 5%**	**5% annual electricity cost increase**	**2% Transmission O&M cost percentage**	**Taking Generation Energy costand capacity cost only**
EIRR (%)	10.8	10.8	11.2	***9.9***	***5.7***
NPV (Rs. Million)	1250	15642	2074	***-187***	***-6081***
B/C	1.08	1.98	1.14	***0.99***	***0.60***

Case 1 shows as the best sensitivity case in favor of the 400 kV option, considering net present value and benefit to cost ratio. However from the point of view of the EIRR, case 2 is also favorable towards the 400 kV option. Further there is a high probability that this case can be materialized,because, there is a highprobability of increasing electricity tariff in the future with the increase of cost of generation. In case 3,with the increase of the transmission operation and maintenance cost by 1%, and in case 4 considering only generation energy cost figure, it makes economic feasibility in favor of 220 kV option.

5.5. Conclusion

Economic analysis between the two options shows that 400 kV option is better than the 220 kV option under base case and several sensitivity cases. Though it shows better economic feasibility results, it is marginally higher than the international standard norm. (International standard norm to justify the project feasibility is 10% [21]). This is because EIRR for base case is slightly (0.8%) higher than 10% However,except for the case 3 and 4, the other two cases also shows favorable EIRR figures (greater than 10%). When NPV is considered, base case, case 1 and 2 shows positive values and case 3 and 4 shows negative values again showing case 3 and 4 being unfavorable cases towards 400 kV option. The cost benefit analysis also shows the same.

Therefore considering the economic feasibility analysis, it is concluded that 400 kV option is economically feasible over 220 kV due toloss saving obtained through 400 kV.

Chapter 6

6. CONCLUSIONS AND FURTHER RESEARCHAREA

6.1. Conclusion

The research project is about the selection of voltage between 220 kV and 400 kV for the future transmission interconnection of bulk power transmission lines in Sri Lanka power system. The study was mainly focused on the major bulk power transmission from Sampur, Ambalangoda and Hambanthota generation stations to the load centers.

First data related for 400 kV was collected. Then two different system configurations weredeveloped based on the two system voltages, 220 kV versus 400 kV for years 2025 and 2032 and they were modeled in PSS®E (Power System Simulator for Engineering) software. Next, theoretical justification was developed and performed voltage stability studies (PV, QV analysis) in order to find out the technical feasibility of the two system configurations. Finally, the economic analysis between the two configurations was carried out to evaluate the economic feasibility of the two options.

According to the technical analysis on the power system, it shows that there is no significant reactive power compensation needed to operate power system in both options. However 400 kV option improves the voltage profile of the system than 220 kV voltage. The voltage improvement is significant for the Southern power transfer than the North Eastern power transfer. Further maximum power transfer capability of the southern power transfer shows significantly high capability in 400 kV than 220 kV.

Economic feasibility analysis mainly governs by the loss saving achieved through 400 kV voltage option over 220 kV voltage option. For base case and other several sensitivity cases other than one case, 400 kV option shows better economic feasibility than 220 kV option.

Therefore as a final conclusion, 400 kV option is recommended over 220 kV option considering both technical and economic factors.

6.2. Further research area

This study can be further enhanced by introducing following factors to the technical and economic analysis

1. Modeling of minimum generation and load scenario in order to find the inductive reactive power requirement under low load condition
2. Technical aspects: Conductor type optimization (Low Loss Conductor), transmission tower optimization
3. Economic aspects: Costing of Right of Way (ROW), Costing of corona loss effect and future escalation of land prices and Emission cost (environmental cost) into economic analysis

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Appendix A –Detailed Calculation Sheets of the Sensitivity Analysis

Case 1: Discount Rate 5%

Case 1: NPV Calculation Sheet

Year	Total Cost (MLKR)	Benefit due to Loss reduction (MLKR)	Net Benefit (MLKR)	Discounted Total (MLKR)	Cumulative Total (MLKR)
2025	13921.8	360.7	-13561.2	-13561	-13561
2026	137.8	849.2	711.3	677	-12884
2027	137.8	916.9	779.1	707	-12177
2028	137.8	1004.7	866.9	749	-11428
2029	137.8	1073.8	936.0	770	-10658
2030	137.8	1142.9	1005.1	788	-9871
2031	137.8	1271.2	1133.3	846	-9025
2032	137.8	1402.7	1264.9	899	-8126
2033	137.8	1542.0	1404.2	950	-7176
2034	137.8	1662.9	1525.1	983	-6193
2035	137.8	1783.8	1645.9	1010	-5182
2036	137.8	1904.6	1766.8	1033	-4149
2037	137.8	2025.4	1887.6	1051	-3098
2038	137.8	2146.3	2008.5	1065	-2033
2039	137.8	2267.1	2129.3	1075	-957
2040	137.8	2388.0	2250.2	1082	125
2041	137.8	2508.8	2371.0	1086	1211
2042	137.8	2629.7	2491.9	1087	2298
2043	137.8	2750.5	2612.7	1086	3384
2044	137.8	2871.4	2733.6	1082	4466
2045	137.8	2992.3	2854.4	1076	5542
2046	137.8	3113.1	2975.3	1068	6609
2047	137.8	3233.9	3096.1	1058	7668
2048	137.8	3354.8	3217.0	1047	8715
2049	137.8	3475.6	3337.8	1035	9750
2050	137.8	3596.5	3458.7	1021	10772
2051	137.8	3717.3	3579.5	1007	11778
2052	137.8	3838.2	3700.4	991	12769
2053	137.8	3959.0	3821.2	975	13744
2054	137.8	4079.9	3942.1	958	14702
2055	137.8	4200.8	4062.9	940	15642
				NPV	**15642**

Case 1: Benefit to Cost Ratio Calculation Sheet

Year	**Total Cost (MLKR)**	**Benefit due to Loss reduction (MLKR)**	**Discounted Benefit (B)**	**Discounted Investment (C)**
2025	13921.8	360.7	361	-13922
2026	137.8	849.2	809	-131
2027	137.8	916.9	832	-125
2028	137.8	1004.7	868	-119
2029	137.8	1073.8	883	-113
2030	137.8	1142.9	896	-108
2031	137.8	1271.2	949	-103
2032	137.8	1402.7	997	-98
2033	137.8	1542.0	1044	-93
2034	137.8	1662.9	1072	-89
2035	137.8	1783.8	1095	-85
2036	137.8	1904.6	1114	-81
2037	137.8	2025.4	1128	-77
2038	137.8	2146.3	1138	-73
2039	137.8	2267.1	1145	-70
2040	137.8	2388.0	1149	-66
2041	137.8	2508.8	1149	-63
2042	137.8	2629.7	1147	-60
2043	137.8	2750.5	1143	-57
2044	137.8	2871.4	1136	-55
2045	137.8	2992.3	1128	-52
2046	137.8	3113.1	1117	-49
2047	137.8	3233.9	1106	-47
2048	137.8	3354.8	1092	-45
2049	137.8	3475.6	1078	-43
2050	137.8	3596.5	1062	-41
2051	137.8	3717.3	1045	-39
2052	137.8	3838.2	1028	-37
2053	137.8	3959.0	1010	-35
2054	137.8	4079.9	991	-33
2055	137.8	4200.8	972	-32
			31683	-16041
			Benefit/Cost	**1.9751**

Case 2: 5% annual electricity cost increase

Case 2: EIRR Calculation Sheet

Year	Cost in (MLKR)			Benefit due to Loss reduction (MLKR)	Net Benefit (MLKR)
	Investment	Trans. O&M cost	Total Cost		
2025	13784	137.8	13921.8	378.7	-13543.1
2026		137.8	137.8	891.6	753.8
2027		137.8	137.8	962.8	824.9
2028		137.8	137.8	1055.0	917.1
2029		137.8	137.8	1127.5	989.7
2030		137.8	137.8	1200.1	1062.2
2031		137.8	137.8	1334.7	1196.9
2032		137.8	137.8	1472.8	1335.0
2033		137.8	137.8	1619.2	1481.3
2034		137.8	137.8	1746.0	1608.2
2035		137.8	137.8	1872.9	1735.1
2036		137.8	137.8	1999.8	1862.0
2037		137.8	137.8	2126.7	1988.9
2038		137.8	137.8	2253.6	2115.8
2039		137.8	137.8	2380.5	2242.7
2040		137.8	137.8	2507.4	2369.6
2041		137.8	137.8	2634.3	2496.5
2042		137.8	137.8	2761.2	2623.3
2043		137.8	137.8	2888.1	2750.2
2044		137.8	137.8	3015.0	2877.1
2045		137.8	137.8	3141.9	3004.0
2046		137.8	137.8	3268.8	3130.9
2047		137.8	137.8	3395.6	3257.8
2048		137.8	137.8	3522.5	3384.7
2049		137.8	137.8	3649.4	3511.6
2050		137.8	137.8	3776.3	3638.5
2051		137.8	137.8	3903.2	3765.4
2052		137.8	137.8	4030.1	3892.3
2053		137.8	137.8	4157.0	4019.2
2054		137.8	137.8	4283.9	4146.1
2055		137.8	137.8	4410.8	4272.9
				EIRR	**11.2%**

Case 2: NPV Calculation Sheet

Year	Total Cost (MLKR)	Benefit due to Loss reduction (MLKR)	Net Benefit (MLKR)	Discounted Total (MLKR)	Cumulative Total (MLKR)
2025	13921.8	378.7	-13543.1	-13543	-13543
2026	137.8	891.6	753.8	685	-12858
2027	137.8	962.8	824.9	682	-12176
2028	137.8	1055.0	917.1	689	-11487
2029	137.8	1127.5	989.7	676	-10811
2030	137.8	1200.1	1062.2	660	-10152
2031	137.8	1334.7	1196.9	676	-9476
2032	137.8	1472.8	1335.0	685	-8791
2033	137.8	1619.2	1481.3	691	-8100
2034	137.8	1746.0	1608.2	682	-7418
2035	137.8	1872.9	1735.1	669	-6749
2036	137.8	1999.8	1862.0	653	-6096
2037	137.8	2126.7	1988.9	634	-5462
2038	137.8	2253.6	2115.8	613	-4850
2039	137.8	2380.5	2242.7	591	-4259
2040	137.8	2507.4	2369.6	567	-3692
2041	137.8	2634.3	2496.5	543	-3148
2042	137.8	2761.2	2623.3	519	-2629
2043	137.8	2888.1	2750.2	495	-2135
2044	137.8	3015.0	2877.1	470	-1664
2045	137.8	3141.9	3004.0	447	-1218
2046	137.8	3268.8	3130.9	423	-795
2047	137.8	3395.6	3257.8	400	-395
2048	137.8	3522.5	3384.7	378	-17
2049	137.8	3649.4	3511.6	357	340
2050	137.8	3776.3	3638.5	336	676
2051	137.8	3903.2	3765.4	316	992
2052	137.8	4030.1	3892.3	297	1289
2053	137.8	4157.0	4019.2	279	1567
2054	137.8	4283.9	4146.1	261	1829
2055	137.8	4410.8	4272.9	245	2074
				NPV	**2074**

Case 2: Benefit to Cost Ratio Calculation Sheet

Year	Total Cost (MLKR)	Benefit due to Loss reduction (MLKR)	Discounted Benefit (B)	Discounted Investment (C)
2025	13921.8	-13543.1	379	-13922
2026	137.8	753.8	811	-125
2027	137.8	824.9	796	-114
2028	137.8	917.1	793	-104
2029	137.8	989.7	770	-94
2030	137.8	1062.2	745	-86
2031	137.8	1196.9	753	-78
2032	137.8	1335.0	756	-71
2033	137.8	1481.3	755	-64
2034	137.8	1608.2	740	-58
2035	137.8	1735.1	722	-53
2036	137.8	1862.0	701	-48
2037	137.8	1988.9	678	-44
2038	137.8	2115.8	653	-40
2039	137.8	2242.7	627	-36
2040	137.8	2369.6	600	-33
2041	137.8	2496.5	573	-30
2042	137.8	2623.3	546	-27
2043	137.8	2750.2	519	-25
2044	137.8	2877.1	493	-23
2045	137.8	3004.0	467	-20
2046	137.8	3130.9	442	-19
2047	137.8	3257.8	417	-17
2048	137.8	3384.7	393	-15
2049	137.8	3511.6	371	-14
2050	137.8	3638.5	349	-13
2051	137.8	3765.4	328	-12
2052	137.8	3892.3	307	-11
2053	137.8	4019.2	288	-10
2054	137.8	4146.1	270	-9
2055	137.8	4272.9	253	-8
			17295	-15221
			Benefit/Cost	**1.1362**

Case 3: 2% Transmission O&M cost percentage

Case 3: EIRR Calculation Sheet

Year	Cost in (MLKR)			Benefit due to Loss reduction (MLKR)	Net Benefit (MLKR)
	Investment	Trans. O&M cost	Total Cost		
2025	13784	275.7	14059.7	360.7	-13699.0
2026		275.7	275.7	849.2	573.5
2027		275.7	275.7	916.9	641.2
2028		275.7	275.7	1004.7	729.0
2029		275.7	275.7	1073.8	798.1
2030		275.7	275.7	1142.9	867.3
2031		275.7	275.7	1271.2	995.5
2032		275.7	275.7	1402.7	1127.0
2033		275.7	275.7	1542.0	1266.4
2034		275.7	275.7	1662.9	1387.2
2035		275.7	275.7	1783.8	1508.1
2036		275.7	275.7	1904.6	1628.9
2037		275.7	275.7	2025.4	1749.8
2038		275.7	275.7	2146.3	1870.6
2039		275.7	275.7	2267.1	1991.5
2040		275.7	275.7	2388.0	2112.3
2041		275.7	275.7	2508.8	2233.2
2042		275.7	275.7	2629.7	2354.0
2043		275.7	275.7	2750.5	2474.9
2044		275.7	275.7	2871.4	2595.7
2045		275.7	275.7	2992.3	2716.6
2046		275.7	275.7	3113.1	2837.4
2047		275.7	275.7	3233.9	2958.3
2048		275.7	275.7	3354.8	3079.1
2049		275.7	275.7	3475.6	3200.0
2050		275.7	275.7	3596.5	3320.8
2051		275.7	275.7	3717.3	3441.7
2052		275.7	275.7	3838.2	3562.5
2053		275.7	275.7	3959.0	3683.4
2054		275.7	275.7	4079.9	3804.2
2055		275.7	275.7	4200.8	3925.1
				EIRR	**9.9%**

Case 3: NPV Calculation Sheet

Year	Total Cost (MLKR)	Benefit due to Loss reduction (MLKR)	Net Benefit (MLKR)	Discounted Total (MLKR)	Cumulative Total (MLKR)
2025	14059.7	360.7	-13699.0	-13699	-13699
2026	275.7	849.2	573.5	521	-13178
2027	275.7	916.9	641.2	530	-12648
2028	275.7	1004.7	729.0	548	-12100
2029	275.7	1073.8	798.1	545	-11555
2030	275.7	1142.9	867.3	538	-11016
2031	275.7	1271.2	995.5	562	-10454
2032	275.7	1402.7	1127.0	578	-9876
2033	275.7	1542.0	1266.4	591	-9285
2034	275.7	1662.9	1387.2	588	-8697
2035	275.7	1783.8	1508.1	581	-8116
2036	275.7	1904.6	1628.9	571	-7545
2037	275.7	2025.4	1749.8	558	-6987
2038	275.7	2146.3	1870.6	542	-6445
2039	275.7	2267.1	1991.5	524	-5921
2040	275.7	2388.0	2112.3	506	-5415
2041	275.7	2508.8	2233.2	486	-4929
2042	275.7	2629.7	2354.0	466	-4463
2043	275.7	2750.5	2474.9	445	-4018
2044	275.7	2871.4	2595.7	424	-3594
2045	275.7	2992.3	2716.6	404	-3190
2046	275.7	3113.1	2837.4	383	-2807
2047	275.7	3233.9	2958.3	363	-2443
2048	275.7	3354.8	3079.1	344	-2099
2049	275.7	3475.6	3200.0	325	-1774
2050	275.7	3596.5	3320.8	306	-1468
2051	275.7	3717.3	3441.7	289	-1179
2052	275.7	3838.2	3562.5	272	-907
2053	275.7	3959.0	3683.4	255	-652
2054	275.7	4079.9	3804.2	240	-412
2055	275.7	4200.8	3925.1	225	-187
				NPV	**-187**

Case 3: Benefit to Cost Ratio Calculation Sheet

Year	Total Cost (MLKR)	Benefit due to Loss reduction (MLKR)	Discounted Benefit (B)	Discounted Investment (C)
2025	14059.7	360.7	361	-14060
2026	275.7	849.2	772	-251
2027	275.7	916.9	758	-228
2028	275.7	1004.7	755	-207
2029	275.7	1073.8	733	-188
2030	275.7	1142.9	710	-171
2031	275.7	1271.2	718	-156
2032	275.7	1402.7	720	-141
2033	275.7	1542.0	719	-129
2034	275.7	1662.9	705	-117
2035	275.7	1783.8	688	-106
2036	275.7	1904.6	668	-97
2037	275.7	2025.4	645	-88
2038	275.7	2146.3	622	-80
2039	275.7	2267.1	597	-73
2040	275.7	2388.0	572	-66
2041	275.7	2508.8	546	-60
2042	275.7	2629.7	520	-55
2043	275.7	2750.5	495	-50
2044	275.7	2871.4	469	-45
2045	275.7	2992.3	445	-41
2046	275.7	3113.1	421	-37
2047	275.7	3233.9	397	-34
2048	275.7	3354.8	375	-31
2049	275.7	3475.6	353	-28
2050	275.7	3596.5	332	-25
2051	275.7	3717.3	312	-23
2052	275.7	3838.2	293	-21
2053	275.7	3959.0	275	-19
2054	275.7	4079.9	257	-17
2055	275.7	4200.8	241	-16
			16471	-16658
			Benefit/Cost	**0.9888**

Case 4: Taking generation energy unit cost as 10.73 LKR/kWh and average generation capacity cost as 1.2 MLKR/MW

Case 4: EIRR Calculation Sheet

Year	Cost in (MLKR)			Benefit due to Loss reduction (MLKR)	Net Benefit (MLKR)
	Investment	Trans. O&M cost	Total Cost		
2025	13784	137.8	13921.8	200.0	-13721.8
2026		137.8	137.8	471.1	333.2
2027		137.8	137.8	508.6	370.8
2028		137.8	137.8	557.0	419.2
2029		137.8	137.8	595.3	457.5
2030		137.8	137.8	633.6	495.8
2031		137.8	137.8	704.8	566.9
2032		137.8	137.8	777.7	639.9
2033		137.8	137.8	857.0	719.1
2034		137.8	137.8	923.9	786.1
2035		137.8	137.8	990.9	853.1
2036		137.8	137.8	1057.9	920.0
2037		137.8	137.8	1124.9	987.0
2038		137.8	137.8	1191.8	1054.0
2039		137.8	137.8	1258.8	1121.0
2040		137.8	137.8	1325.8	1187.9
2041		137.8	137.8	1392.7	1254.9
2042		137.8	137.8	1459.7	1321.9
2043		137.8	137.8	1526.7	1388.8
2044		137.8	137.8	1593.6	1455.8
2045		137.8	137.8	1660.6	1522.8
2046		137.8	137.8	1727.6	1589.7
2047		137.8	137.8	1794.5	1656.7
2048		137.8	137.8	1861.5	1723.7
2049		137.8	137.8	1928.5	1790.6
2050		137.8	137.8	1995.4	1857.6
2051		137.8	137.8	2062.4	1924.6
2052		137.8	137.8	2129.4	1991.5
2053		137.8	137.8	2196.4	2058.5
2054		137.8	137.8	2263.3	2125.5
2055		137.8	137.8	2330.3	2192.5
				EIRR	**5.7%**

Case 4: NPV Calculation Sheet

Year	Total Cost (MLKR)	Benefit due to Loss reduction (MLKR)	Net Benefit (MLKR)	Discounted Total (MLKR)	Cumulative Total (MLKR)
2025	13921.8	200.0	-13721.8	-13722	-13722
2026	137.8	471.1	333.2	303	-13419
2027	137.8	508.6	370.8	306	-13112
2028	137.8	557.0	419.2	315	-12798
2029	137.8	595.3	457.5	312	-12485
2030	137.8	633.6	495.8	308	-12177
2031	137.8	704.8	566.9	320	-11857
2032	137.8	777.7	639.9	328	-11529
2033	137.8	857.0	719.1	335	-11193
2034	137.8	923.9	786.1	333	-10860
2035	137.8	990.9	853.1	329	-10531
2036	137.8	1057.9	920.0	322	-10209
2037	137.8	1124.9	987.0	314	-9894
2038	137.8	1191.8	1054.0	305	-9589
2039	137.8	1258.8	1121.0	295	-9294
2040	137.8	1325.8	1187.9	284	-9009
2041	137.8	1392.7	1254.9	273	-8736
2042	137.8	1459.7	1321.9	262	-8475
2043	137.8	1526.7	1388.8	250	-8225
2044	137.8	1593.6	1455.8	238	-7987
2045	137.8	1660.6	1522.8	226	-7760
2046	137.8	1727.6	1589.7	215	-7546
2047	137.8	1794.5	1656.7	204	-7342
2048	137.8	1861.5	1723.7	192	-7150
2049	137.8	1928.5	1790.6	182	-6968
2050	137.8	1995.4	1857.6	171	-6796
2051	137.8	2062.4	1924.6	161	-6635
2052	137.8	2129.4	1991.5	152	-6483
2053	137.8	2196.4	2058.5	143	-6340
2054	137.8	2263.3	2125.5	134	-6206
2055	137.8	2330.3	2192.5	126	-6081
				NPV	**-6081**

Case 4: Benefit to Cost Ratio Calculation Sheet

Year	Total Cost (MLKR)	Benefit due to Loss reduction (MLKR)	Discounted Benefit (B)	Discounted Investment (C)
2025	13921.8	200.0	200	-13922
2026	137.8	471.1	428	-125
2027	137.8	508.6	420	-114
2028	137.8	557.0	418	-104
2029	137.8	595.3	407	-94
2030	137.8	633.6	393	-86
2031	137.8	704.8	398	-78
2032	137.8	777.7	399	-71
2033	137.8	857.0	400	-64
2034	137.8	923.9	392	-58
2035	137.8	990.9	382	-53
2036	137.8	1057.9	371	-48
2037	137.8	1124.9	358	-44
2038	137.8	1191.8	345	-40
2039	137.8	1258.8	331	-36
2040	137.8	1325.8	317	-33
2041	137.8	1392.7	303	-30
2042	137.8	1459.7	289	-27
2043	137.8	1526.7	275	-25
2044	137.8	1593.6	261	-23
2045	137.8	1660.6	247	-20
2046	137.8	1727.6	233	-19
2047	137.8	1794.5	220	-17
2048	137.8	1861.5	208	-15
2049	137.8	1928.5	196	-14
2050	137.8	1995.4	184	-13
2051	137.8	2062.4	173	-12
2052	137.8	2129.4	162	-11
2053	137.8	2196.4	152	-10
2054	137.8	2263.3	143	-9
2055	137.8	2330.3	134	-8
			9141	-15221
			Benefit/Cost	**0.6005**