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Harmonic Allocation to Major Loads in Transmission Systems

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Abstract

A few decades ago, harmonic levels in electricity transmission networks were relatively low due to limited harmonic loads (such as renewable generation), low emissions from bulk supply points, high levels of synchronous generation and absorption from connected loads. Various international publications have forecasted that by 2030 many power systems around the world would have as high as 30% of renewable generation, e.g. solar and wind plants, which produce significant harmonics, and more than 60% increase in other harmonic producing loads (industrial, farming and residential equipment). This is coupled with the expected retirement of a large number of fossil-fuelled synchronous generators. Accordingly, growth in harmonic levels in the transmission network is anticipated.

The Australian power system landscape has already changed and will continue to move rapidly towards having more renewable energy sources and power electronic loads. Recently, state governments throughout Australia have confirmed their support for the development of Renewable Energy Zones (REZ), i.e. areas with high concentrations of renewable energy sources. In August 2020, the Australian Energy Market Operator (AEMO) published the Integrated System Plan (ISP), which provides a 20-year roadmap for the National Electricity Market (NEM) through the energy transition period to 2040. The ISP includes a 63% reduction in coal-fired synchronous generation, a 200% increase in Distributed Energy Resources and a 75% increase in solar and wind plants. These new technologies bring with them a wide range of harmonic issues; however, there has been no significant updates in the harmonic management of Australian transmission systems. In particular, the latest version of the Australian National Electricity Rules (NER), as of 17 September 2020, still referenced the 20 years old Australian and New Zealand Standard, i.e. AS/NZS 61000.3.6:2001. Transmission System Operators (TSOs) rely heavily on existing standards and guidelines, which have increasingly become less relevant and less effective for modern power systems. Urgent review and improvement of existing standards and guidelines are needed to avoid unnecessary impediment to the transition plan of power systems towards modern loads and higher renewable penetration platforms.

This thesis will focus on key deliverables that will help TSOs to better manage harmonic allocation to loads in current and future transmission systems, including: (i) develop an in-depth understanding of the complexities of transmission network harmonic impedances affecting harmonic allocation and harmonic management; (ii) develop a new harmonic allocation method that can utilise network absorption capability more effectively and distribute it fairly and equally to all network participants; (iii) evaluate the practical application of existing and new harmonic allocation methods and recommend the most suitable method for transmission systems; (iv) apply the recommended harmonic allocation method to renewable generators and recommend practical options to enhance allocation to renewable harmonic sources; (v) design a new harmonic planning and management framework to guide detailed connection enquiry procedures and optimise an allocation approach to best suit specific requirements, e.g. harmonic profiles, of different types of harmonic sources; and finally, (vi) recommend updates to the NER to include harmonic planning for Renewable Energy Zones and introduce Power Quality Ancillary Services to support the ISP published by AEMO.

There seems to be a disconnection between existing harmonic standards and how modern technologies have exponentially penetrated power systems around the world over the last 20 years. The underlying principles and assumptions have been challenged and their practical applications have become less effective. This thesis focuses on maximising the utilisation of network harmonic absorption and attenuation capabilities to safely allocate global harmonic contributions to all customer connections so that the network can accommodate more harmonic sources without causing adverse harmonic issues.

In contrast with a distribution network, harmonic impedances within a transmission network are complex and often difficult to accurately predict or simplify at higher-order harmonics due to the interactions between capacitive and inductive components. Different mixes of network elements, e.g. transmission lines, transformers, generators, capacitor banks and loads at different connection points, result in a wide range of network impedances that directly affect harmonic allocation. Transmission systems also have a large number of network scenarios that require detailed and sophisticated network models to study. This thesis will develop a new strategic harmonic planning and management framework to support the practical application of a new harmonic allocation method mentioned above for transmission systems. This framework includes a comprehensive list of recommendations, allocation procedures, integrated harmonic planning as part of the network Strategic Asset Management Plan, and an optimised allocation method to best suit profiles of harmonic sources.

Power systems in Australia have already experienced higher penetration of new harmonic sources from consumer loads, network equipment and renewable generators. There is mounting evidence that the network harmonic absorption capability will eventually run out, resulting in the maximum permitted harmonic limits being reached. In this regard, the NER needs to be updated to ensure that the power system will still function as intended and deliver affordable services to all network participants. This thesis proposes a process for harmonic planning for Renewable Energy Zones and Power Quality Ancillary Services to support and maintain power quality services in transmission systems with high penetration levels of harmonic sources.

To ensure an evidence-based approach, several practical case studies have been conducted to demonstrate the effectiveness of the new harmonic management methodologies referred to above. These case studies include the identification of the key indicators for the harmonic performance of a realistic transmission system.

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Certification

I, Tuan Vu, declare that this thesis submitted in fulfilment of the requirements for the conferral of the degree Doctor of Philosophy, from the University of Wollongong, is wholly my work unless otherwise referenced or acknowledged. This document has not been submitted for qualifications at any other academic institution.

Tuan Vu
18 December 2020

List of Names or Abbreviations

AEMO	Australian Energy Market Operator
AEMC	Australian Energy Market Commission
AC	Alternating Current
C&AA	Connection and Access Agreement
CIGRE	French acronym, standing for Conseil International des Grands Réseaux Electriques; this translates as Council on Large Electric Systems
CIRED	Centre International de Recherche sur l'Environnement et le Développement (French: International Agency for Research on the Environment and Development)
DC	Direct Current
DER	Distributed Energy Resource
DNSP	Distribution Network Service Provider
DSO	Distribution System Operator
E_{Ihi}	Harmonic Current Allocation to load i (S_i) at harmonic order h
E_{Uhi}	Harmonic Voltage Allocation to load i (S_i) at harmonic order h
EHV	Extra High Voltage
EMC	Electromagnetic Compatibility
emf	Electromotive Force
EMF	Electromagnetic Fields
ENA	Energy Networks Australia
ESAA	Energy Supply Association of Australia
FACTS	Flexible AC Transmission Systems
FCAS	Frequency Control Ancillary Services

$F_{RMS\text{-}NA}(a)$	Root Mean Square Normalised Allocation Factor of network scenario a, i.e. sum of the square of allocation divided by respective planning levels
F_{Max}	The maximum value of $F_{RMS\text{-}NA}(a)$ from all network scenarios
$G_m(h)$	Maximum global contribution to the h^{th} harmonic voltage of all distorting loads that can be connected at bus m
GATT	General Agreement on Tariffs and Trade
GTO	Gate-Turn-Off thyristor
HV	High Voltage
HVDC	High Voltage Direct Current
IEC	International Electro-technical Commission
IEEE	Institute of Electrical and Electronics Engineers
I_L	Maximum demand load current (fundamental frequency component) at the PCC under normal load operating conditions
I_{SC}	Maximum short-circuit current at PCC
IGBT	Insulated Gate Bipolar Transistor
$L_{HV\text{-}EHV}(h)$	Planning level at harmonic order h
LV	Low Voltage
MV	Medium Voltage
NEM	National Electricity Market
NER	Australian National Electricity Rules
OOS	Out Of Service
PCC	Point of Common Coupling
PQAS	Power Quality Ancillary Services
PWM	Pulse-Width Modulation

$Q_{F\_11}(\%)$	Harmonic Profile Tolerance for Load 11
$Q_{F\_12}(\%)$	Harmonic Profile Tolerance for Load 12
$Q_{F\_FMAX\_11}(\%)$	Tolerance of F_{Max} (Maximum RMS Normalised Allocation Factor) for Load 11
$Q_{F\_FMAX\_11}(\%)$	Tolerance of F_{Max} (Maximum RMS Normalised Allocation Factor) for Load 12
$Q_{F\_FMAx\_i}$	Optimised Allocation Factor for load i
Q_{F_i}	Optimised Allocation Factor for load i
RES	Renewable Energy Resources
REZ	Renewable Energy Zones
RMS, rms	Root Mean Square
RP	Renewable Proponent
S_{Din}	Existing IEC technical report terminology – The power of any HVDC stations or non-linear generating plants
S_{Dshunt}	Existing IEC technical report terminology – The dynamic rating of any thyristor-controlled reactor (TCR) of any static VAr compensators connected at the busbar under consideration
S_i	Existing IEC technical report terminology – Agreed Power of the load S_i
S_{out}	Existing IEC technical report terminology – Power flowing out of the considered HV-EHV busbar, including provision for future load growth
S_t	Existing IEC technical report terminology – An approximation of the total power of all installations for which emission limits are to be allocated in the foreseeable future
S_{tm}	Existing IEC technical report terminology – Total supply capacity at node m
S_{tS}	New (proposed) terminology for total supply capacity
S_{1S}, S_{2S},.., S_{nS}	Planned Unused Spare Capacity for Sharing at bus 1, bus 2, …, bus n
$S_{Existing\_Loads\_j}$	Existing load j
$S_{Export\_Power\_y}$	Export Power y

S_{Gen_i}:	Generation Power *i*
$S_{Import\_Power\_x}$	Import Power *x*
S_{Loads_ma}	Total number of Load *a* to be connected, consists of existing and new loads being considered for connection, to bus *m* at the time of assessment
S_{mFL}	Spare Supply Capacity Reserved for future loads
S_{mR}	Spare Supply Capacity Reserved for a safety margin
S_{mS}	Unused Spare Supply Capacity that is planned for sharing to allow higher harmonic emissions among buses
S_{Spare_m}	Total Spare Capacity at substation *m* at the time of assessment
S_{tS1}, S_{tS2},..,S_{tSn}	Total Spare Supply Capacity at bus 1, bus 2, …, bus *n*
S_{tSm}	Total Supply Capacity at bus *m* (any arbitrary bus of the *n* bus system)
SAMP	Strategic Asset Management Plan
SCP	Short Circuit Power
SCR	Short Circuit Ratio
VSC	Voltage Source Converter
STATCOM	Static Compensator
SVC	Static VAr Compensator
TCR	Thyristor Control Reactor
TSC	Thyristor Switch Capacitor
TNSP	Transmission Network Service Provider
TSO	Transmission Service Operator
VCAS	Voltage Control Ancillary Services
VRE	Variable Renewable Energy – Wind and Solar

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1 Thesis Overview

1.1 Statement of the Problem

Harmonics have always existed in power systems and presented many issues for electricity utilities, equipment manufacturers and electricity consumers [1]. Excessive harmonic currents and voltages can cause issues such as additional losses, overheating, equipment malfunction, low power factors, control system mal-functions and system instability [2]. The main factors influencing harmonics in power systems are generation equipment, end-user equipment and the grid itself [3]. In the past, power system harmonics were predominantly caused by characteristics of equipment having saturable magnetic cores or early generation non-linear power electronic loads, where the level of resulting harmonics was relatively low [4] compared with the supply capacity and the absorption capability of the network. Nowadays, in addition to traditional harmonic sources, new harmonic sources such as solar and wind power plants, battery storage systems, SVCs and STATCOMs, have rapidly penetrated the power system due to declining costs, flexible applications and better control [5]. As a result, harmonic related issues have become more noticeable coupled with large variations in the harmonic spectra associated with power electronic-based technologies at all levels of power systems – generation, network and consumer loads [6]. This trend has exacerbated issues even further and created more challenges for utilities to manage harmonics in their networks [7]. These issues, if not managed effectively, could potentially lead to widespread equipment failures, system malfunction, supply reliability and availability issues, and significant financial losses to all network participants and consumers.

It is necessary to acknowledge that, in many parts of the world, power systems have already started to experience a significant increase in harmonics from power electronic converters coupled with a reduction of harmonic absorption capability from synchronous generators. Without careful planning, such networks will become much more susceptible to higher harmonic emissions and transfer of disturbances [8]. It will be much harder for network operators to manage harmonics, while ensuring that relevant code compliance, For example, the Australian National Electricity Rules require harmonic compatibility levels, planning levels and emission levels to be set in alignment with AS/NZS 61000.3.6:2001 [9] (a previous version of the IEC guidelines [10]) as a requirement for all customer connections.

The CIRED/CIGRE Joint Working Group, following the IEC terminology, distinguishes between "disturbances" (any deviation from the ideal sinusoidal voltage or current) and "interference" (damage or malfunction of end-user-equipment) [11]. Ultimately, what really matters is the compatibility among different equipment, systems and the grid [3]. Equipment connected to the power system must be able to withstand harmonic distortion (disturbances of voltages and currents) in the network. Equipment immunity levels for electrical equipment are set by relevant equipment design and manufacturing standards [12]. It is expected that equipment is designed and tested according to these standards to ensure immunity to harmonic distortion at least up to the compatibility levels, which are the absolute maximum harmonic distortion levels that should ever be allowed in the network. Most equipments are connected to LV and MV networks, hence compatibility levels were set for LV and MV by IEC 61000.2.2 [13] and

IEC 61000.2.12 [14] as hard limits, and, e.g. AS/NZS 61000.2.12 [15] for coordinating the emission and immunity of equipment. However, for HV and Extra High Voltage (EHV), there are no compatibility levels, but indicative planning levels are referenced in the IEC 61000.3.6 [10] technical report.

In practice, planning levels, also referred to as network harmonic limits, must be set equal to or lower than the compatibility levels, and are typically assigned depending on network voltage levels. Distribution and Transmission Network Service Providers (DNSPs and TNSPs) are tasked to set harmonic limits for their networks and allocate emission levels to harmonic sources to ensure that equipment connected to their network are not adversely affected. It is not practical to have different planning levels, set by different network service providers, across different areas of an interconnected transmission system (like the eastern states in Australia). Since the introduction of the National Electricity Rules (NER) most transmission utilities in Australia, if not all, have gradually adopted the recommended planning levels in IEC standard.

Network utilities also need to ensure that all network participants are allocated harmonic levels equitably and not inadvertently disadvantaged. Therefore, it is important that relevant harmonic standards, regulatory codes and application guides are available to provide a uniform approach for the management of harmonics. Despite the existence of these avenues and significant efforts to improve their effectiveness in application to date, the practical application of these standards and guidelines for harmonic allocation to loads in transmission systems still often results in deficiencies. Such deficiencies include under-allocation due to network absorption capacity being under-utilised, and over-allocation because of inaccurate estimation of future loads and unrealistic network scenarios. Under-allocation restricts harmonic emissions unnecessarily and may incur additional connection or mitigation costs to owners of harmonic sources. On the other hand, over-allocation may cause harmonics to exceed planning levels, requiring utilities to modify the network or install harmonic filters to mitigate excessive harmonics. Either scenario will result in extra costs to network participants, network infrastructure and ultimately higher electricity prices for consumers. This research project has identified several complexities associated with transmission systems and deficiencies associated with the existing standards [9, 10, 16] that need to be overcome to achieve better harmonic allocation for major loads in transmission systems.

In practice, the application of harmonic allocation to major loads in transmission systems often involves consideration of many network scenarios, ranging from a few hundred to some thousands of network cases [17]. It would require the aid of computing resources and complex algorithms to process all network scenarios. A number of allocation related questions investigated in this thesis include: (i) can the number of network scenarios be reduced to ease harmonic allocation in transmission systems, and how? (ii) what are the impacts of changes in network scenarios on harmonic allocation? (iii) how can allocations be optimised, from large numbers of network scenarios, to suit specific requirements, e.g. harmonic profiles, of different harmonic sources.

Electricity consumers and network participants demand service quality, such as supply reliability, availability, affordability, efficiency and security, as well as environmental and energy sustainability [8]. Without long-term investment in large baseload thermal and hydro generators, alternative generation sources such as wind, solar and battery plants (all rely on power electronic converter interfaces to the grid) are likely to become the main generating sources of future power systems. This means that service quality will be achieved by increasing the integration of new and advanced technologies in power systems, including renewable energy sources (RES), distributed energy resources (DER) and the latest available power electronic-based equipment [18]. These new technologies bring with them a wide range of harmonics and related challenges that have not yet been fully appreciated where the emerging issues must be thoroughly investigated, understood and managed holistically. In particular, there is still a lack of recommended practices for harmonic management in networks with high penetration levels of renewable sources [19]. The current approach is based on fundamentals of conventional power systems, in which synchronous rotating generators have the ability to absorb harmonics and flow of harmonics (from "sources") to these generators (or other harmonic "sinks"), with loads and other power system equipment providing some attenuation along the way. However, this assumption has not been revisited concerning modern power systems that have renewable generation sources, e.g. solar and wind plants. These plants produce harmonics and are unable to absorb the same level of harmonics and/or contribute to harmonic attenuation [1-7]. For this reason, harmonic filters are often installed within the wind and solar plants to comply with connection rules to reduce emissions related to specific harmonics. These filters also absorb harmonics from the network, and need to be designed to cater for such interactions, but generally mitigate only the effects of the local converter emissions. While transmission lines and capacitors may contribute to harmonic resonance conditions, passive harmonic filters may also increase the chances of resonances within a network at other frequencies. Therefore, additional considerations are required for harmonic management in modern networks which have high penetration levels of renewable generation sources.

An overarching harmonic management strategy is also required to integrate processes and harmonise requirements between harmonic allocation methods, optimised number of network scenarios, and recommend harmonic management practices for networks with high penetration of renewable generation sources.

1.2 Research Objectives and Methodologies

Network utilities rely on standards and guidelines to set network harmonic planning limits, allocate emission levels to loads, and assess and monitor compliance at all relevant buses in their networks. This research project aims to develop a comprehensive harmonic allocation strategy, aligning with the general philosophy of the latest IEC technical report (IEC/TR 61000-3-6.Ed. 2: 2008 – adopted by Standards Australia as AS/NZS IEC/TR 61000-3-6.Ed. 2: 2008 in 2012) for major loads in transmission systems based on equitable, practical and best engineering practices. The underlying principle of this strategy is to maximise the utilisation of network harmonic absorption capability while ensuring compliance with planning limits. The harmonic allocation strategy will be evaluated based on its effectiveness and practical application to allocate emission levels to major harmonic sources in transmission systems, including networks with high renewable generation penetration levels. The discussion of harmonic allocation cannot avoid reference to compliance assessment, however, it will not be exhaustively examined in this thesis. In this thesis, pre-connection compliance against planning levels is used as a criterion for assessing the effectiveness of harmonic allocation methods. Treatment of post-connection compliance, studies of inter-harmonics and intra-harmonics beyond 25^{th} harmonic, and detailed harmonic modelling are not in the scope of this thesis.

The major research objectives and methodologies of this thesis consist of a number of key deliverables:

(i) A brief review of existing and new harmonic sources and harmonic models, computation of complex impedances in transmission systems, and existing harmonic allocation methodologies;

(ii) Identify deficiencies and challenges associated with existing harmonic allocation methodologies;

(iii) Develop an in-depth understanding of, and examine, the complexities of transmission network impedances, coupled with a large number of network scenarios, affecting harmonic allocation;

(iv) Derive a new harmonic allocation method, e.g. amendments to the existing IEC allocation method, to improve harmonic allocation to loads in transmission systems;

(v) Recommend methodologies to optimise harmonic allocations, from large numbers of network scenarios, to suit specific requirements of different types and profiles of harmonic sources;

(vi) Evaluate the practical application of harmonic allocation methods, including the new method stated above; and recommend the most effective and practical method for transmission systems;

(vii) Examine the practical application of the new harmonic allocation method to renewable generators and recommend considerations for improvement options for transmission systems with high penetration levels of renewable generation sources, e.g. solar and wind power plants;

(viii) Develop a Strategic Harmonic Planning and Management Framework for Transmission Systems incorporating the new allocation method and recommendations stated above for harmonic allocation to major loads in transmission systems.

1.3 Thesis Outline

A summary of the contributions of each of the remaining chapters of this thesis is detailed below and schematically illustrated in Figure 1.1.

Chapter 2 provides a literature review of harmonics in power systems (sources, network and equipment impact, and modelling) and key aspects of harmonic management in transmission systems. The review focuses on two main streams of work. First stream: a review of harmonics associated with harmonic sources (emission of power quality disturbances) and network (transfer and absorption of disturbances). Second stream: detailed examination of existing international harmonic standards and guidelines that apply to harmonic management in Australia. These include IEEE-519 [16], IEC 61000-3-6. Ed. 2:2008 [10] and associated versions, AS 2279.2 [20], Energy Network Australia guidelines [21], Energy Supply Association of Australia (ESAA) method or utility common practices (e.g. one-third planning level method), National

Electricity Rules (NER) [19], and requirements from AEMO for harmonic management and planning in transmission systems [18].

Chapter 3 identifies deficiencies associated with the existing IEC technical report [10] on harmonic allocation method for transmission systems. A realistic transmission network with 7 buses is modelled based on the CIGRE guideline [22] and computation methods of [23] are used to help identify the issues outlined in Section 1.1.

Chapter 4 identifies the complexities of transmission network impedances that are coupled with a very large number of network scenarios. These issues, together with harmonic allocation deficiencies discussed in Chapter 3, present compounded challenges to the practical application of harmonic allocation to loads in transmission systems.

Chapter 5 derives a new allocation method to overcome deficiencies of the IEC method identified in Chapter 3. The method remains based on the IEC approach but includes several recommended amendments to improve useability and effectiveness, which is interpreted in this thesis as the ability to maximise harmonic allocation to loads while ensuring emission levels are compliant with planning levels as referenced under the existing method.

Chapter 6 evaluates the practical application of harmonic allocation methods, including the new method derived in Chapter 5, and recommends the most suitable and effective allocation method for loads in transmission systems.

Chapter 7 applies the new harmonic allocation recommended in Chapter 6, to allocate harmonics to renewable generation sources in transmission systems. Several practical improvements are also examined to maximise allocations to renewable generators in transmission systems while ensuring equitability to all network participants.

Chapter 8 develops a Strategic Harmonic Planning and Management Framework for Transmission Systems. This framework combines the understanding of harmonic issues in transmission systems identified in Chapters 3 & 4, the new allocation method in Chapters 5 & 6, lessons learnt and improvement options in Chapter 7 to form an integrated harmonic management strategy for transmission systems. It focuses on three key initiatives: (i) strategic management workflow, including strategic network area planning and detailed allocation procedure; (ii) optimised harmonic allocation for large network scenarios; and (iii) harmonic planning for Renewable Energy Zones.

Chapter 9 summarises significant findings from this thesis and recommends future work.

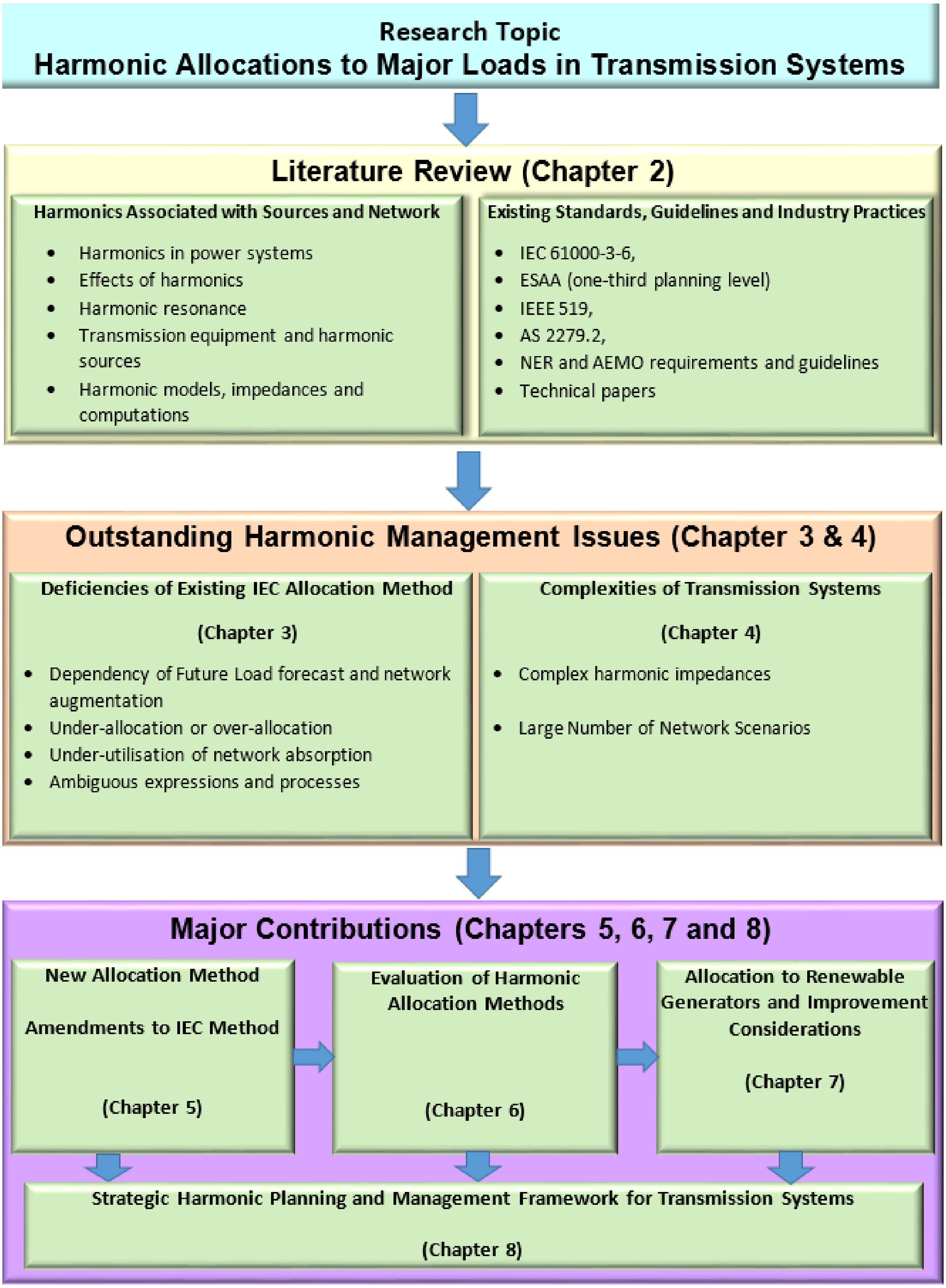


Figure 1.1 - Graphical representation of work undertaken in the thesis

2 Literature Review

2.1 Harmonics in Power Systems

Harmonics have existed since the formation of power systems [2]. Harmonics originate from various sources such as generators, power electronic equipment, or non-linear loads. Synchronously rotating generators, which normally produce sinusoidal voltages and currents, will also generate harmonics if they are connected to an unbalanced network [1]. In modern power systems, significant harmonic sources include power electronic conditioning and conversion equipment used in renewable generation (solar and wind plants) and battery storage. Such power electronic equipment, have been extensively installed in transmission and distribution networks, industry, and residential premises. Relevant harmonic concepts used in this thesis, are introduced below.

2.1.1 Fourier Series

Fourier [24] postulated that any continuous function repetitive in an interval *T* can be represented by the summation of a DC component, a sinusoidal component and a series of higher-order sinusoidal components at frequencies that are integer multiples of the fundamental frequency [2, 24]. An illustration of fundamental and harmonic components are shown in Figure 2.1 below.

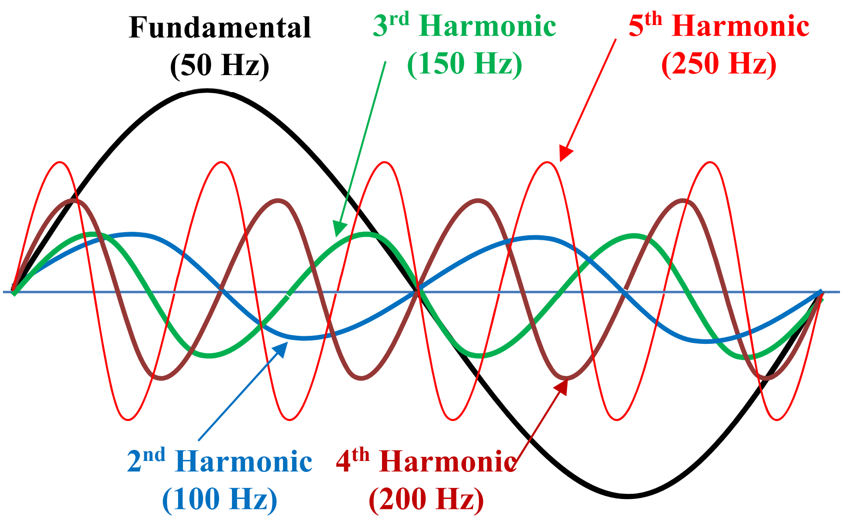


Figure 2.1 – A Sinusoidal waveform with fundamental frequency 50 Hz and its harmonics 2nd (100 Hz), 3rd (150 Hz), 4th (200 Hz) and 5th (250 Hz)

The individual harmonic signals can be characterised in either time or the frequency domain. Description in the frequency domain, which provides information of amplitude (rms values) and phase angle at each harmonic order, is more commonly used [1, 2]. Subsequently, any non-sinusoidal periodic function *u(t)* can be represented as an infinite series of sine and cosine functions and coefficients as shown below:

$$u(t) = A_0 + \sum_{h=1}^{\infty}[A_h cos(h\omega_0 t) + B_h sin(h\omega_0 t)] = A_0 + \sum_{h=1}^{\infty} C_h cos(h\omega_0 t + \varphi_h) \qquad (2.1)$$

where

u(t): a periodic function of frequency f_0, angular frequency $\omega_0 = 2\pi f_0$, and period $T = 1/f_0 = 2\pi/\omega_0$.

h: harmonic order represented as integers 1, 2, 3, etc.

A_0, A_h, B_h: are the peak magnitude of DC and complex (real and imaginary) sinusoidal components at harmonic h

$C_1 Cos(\omega_0 t + \varphi_1)$ represents the fundamental component.

$C_h Cos(h\omega_0 t + \varphi_h)$ represents the h^{th} harmonic component with peak amplitude C_h, frequency $h\omega_0$ and phase φ_t relative to the fundamental.

Fundamental frequency f_0, is either nominally 50 Hz or 60 Hz, therefore harmonic frequencies hf_0 appear as multiples of 50 Hz or 60 Hz. A fundamental of 50 Hz will be assumed for the remainder of this thesis (as that is what is applied in Australia).

The Fourier series coefficients C_1, C_2,..., C_h and their relative phases φ_1, φ_2, … φ_t constitutes the spectrum of the non-sinusoidal waveforms as shown below:

$$A_0 = \frac{1}{T}\int_0^T u(t)dt = \frac{1}{2\pi}\int_0^{2\pi} u(t)dx,\ where\ x = \ \omega_0 t \tag{2.2}$$

$$A_h = \frac{2}{T}\int_0^T u(t)\cos(h\omega_0 t)dt = \frac{1}{\pi}\int_0^{2\pi} u(t)\cos(hx)dx \tag{2.3}$$

$$B_h = \frac{2}{T}\int_0^T u(t)\sin(h\omega_0 t)dt = \frac{1}{\pi}\int_0^{2\pi} u(t)\sin(hx)dx \tag{2.4}$$

$$C_h = \sqrt{A_h^2 + B_h^2} \tag{2.5}$$

$$\varphi_h = tan^{-1}\left(\frac{A_h}{B_h}\right) \tag{2.6}$$

2.1.2 Harmonic Indices

Total Harmonic Distortion (THD) is the most commonly used measure to quantify levels of distortion. Voltage THD is defined as the root mean square (rms) of the harmonics expressed as a percentage of the fundamental component as per (2.7).

$$THD_U = \frac{\sqrt{\sum_{h=2}^{N} U_h^2}}{U_1} \tag{2.7}$$

where

U_h: rms voltage at harmonic order *h*.

N: maximum harmonic order to be considered, can be up to 100.

U_1: fundamental line to neutral rms voltage.

Similarly, Current THD could also be expressed as:

$$THD_I = \frac{\sqrt{\sum_{h=2}^{N} I_h^2}}{I_1} \tag{2.8}$$

However, under light load conditions, i.e. when the fundamental current is low, the THD_I value for input current can appear to be very high and cause false alarms. Under such scenarios, current distortion should be expressed as Total Demand Distortion (TDD) instead, which is also referenced in the harmonic standard IEEE-519 [15], as described below:

$$TDD = \frac{\sqrt{\sum_{h=2}^{N} I_h^2}}{I_R} \tag{2.9}$$

where

I_h: single frequency rms current at harmonic order h.

I_R: fundamental rms rated current.

2.2 Effects of Harmonics

The main effects of voltage and current harmonics on power systems, extracted from [1, 2, 12, 23, 25], are summarised below:

- A reduction in the efficiency of the generation, transmission and utilisation of electric energy. This may be through increased losses (heating) of generator/motor/transformer windings, lines or at customer equipment level, e.g. negative torques in induction motors;

- Premature aging of the insulation of electrical plant and components leading to a shortened lifespan of equipment such as capacitors (e.g. breakdown of dielectric materials), reactors, transformers and motors, and general overheating of equipment, including phase and neutral conductors;

- Malfunctioning of system or plant components, measurement instruments, control and protection systems and mal-operation of protection causing tripping of circuit breakers;

- Lower system power factor and damage to power factor correction equipment;

- Transformers, magnetisation non-linearity – Inrush current harmonics and DC magnetisation, and increase circulating currents and earth-fault currents;

- Adverse effects on static (power electronic) converters' components, control systems of converters (e.g. phase lock loop), characteristics of converters and electromagnetic compatibility issues;

- Contributes to composite resonances that lead to system instability.

The combination of high penetration of large power electronic converters connected to the transmission system and increased power electronics-based consumer loads in the distribution network can severely affect the power system [1]. Constant power loads such as variable speed drive motors, early generation of roof top solar inverters (e.g. pre-2015), and switch-mode power supplies present a small signal impedance or resistance to the system that is negative, such that any rise in voltage causes current to fall [1, 4, 6]. This reduces the energy absorption capability of the power system. It can be expected that the continuous addition of such loads to the power system will eventually lead to system instability [1, 23].

2.3 Harmonic Resonance

The effects of harmonic currents and voltages on the network are significant and may become more profound under series and parallel resonance conditions. In particular, harmonic currents that are coupled with parallel resonance condition in the network can cause excessive harmonic voltages.

Parallel resonances can occur in a variety of ways, the simplest scenario being a shunt capacitor connected to the same bus as the harmonic source [1]. A parallel resonance then may occur between the system impedance and the capacitor. Under the assumption that the system impedance is entirely inductive, the parallel resonance frequency can be determined from [1]:

$$f_p = f\sqrt{\left(\frac{S_S}{S_C}\right)} \tag{2.10}$$

where

f: fundamental frequency (Hz),

f_p: parallel resonant frequency (Hz),

S_S: short circuit rating (VA),

S_C: capacitor rating (VAr)

In practice, the system impedance is not purely inductive; hence, the application of equation (2.10) needs to be adjusted accordingly. A common approach used to determine parallel resonance condition in the network is harmonic frequency scan analysis that will be discussed in the next section. Alternatively, resonance conditions can also be detected based on measurements of harmonic currents and voltages in the network. Generally, if the harmonic current flowing into the power system from a bus is small, while the harmonic voltage is high, parallel resonance within the power system is indicated. The most common and onerous harmonic issue in transmission system is the magnification of low-order harmonics due to resonances [2].

When AC and DC systems are interconnected by a static power electronic converter, the system impedances interact via the converter characteristics to create entirely different resonant frequencies [1]. The term "composite resonance" has been proposed in [26] to describe this type of resonance which occurs as a result of interaction between the AC and DC sides of the static converters [27]. A composite resonance can be excited by a small distortion source in the system, or by an imbalance in the converter components or its control systems [27]. The resulting amplification of the small source by the resonant characteristics of the system can compromise the normal operation of the converter and could lead to system instability. Detailed modelling of static controllers' interactions that can lead to system instability can be found in [1, 26, 27].

Managing harmonic resonances in the transmission network is the sole responsibility of network operators. However, there is still a lack of effective methodologies and recommended practices to better manage harmonics in modern power systems, especially in those with high penetration levels of static converters.

2.4 Major Transmission System Equipment and Harmonic Sources

The review in this section covers major equipment and harmonic sources that are significant to transmission systems and used in the case studies of this research project. This includes synchronous generators, transformers and reactors, loads, power electronic conditioning and conversion equipment.

2.4.1 Synchronous Generators

In most cases, synchronous machines do not generate harmonics but help to absorb harmonics from the network. However, they can become a harmonic current source under two conditions: The frequency conversion effect, and non-linear characteristic effect due to magnetic saturation [23]. The frequency conversion effect occurs when a synchronous generator is connected to an unbalanced system, whereby the generator can experience a negative sequence current in the rotor and induced a third harmonic current on the stator. If a magnetic circuit of the stator becomes saturated, it becomes an additional source of harmonics.

2.4.2 Transformers and Reactors

Transformers and reactors are generally considered linear devices. Under the no-load condition, the primary of a transformer is practically balanced. However, when a transformer is subjected to high voltage condition it can run into saturation [23]. The symmetrical magnetising current associated with a single transformer core saturation contains odd harmonics. Under unbalanced conditions, the transformer excitation current can contain both odd and even harmonic components. The asymmetry condition can be caused by any load connected to the secondary side of the transformer. Similarly, the magnetising impedance of saturated transformers and shunt reactors have non-linear characteristics. Saturated magnetic cores may generate harmonic currents during steady-state as well as transient and over-voltages following a major switching operation, with a critical case being the energisation of the transformer itself [1]. In the past, transformers were evaluated for iron core losses, mainly under sinusoidal excitation. These transformers may operate in environments that now have very high background harmonics [28].

2.4.3 Power Electronic Based Equipment

Power electronic-based equipment has penetrated modern power systems extensively in recent years due to their affordable cost and flexible application. Generally, power electronic circuits include converters, rectifiers and inverters. Typical examples of power electronic-based harmonic sources in transmission systems include Static VAr Compensators (SVCs), STATCOMs, HVDC converters, active harmonic filters, and inverters for wind, solar and battery storage plants. Their harmonic emissions and profiles heavily depend on the topology of power electronic switches and associated control systems [5]. There are many variations of power electronic converter topologies and associated control system schemes, each having its harmonic profiles. Furthermore, network interactions contribute significantly to the variations of harmonic emissions of their emissions. Therefore, additional challenges are anticipated for harmonic management in modern power systems that have a large installed population of power electronic equipment.

2.4.3.1 Static VAr Compensator

SVCs provide superior voltage response to power system needs. SVCs are a major source of harmonics due to distortion from its Thyristor Control Reactor (TCR). Currents through the reactors can be controlled swiftly by varying the thyristor firing angles α within the range of 90° < α < 180° (can also be expressed in term of reactor conduction angles). As the firing angle α is delayed, further from 90° toward 180°, the fundamental frequency component is gradually reduced and harmonic components increase. The magnitude of fundamental component current through the reactor can be expressed as a function of the firing angle [5]:

$$I_f(\alpha) = \frac{V}{\pi X_L}(2\pi - 2\alpha + sin2\alpha) \tag{2.11}$$

where

> V: voltage magnitude of $V_{TCR}(t)$
>
> X_L: reactance of the linear reactor at the fundamental frequency.

The harmonic magnitude of the current $I_{TCR}(t)$ can be calculated as a function of the firing angle α:

$$I_h(\alpha) = \frac{4V}{\pi X_L}\left(\frac{hsin(\alpha)\cos(h\alpha) - cos(\alpha)\sin(h\alpha)}{h(h^2-1)}\right) \tag{2.12}$$

for $h = 2k+1$, with $k = 1,2,3\ldots$

This expression indicates that TCR generates the 3rd, 5th, 7th, 9th, … etc. harmonics (i.e. odd harmonics). The harmonic profile of the SVC is consistent as it only depends on the firing angle α. In some cases, the SVC control system is implemented with single-phase control to balance negative phase sequence voltages at the connection point. When the SVC is in single-phase control mode, triplen harmonics will no longer be trapped in the transformer delta. Therefore, triplen harmonics, especially significant third harmonic, will be present at the connection point in single-phase operating mode [5]. An illustration of SVC TCR harmonic currents is shown in Figure 2.2 below.

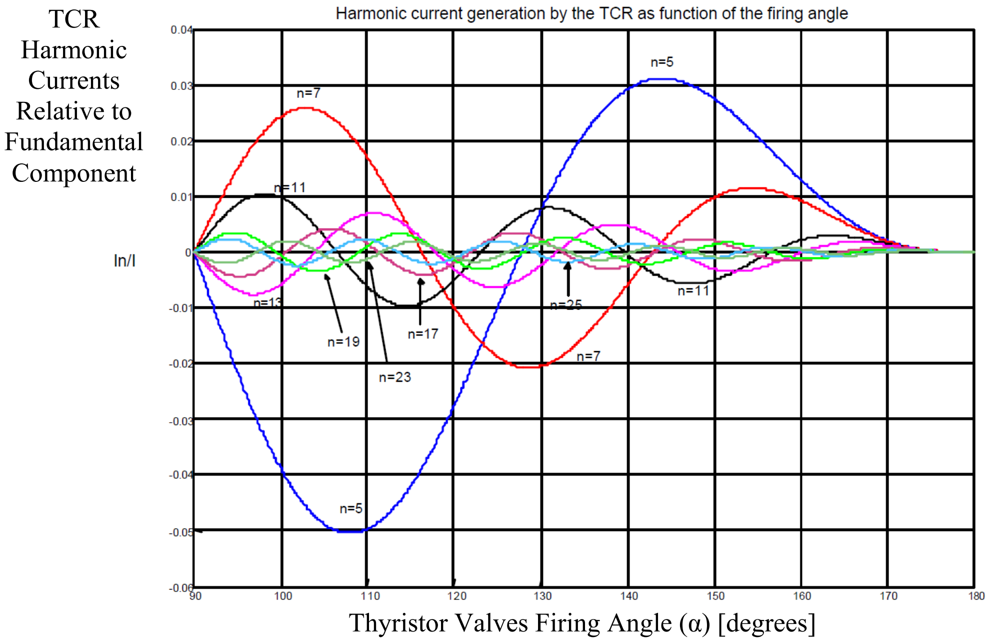
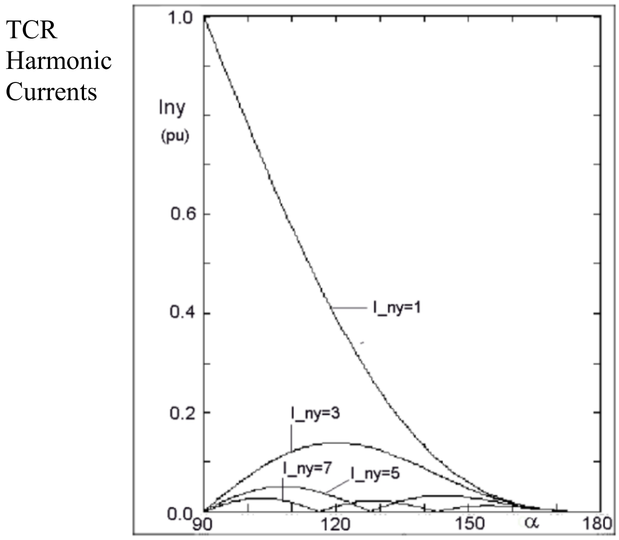


Figure 2.2 – Illustration of SVC TCR Harmonic Currents

In modelling, SVCs can be considered as a network element due to their coupling transformer, reactors, capacitors and capacitor banks. Its harmonic impedance model is often represented with a power transformer, capacitor banks (including series inrush reactors) of Thyristor Switch Capacitor (TSC), harmonic filters and Thyristor Controlled Reactor (TCR) [5, 23]. SVC harmonic characteristics are heavily dependent on the operating points of the SVC to meet the reactive power demands of the networks. The SVC reactive currents are regulated by the control system acting on the thyristor valves firing angle α. The typical harmonic current profile of an SVC is illustrated in Figure 2.3 below.



(a)
Thyristor Valves Firing Angle (α) [Degree]

n	k	$\alpha_{n,max}$	$I_{n,max} / I$
3	1	$2\pi/3$	0.1378
5	2	$3\pi/5$	0.0505
7	3	$4\pi/7$	0.0259
9	4	$5\pi/9$	0.0157
11	5	$6\pi/11$	0.0105
13	6	$7\pi/13$	0.0075
15	7	$8\pi/15$	0.0057
17	8	$9\pi/17$	0.0044
19	9	$10\pi/19$	0.0035
21	10	$11\pi/21$	0.0029
23	11	$12\pi/23$	0.0024
25	12	$13\pi/25$	0.0020

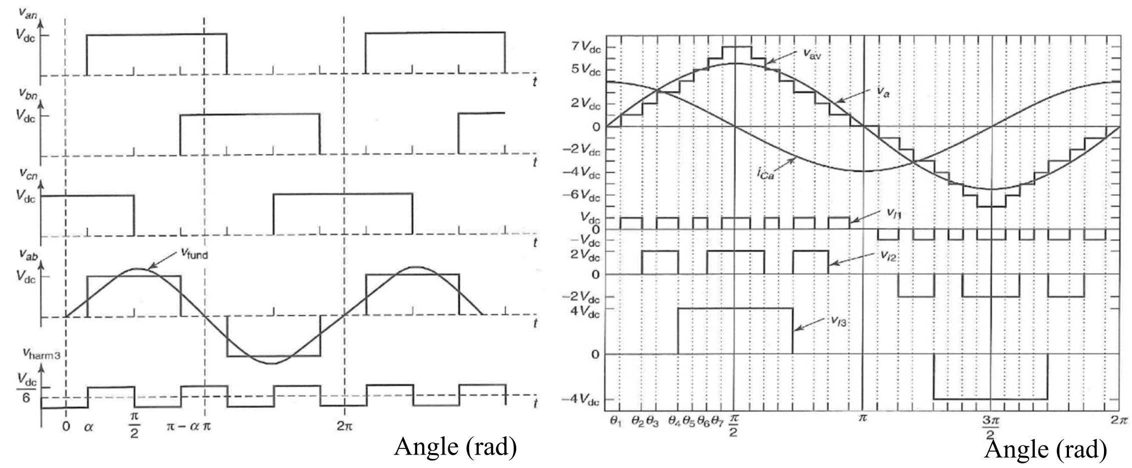
(b)
Maximum amplitude of the TCR characteristic harmonic generation

Figure 2.3 – Illustration of SVC TCR harmonic characteristics and profiles [5].

2.4.3.2 Static Compensator

The Static Compensator (STATCOM) is a custom power device comprising of a voltage source inverter, a DC capacitor and a coupling transformer. Similar to the SVC, STATCOM is a shunt compensation system that provides voltage support at the connection point. However, the design and operation of a STATCOM are very different to that of an SVC [5]. STATCOM inverters use Gate-Turn-Off (GTO) thyristor, Insulated Gate Bipolar Transistor (IGBT) or Integrated Gate Commutated Thyristor (IGCT) switches. For Pulse-Width Modulation (PWM) type of control techniques, the harmonic spectrum generated by the STATCOM is shifted towards higher frequencies, which may lead to resonance problems if one of the many alternate resonant points of the transmission system impedance becomes excited [23]. At harmonic frequency, the STATCOM is presented as a harmonic voltage source, but this will include no explicit representation of the DC capacitor. To model the harmonic profile of a STATCOM accurately, parameters of DC capacitor, charging and discharging sequences of the control systems must also be included in the harmonic models. The combination of different topologies and various control schemes for STATCOMS results in differences in harmonic profiles.

The STATCOM capacitor size has a strong influence on the cross-couplings between phases and between harmonics [23]. Therefore, harmonic voltage responses can be quite different at different operating points. It is practically impossible for the utility to accurately model all different STATCOM voltage sources at harmonic frequencies due to intellectual property boundary. The harmonic profile of a STATCOM is usually provided by the manufacturer in the form of a power system software model. It is not always possible for the utility to validate these models with the real operational network. Typical voltages of STATCOMs are illustrated in Figure 2.4 below



(a) 6-Pulse 180 Degree Conduction Sequence (b) 15 Levels Converter Voltage

Figure 2.4 – Illustration of two types of STATCOM Voltages (6 Pulse and 15 level converters) [5]

2.4.3.3 Large Scale Renewable Generation Inverters

A few decades ago, harmonics in transmission were relatively low due to the network absorption capability provided by synchronous rotating generators and to a lesser degree of attenuation from connected loads. It has been forecasted that by 2030 many power systems would reach penetration levels of up to 30% of harmonics producing renewable generation [28]. This will be coupled with a reduction of harmonic absorption capability due to the retirement of synchronous generators. It has also been estimated that over the next decade harmonic producing loads will account for more than 60% of the total loads in the power system [28]. The Australian and international power system landscapes have already changed and will continue to move rapidly towards more renewable energy sources and power-electronic loads. The continuing trend of higher penetration of both converter-based generation sources and power electronic equipment is inevitable.

Inverter based renewable generation sources such as solar, wind and battery storage, are major sources of harmonics in modern power systems. It is not practical to examine harmonic levels and profiles produced from all types of inverter topologies and control schemes because they vary significantly. Details of technologies used in renewable generation sources and associated harmonics are extensively covered in [4-7, 29]. During the development of mitigating measures for inverter harmonic emissions, the following challenges have been encountered [30]:

(i) Lack of power system frequency-dependent impedance information;

(ii) Inadequate information on solar inverter harmonic characteristics, including harmonic current profiles and Norton equivalent impedance; and

(iii) Inadequate solar farm harmonic assessment metering and methodology.

Topologies of grid-connected converters for solar, wind and battery plant are similar to PWM converters of a basic STATCOM – Advanced STATCOMs often include multi-level converter structures. Sample harmonic profiles of solar and wind plants are illustrated in Figure 2.5 – 2.7 below [30, 31]. These figures show different harmonic profiles between solar and wind inverters due to their topology and associated control systems. Therefore, their requirements for harmonic allocation can be different. It is noted that the characteristic harmonics of 5th, 7th, 11th and 13th are generally present, along with lower levels at other harmonics, for both odd and even orders.

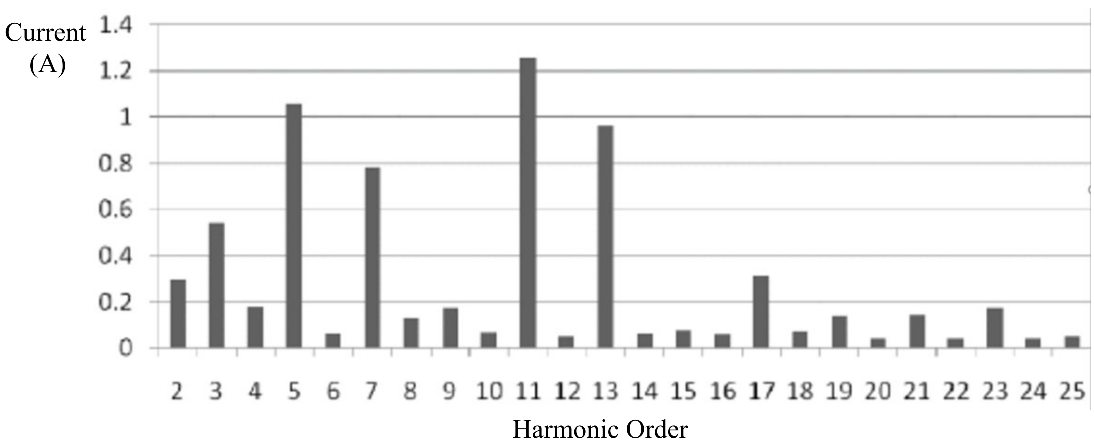


Figure 2.5 – A Sample Harmonic Profile of a 20MW Solar Farm [31]

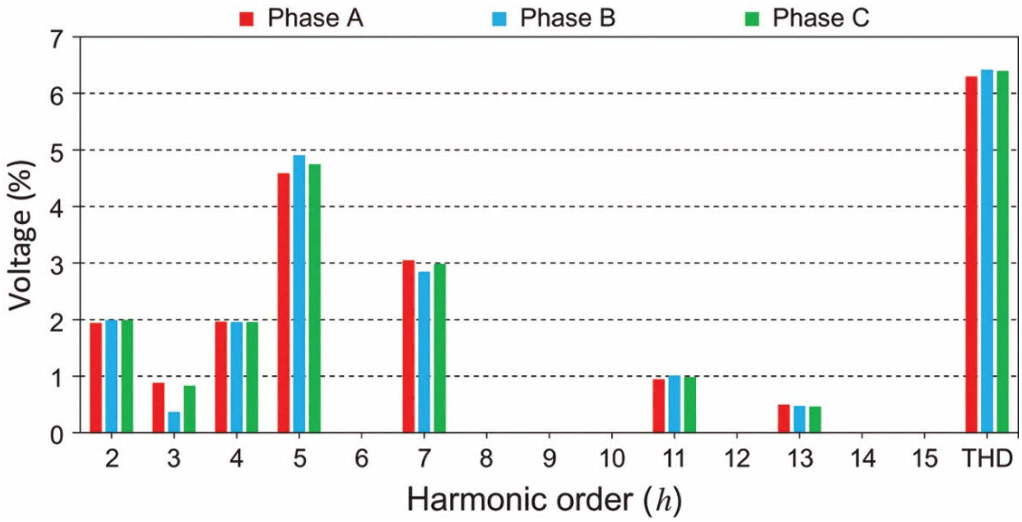


Figure 2.6 – A Sample Harmonic Profile of a Wind Farm [31]

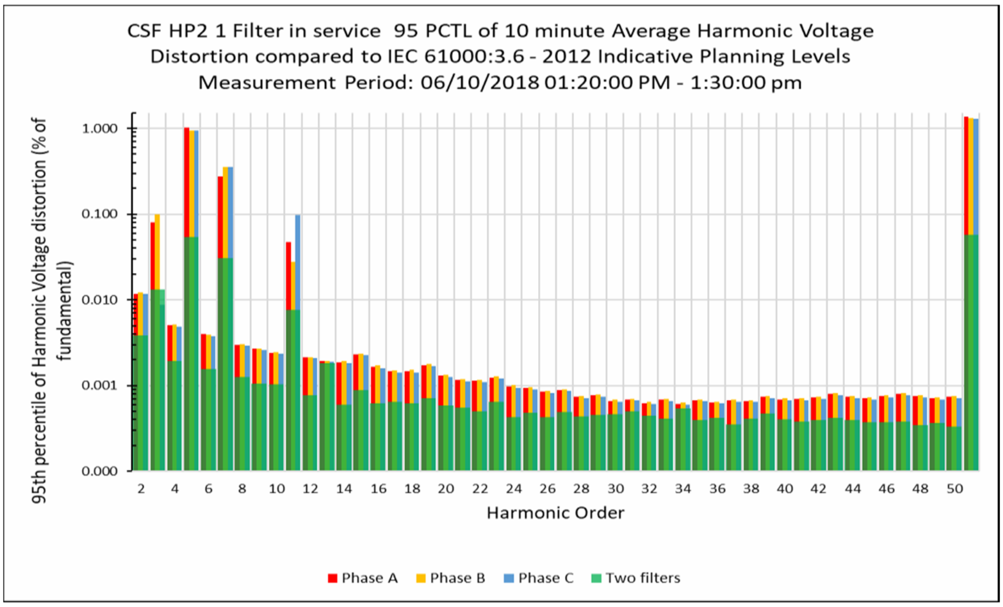


Figure 2.7 – Harmonic Profile of another Solar Farm with and without C type Harmonic Filters [30]

2.5 Harmonic Models, Admittance, Impedances and Computations

Harmonic modelling is one of the most important tasks in harmonic management. Harmonic studies depend on detailed harmonic models of network elements, plant and network connectivity. Various models for harmonic studies may be found in [1, 5-7, 22, 23]. It appears that only the modelling methods recommended in [22] were based on practical experiments and measurements, while others appear to be based on software simulation and pure mathematical models.

Depending on the purpose of harmonic studies, single-phase or three-phase models may be required. For example, the three-phase nature of power systems always results in some load or transmission line asymmetry, as well as circuit coupling [1]. Under such scenarios, if the detailed analysis requires a three-phase system model, elements for the admittance matrix are themselves 3 x 3 matrices consisting of self and transfer admittances between phases. This thesis focuses on harmonic allocation to major loads in balanced transmission systems. Therefore, the system harmonic model can be represented by a single-phase equivalent model and harmonic voltages calculated by direct solution of the linear equation [1]. The steady-state analysis of linear circuits operating under sinusoidal and non-sinusoidal conditions may be carried out using phasor analysis [23]. Generally, a linear circuit operating under non-sinusoidal conditions is well represented by the following linear system of equations:

$$\begin{bmatrix} I_h^1 \\ I_h^2 \\ \vdots \\ I_h^j \\ \vdots \\ I_h^N \end{bmatrix} = \begin{bmatrix} Y_h^{1,1} & Y_h^{1,2} & \dots & Y_h^{1,j} & \dots & Y_h^{1,N} \\ Y_h^{2,1} & Y_h^{2,2} & \dots & Y_h^{2,j} & \dots & Y_h^{2,N} \\ \vdots & \vdots & \ddots & \vdots & \ddots & \vdots \\ Y_h^{j,1} & Y_h^{j,2} & \dots & Y_h^{j,j} & \dots & Y_h^{j,N} \\ \vdots & \vdots & \ddots & \vdots & \ddots & \vdots \\ Y_h^{N,1} & Y_h^{N,2} & \dots & Y_h^{N,j} & \dots & Y_h^{N,N} \end{bmatrix} \cdot \begin{bmatrix} V_h^1 \\ V_h^2 \\ \vdots \\ V_h^j \\ \vdots \\ V_h^N \end{bmatrix} \tag{2.13}$$

Alternatively, in the compact form: $[\mathbf{I}_h] = [\mathbf{Y}_h]. [\mathbf{V}_h]$ (2.14)

where

I_h^j : phasor current at frequency h injected at node j, i.e. $I_h^j = |I_h|\angle\phi_h$.

$Y_h^{i,j}$: equivalent admittance (or mutual admittance) at frequency h between nodes *i* and *j*.

$Y_h^{j,j}$: self-admittance of bus *j* at frequency *h*.

V_h^j: phasor voltage at frequency *h* at node *j*.

N: number of nodes of the electric network.

$[\mathbf{Y_h}]$: nodal Admittance Matrix of the network at frequency *h*.

The linear equation (2.14) is solved at each frequency *h* and the final result is obtained by superposition. The inverse of matrix $[\mathbf{Y_h}]$ gives the impedance matrix $[\mathbf{Z_h}]$, where the impedance $Z_h^{j,j}$, an entry of matrix $[\mathbf{Z_h}]$, is known as the driving point impedance of node *j* at different harmonic frequencies.

In practice, equation (2.13) needs to be applied in conjunction with the IEC summation law in [10]. While equation (2.13) is generally applied to time-invariant cases, the IEC summation law approach requires parameters to be represented statistically, i.e. as 95th or 99th percentiles of time-varying rms values (the phase information of V, I and network impedances is ignored), before being combined. Both direct application of equation (2.13) and the IEC summation law approach is utilised in this thesis (for comparative purposes).

Detailed harmonic models of transmission lines, transformers, generators, shunt series elements, series elements and distribution loads, which are covered extensively in [1, 22, 23], are required to build up the network admittance matrix $[\mathbf{Y_h}]$. Harmonic models used in this research project are based on the CIGRE/CIRED joint working group CC02 document [22].

Most power system non-linearity manifest themselves as harmonic current sources [1]. However, harmonic voltage sources are utilised to represent the background distortion that already exists in the network before the installation of the new harmonic source.

Frequency scan analysis is used to derive the frequency response of a network looking from a specified bus. For example, at each frequency h, one per unit of harmonic current (harmonic current source) is injected to the specified bus, the corresponding harmonic voltage response can be calculated from equation (2.13). Alternatively, one per unit of harmonic voltage can be used to calculate the effects of background harmonic voltages present at a specified point in the network. Equation (2.13) can also be used to derive the harmonic voltage transfer to the rest of the network.

Calculation of harmonic currents, voltage and harmonic power flow often requires computer-aided software to process a large number of network admittance/impedance matrices over a wide range of frequencies. The codes can be developed in many software platforms, e.g. Matlab, Mathcad or FORTRAN, etc., and implemented through the following stages [1]:

- Computation of the admittance matrices of individual components at specified harmonic frequencies;
- Formation of the system admittance matrices at individual frequencies according to the network topology;
- Calculation of the system harmonic voltages at all system nodes given the harmonic current injections at the nodes containing non-linear plant components.

Practical application of harmonic models and computation of harmonic currents, voltages and power flow will be examined in detail in Chapter 3. Detailed modelling of network elements based on CIGRE guideline [23] is included in Appendix B, C, and D.

2.5.1 Characteristics of Network Elements in Transmission Systems

A typical transmission network is made up of major network elements such as long transmission lines, large power transformers, shunt capacitor banks, reactors and large static (power electronic) converters. Network participants connecting to the transmission network consist of generators, which include synchronous rotating machines (e.g. hydro and thermal) and asynchronous or inverter-based renewable generation systems (e.g. wind and solar farms), distribution loads at bulk supply points, large mining and industrial loads, and interstate interconnectors. This section specifically focuses on the review of harmonic characteristics of transmission network elements only and excludes network participants.

The combination of transmission lines, high voltage capacitor banks (including series inrush reactors) and other network elements such as transformers, motors and generators can result in unpredictable and very complex transmission network impedance characteristics. There remains a lack of measurements to verify the models such that the true values are never fully known. In addition, as more renewable generation sources that have large variations in topologies and harmonic characteristics are connected to the transmission systems, characteristics of network harmonics and impedances can change rapidly with time and frequencies and much more complex to measure, model and manage.

2.5.2 Long Transmission Line Characteristics

Characteristics of long transmission lines are well researched [1-2, 17, 18] and typically have harmonic impedances appearing as both parallel and series resonances at periodic frequencies. According to models in [1, 22], at series resonance frequencies, the transmission line impedance transitions from being capacitive to inductive and the impedance angle changes from -90° to +90°. Conversely, at parallel resonance frequencies the line impedance changes from being inductive to capacitive, the impedance angle changes from +90° to -90°. The rate of change of the angle characteristics depends on the resistive component associated with the transmission line at harmonic frequencies. These characteristics have major effects on the transmission network harmonic impedances.

Long transmission lines are often represented by the equivalent PI model as shown in Figure 2.8 below. The PI model may use lumped or corrected values for Z and Y. Corrected components (hyperbolic corrections as given by equations (2.15) and (2.16)) have been used throughout this thesis to accurately represent a line.

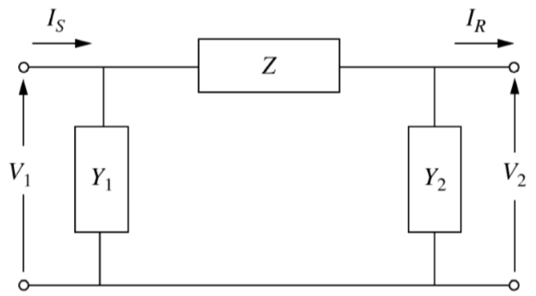


Figure 2.8 – The equivalent PI model of a long transmission line

$$Z = Z_0 sinh(\gamma.l) \tag{2.15}$$

$$Y_1 = Y_2 = \frac{1}{Z_0}\frac{cosh(\gamma.l)-1}{sinh(\gamma.l)} = \frac{1}{Z_0} tanh\left[\frac{(\gamma.l)}{2}\right] \tag{2.16}$$

where:

$\gamma = \sqrt{Z'.Y'} = \alpha + j\beta$: propagation constant. (2.17)

$Z_0 = \sqrt{\frac{Z'}{Y'}}$: characteristic Impedance of the line. (2.18)

V_1 and V_2 : forward and reverse travelling voltages respectively.

$Z' = r + j2.\pi.f.L$: series impedance per unit length. (2.19)

L : line series inductance per unit length.

$Y' = g + j2.\pi.f.C$: line shunt admittance per unit length. (2.20)

C : line shunt capacitance per unit length.

l : line length.

To illustrate the characteristics of the impedance in Figure 2.8, these are plotted against frequency in Figure 2.9 for a 220 kV 230 km line.

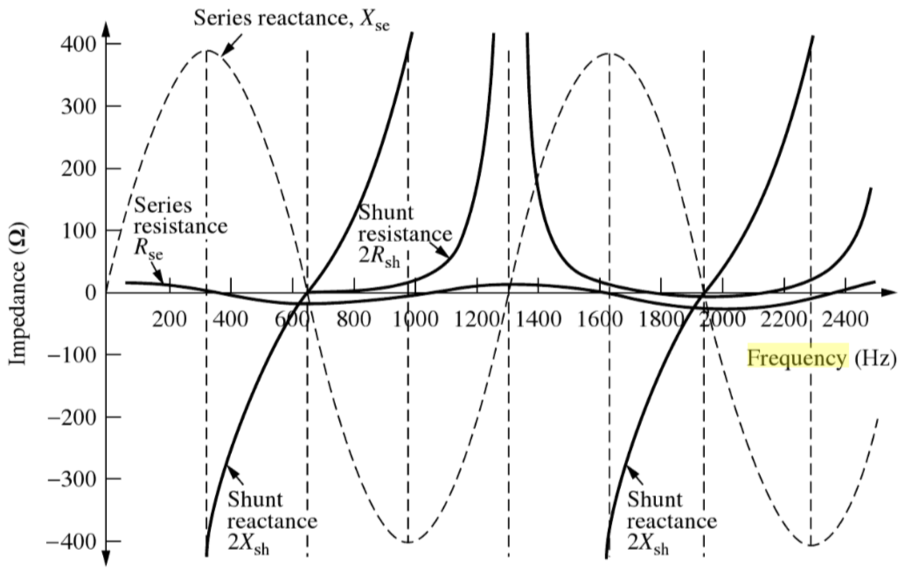


Figure 2.9 – Impedance versus frequency for the equivalent PI model (skin effect included) [1]

The skin effect of the transmission line accounts for the internal impedance of the conductors [1, 32]. Both resistance and reactance vary with frequency in a non-linear manner and need to be computed at each frequency of interest. The non-linear variation of these parameters with frequency was also recognized in [32]. CIGRE model [22] suggested that to take into account the skin effect, the value of the resistance R_h at any harmonic number h is reduced from its 50 Hz value R_1 as follows:

$$R_{dc} = \frac{R_1 - 0.004398.l}{0.938} \quad (2.21)$$

$$x = 0.3545.\sqrt{\frac{h}{R_{dc}/l}} \quad (2.22)$$

For x $\leq$ 2.4:

$$R_h = R_{dc}(0.035.x^2 + 0.938) \quad (2.23)$$

For x > 2.4:

$$R_h = R_{dc}(0.35.x + 0.3) \quad (2.24)$$

According to [17], there is no significant impact of the modelling of the skin effect on the complex self-impedance for harmonics lower than the 8th harmonic. The same study also suggested that at resonant frequencies, the amplitude of the self-impedance could be reduced up to 50% if the skin effect of the transmission lines has been modelled. Modelling of the skin effect of transmission lines does not influence the resonant frequencies of the self-impedance but does influence network impedance angles [17]. However, there is still a lack of information on the importance of network impedance angles that can directly affect the harmonic allocation and filter design [28].

2.5.3 Large Capacitor Bank Characteristics (Harmonic Filters, Detuned and Non-Detuned Capacitor Banks)

Characteristics of large HV capacitor banks and associated inrush (current limiting) reactors have been well documented [25, 28, 33]. There are various types of capacitor banks, the most common types connected to the transmission systems being for voltage support and/or power factor correction and, to a lesser extent, harmonic filters. The former appears both as detuned and non-detuned capacitor banks.

Individual capacitors and reactors have linear frequency dependence, i.e. $X_L = j\omega_0 L$ and $X_C = 1 / (j\omega_0 C)$. However, when they are connected in series or parallel, the overall frequency response is no longer linear. In particular, the impedance of voltage support (detuned or non-detuned) capacitor banks with series current limiting/inrush reactors and harmonic filters become inductive at frequencies above the series resonance frequencies. These capacitor banks often have different series resonance frequencies depending on the combination of their inductive and capacitive components (L and C) [23]. As a result, the network harmonic impedances and their resonant frequencies can vary significantly due to different mix of capacitor banks, reactors and transformers (inductive impedance) under different network scenarios.

2.5.4 Aggregated Load Models

Consumer loads play a very crucial role in the harmonic network characteristic. They constitute not only the main element of the damping component (e.g. absorbing harmonic power at low frequencies) but may also affect the resonance conditions, particularly at high frequencies [1]. Historical measurements have shown that maximum load conditions result in a lowering of the impedance at lower frequencies, but cause an increase at higher frequencies [22]. Computer simulations have indicated that depending on the range of harmonic frequencies, the addition of load can result in either an increase (at high frequencies) or a decrease (at low frequencies) in harmonic currents flowing in the network [23].

The impact of load modelling on the resulting harmonic currents and voltages is particularly relevant at the parallel resonance frequencies. Differences in the calculated impedance at the resonance frequency can vary significantly depending on the load model. Practical application of three load models recommended in CIGRE guideline [22] is discussed in Chapter 3 and details documented in Appendix B, Section B.4.

2.6 Existing Harmonic Management and its Deficiencies

Harmonic standards may be system standards, connection standards, or a combination of both. The emphasis of a system standard is on the level of harmonics that can be tolerated in the system [1]. Harmonic allocation to loads can be expressed as a level of current or voltage, which may not be exceeded, or as incremental limits allowing small changes to the harmonic source with limited consideration of system effects. With distorting loads of higher rating, existing harmonic content needs to be taken into account to determine if limits are likely to be exceeded. A common approach adopted by transmission utilities is to allocate in terms of harmonic voltage levels at the Point of Common Coupling (PCC). This means that harmonic sources connected to a strong (high short circuit power) PCC may benefit more than those connected to a weak (low short circuit power) PCC. In addition, if the existing harmonic levels are high at a PCC, the new harmonic source may receive very small allocations.

2.6.1 Harmonic Management and Planning in Transmission Systems

Recommendations for harmonic management and planning is broadly covered in [1-2, 23, 34-36] and IEC standards. Generally, the process includes:

- Harmonic planning;
- Harmonic allocations;
- Harmonic measurement systems and reports;
- Harmonic frequency scans;
- Harmonic monitoring measurement and compliance assessment;
- Harmonic elimination/mitigation options.

In the past, Australian utilities had the freedom to choose what standards to adopt and how to implement the processes above. This led to inconsistent practices and implementation across the different networks within the National Electricity Market (NEM). Subsequently, misinterpretation of the NER rules often occurred due to a lack of clarity for detailed implementation of the rules. So far, these have not yet become a major issue mainly due to the inherently large margin between network absorption capability and harmonic emissions. As a result, most utilities still manage harmonics in their network in a reactive manner; some do not have adequate skills and resources to actively monitor and manage harmonic compliance in their networks. However, more recently the trend in Australia is of harmonics increasing both from large converter sources directly connected to the transmission system, and from distribution harmonic sources appearing via bulk supply points. There is also a lack of foreseeable investment in the network absorption capability. Therefore, it is anticipated that the remaining margins of the network absorption capability will quickly be utilised, or removed as a result of the early retirement of synchronous generators, and that will eventually lead to harmonic compliance issues. Despite existing harmonic guidelines and recommendations, there is still no consistent and practical harmonic framework to help improve the understanding and management of harmonics proactively.

2.6.2 IEC 61000 Series of Standards

The International Electro-Technical Commission (IEC) is widely known for its roles in setting power quality standards. The IEC has defined a series of Electromagnetic Compatibility (EMC) standards to deal with power quality issues in power systems. The IEC 61000 series [37] includes harmonics and inter-harmonics as one of the conducted low-frequency electromagnetic phenomena [1] and provides a basis for global harmonic coordination. Individual countries make their adjustments to suit relevant characteristics of their power systems [1]. For example, power systems in Australia and New Zealand often include remote generation sources providing an electricity supply to a few regions or load centres. This results in long transmission lines and low fault levels in parts of the network that increases the vulnerability of the system to harmonic propagation and penetration [1]. These factors present unique issues compared to those experienced in other countries, e.g. the UK and Europe.

An important point highlighted in [1] is that no standard relating to system harmonic content can be regarded as permanent, but rather as the current interpretation of the system requirements, taking into account the state of monitoring and modelling techniques. The standards need to be regularly reviewed and improved as better measurements and analytical techniques are developed.

To date, there is still no clear requirements on how pre-connection and post-connection compliance should be handled. In practice, they are often handled differently by various practitioners. The first is based on a design model of the plant and allows a decision to be made for Stage 2 compliance. If the installation fails, the same models, plus models for appropriate transmission line scenarios, can be used for filter design. Post-connection compliance is a test to show the accuracy of the plant model and filter design method were satisfactory, although it is somewhat complicated by the need to have the transmission authority specify appropriate scenarios. Post-connection compliance is outside the scope of this thesis.

As a signatory nation to the General Agreement on Tariffs and Trade (GATT), Australia is obliged to adopt technical standards approved by the International Electrical Commission [38]. As a result, Australia adopted the IEC technical report IEC/TR 61000-3-6:1996 [39], with minor modifications, as the Australian standard AS/NZS 61000-3-6 [9]. This standard superseded the previous Australian Standard AS 2279.2 – 1991 [20]. Standards Australia also released the Handbook HB-264 [34] with recommendation for the application of AS/NZS 61000-3-6 [9], focusing on distribution systems. The latest version of the IEC technical report IEC /TR 61000-3-6, Ed. 2:2008 [10] includes many updates and amendments and supersedes the previous version [39].

Similarly, the Australian National Electricity (NER) Rules [19], in which various parts are regularly updated, superseded the draft version of the Queensland Grid Code [35] that was developed by the Queensland state regulator before the establishment of the Australian Energy Market and the National Electricity Rules (NER) [19]. The current NER at the time of writing this thesis is version 156 and was published by AEMC on the 17th December 2020 [19]. It is important to note that the NER [19] still refers to the old Australian Standard AS/NZS 61000-3-6 [9], instead of the latest IEC version.

The main IEC standards dealing with harmonics and inter-harmonics are presented in Table 2.1. Key objectives of some relevant parts of the IEC 61000 series are detailed in Table 2.2 below.

Table 2.1 – Main IEC Harmonic Standards

Subject	Standard
General	IEC 61000-1-4
Emission (description)	IEC 61000-2-2, IEC 61000-2-3, IEC 61000-2-4, IEC 61000-2-6, IEC 61000-2-12
Limits	IEC 61000-3-2, IEC 61000-3-4, IEC 61000-3-6, IEC 61000-3-9, IEC 61000-3-10, IEC 61000-3-12
Testing and Measurement Techniques	IEC 61000-4-7, IEC 61000-4-13, IEC 61000-4-30, IEC 61000-4-31

Table 2.2 – IEC 61000 Parts and Key Objectives

IEC 61000 Series	Key Objectives
IEC 61000-1-4	Provides rationale for limiting power frequency conducted harmonic and inter-harmonic current emissions from equipment in the frequency range up to 9 kHz.
IEC 61000-2-1	Outlines the major sources of harmonics in three categories of equipment: power system equipment, industrial loads and residential loads. The increased use of HVDC, FACTS, Power Electronic based Converters, Renewable Energy Sources has become the main harmonic sources of transmission systems. Medium and small static power converters and electric arc furnaces are the main contributors in the industrial categories. Appliances powered by rectifiers with smoothing capacitors (e.g. computers and television), rooftop solar and home battery storage are the main distorting components in the residential category.
IEC 61000-2-2	Contains a section on the compatibility levels of the harmonic and inert-harmonic voltage distortion in public low-voltage power industry systems.
IEC 61000-2-4	Provides harmonic and inter-harmonic compatibility levels for industrial plant.
IEC 61000-2-12	Address compatibility levels for low-frequency disturbances.
IEC 61000-3-2, 3-4	Limits for harmonic current emissions by equipment with input currents <= 16A.
IEC 61000-3-6	Compatibility levels for harmonic voltages in LV and MV networks as well as planning levels for MV, HV and EHV power systems.
IEC 61000-3-12	Limits for harmonic currents produced by equipment connected to LV systems with input current <= 75A per phase and subject to restricted connection.
IEC 61000-4-7	Testing and measurement techniques. It is a general guide on harmonic and inter-harmonic measurement and instrumentation for power systems and equipment connected thereto.
IEC 61000-4-13	Testing and measurement techniques regarding harmonics and inter-harmonics, including the main signalling at AC power ports as well as low-frequency immunity tests.

The most important matter is the compatibility among different equipment, systems and the grid [3]. Equipment connected to the power system must be able to withstand harmonic distortion (disturbances of voltages and currents) in the network. Equipment immunity levels are set and tested according to the relevant design, manufacturing and testing standards while harmonic distortion levels are managed by the local network utilities. Utilities rely on guiding principles of the current standards and guidelines to set the relevant harmonic planning or compatibility limits in their network.

The main aim of the IEC technical report [10] was to achieve equitable sharing of harmonic allocation for all loads. Harmonic emission rights should be allocated proportionally to the maximum "agreed power" (S_i) of the distorting loads. The report sets requirements on planning levels in the network (MV, HV and EHV) and compatibility (LV and MV) levels between equipment immunity and system disturbance levels. In general, it is expected that equipment must be designed and tested to ensure immunity to harmonic distortion at least up to the compatibility level; utilities are required to manage the system disturbance levels at or below the planning levels (MV, HV and EHV) and compatibility level (LV and MV).

The compatibility levels referenced in [10], for LV and MV only, are based on a stochastic approach rather than deterministic methods. It was noted in [40] that compatibility levels in transmission systems should only be used as a coordination tool rather than enforceable limits – there is no compatibility level for HV and EHV in [10]. Instead, at MV, HV and EHV harmonic voltage planning levels are recommended in [10] as internal objectives for coordinating customer emission levels and systems response at individual buses [40]. Practical management of harmonic compatibility between equipment and transmission network relies on sound knowledge in power system harmonics and best engineering practices. The basic concepts of planning and compatibility levels are illustrated in Figure 2.10 below, extracted from [10]. It shows overlapping between the distributions of disturbance levels and immunity levels within an entire power system [10], noting that ideally at any one site within a well-managed network, a gap would separate the two distributions.

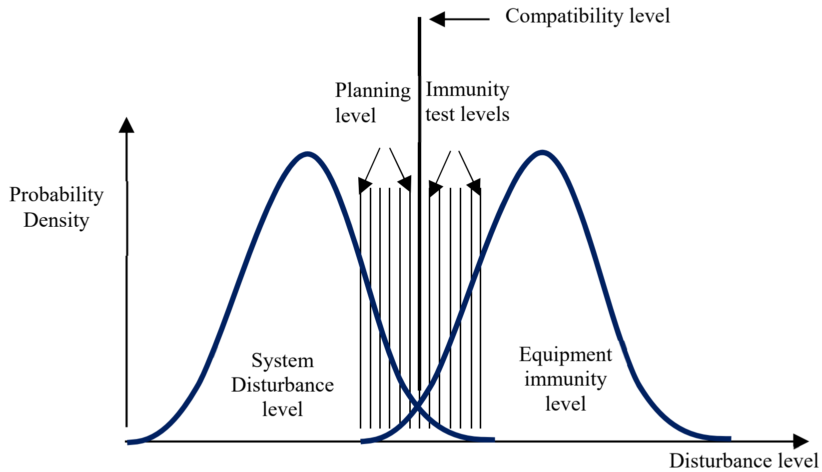


Figure 2.10 – Illustration of basic voltage quality concepts with time/location statistics covering the whole system [10]

In 2008, the IEC technical report [10] was commissioned to introduce improved allocation methods supplementing the existing methodologies in the 1996 version [39], which was adopted as a full standard AS/NZS 61000-3-6 [9] by the Australian National Regulatory Authorities. Subsequently, there have been various publications and literature attempting to put the IEC guidelines in practice and apply them to different situations. A number of leading academics, researchers and utility engineers have already pointed out that practical application of the outdated standard [9] and the new guidelines of technical report [10] can be very limited, ineffective in most cases, and may lead to underutilisation of harmonic absorption capability of network or a breach of planning levels. Nevertheless, in the absence of any satisfactory strategy, the technical report [10], which is based on a three-stage harmonic management approach, is the only one that provides sound principles and guidelines for harmonic allocations to major loads in a transmission system.

The IEC technical report [10] listed compatibility levels for individual harmonic voltages in LV and MV networks as a percentage of the fundamental component. However, it was highlighted above that compatibility levels are not defined in [10] for HV and EHV systems. Instead, indicative values of planning levels for harmonic voltages in MV, HV and EHV systems are included in [10] as shown in Table A.1 in Appendix A.

The IEC method [9, 10] consists of a three steps approach. Its practical application in harmonic allocation case studies is detailed in Chapter 3. The basis of [9] and [10] include:

- Second Summation Law with an acceptable cumulative probability of 95% (weekly value as defined in [10]) – The given probability allows for time, magnitude and phase diversity;

- One of the key principles of the IEC method [9, 10] is the use of the summation law to simplify calculations of net harmonic current from a number of distorting loads [41]. The summation law is adopted to account for the time, magnitude and phase diversity of several harmonic loads without completing a detailed harmonic study [41]. Further statistical analysis of the summation law is discussed in [42] and [43];

- A basic requirement of the summation law is that all customers, present and future, are allocated the harmonic emission rights such that when each customer generates to their full allowance, the maximum harmonic voltage will not exceed the planning level;

- Diversity is presented by the exponential summation law $V = \sqrt[\alpha h]{\sum_i V_i^{\alpha h}}$ value of α is dependent on the harmonic order *h*, in particular:

Table 2.3 – Alpha Constants Relative to Harmonic Order

h < 5	α = 1
5 ≤ h ≤10	α = 1.4
h > 10	α = 2

- Harmonic allocation increases with maximum demand (i.e. "agreed power" of the considered distorting installation – S_i);

- This methodology depends on network harmonic impedances and variation of network scenarios that also affect harmonic impedances. Therefore, modelling of network elements and selection of network configurations have major impacts on the effectiveness of the methodology;
- *Influence Coefficients* take into account the interactions among various harmonic producing loads in the meshed transmission systems. *Influence Coefficients* are related to elements of the system node impedance matrix for the harmonic order of interest. Calculation of the *Influence Coefficients* requires a complex computation process.

The IEC technical report includes both *Planning Levels* and the *Maximum Global Harmonic Contribution*, expressed as voltages at PCCs. Harmonic allocation to customers is expressed in voltage as a fair share of the *Maximum Global Harmonic Contribution* according to its agreed power relative to the total customer loads connected at the PCC. Similar to the IEEE standard, the IEC report also includes *Total Harmonic Voltage Distortion* for HV and EHV, $TDH_{V\ HV\text{-}EHV} = 3\%$.

The IEC method for transmission based allocations is particularly sensitive to *Influence Coefficients* ($K_{j,i}(h) = Z_{i,j}(h) / Z_{j,j}(h)$). *Influence Coefficients* were derived based on a similar application of the Thevenin Impedance, or Norton Admittance, to determine changes of harmonic voltages at remote buses due to harmonic current injection at a local load bus. For example, if harmonic currents from a load, e.g. Load 2, is injected into a local bus, e.g. Bus 2, it will lead to changes of harmonic voltages at other buses according to equation (2.25) below. *Influence Coefficients* are the resultant harmonic voltages at other buses, relative to 1 p.u. harmonic voltage source at the local bus. *Influence coefficients* are applied to the Sharing Planning Levels, equation (14) of the IEC technical report [10] to determine the *Maximum Allowable Global Harmonic Contribution* (G_{hm}) a busbar (m), which is used to allocate harmonics to all loads connected to the bus (m).

$$[\Delta \boldsymbol{V}(h)] = [\boldsymbol{Z}(h)].\begin{bmatrix} 0 \\ -I_2(h) \\ 0 \\ 0 \\ 0 \\ 0 \\ 0 \end{bmatrix} \tag{2.25}$$

Notes: The negative sign (-ve) indicates Load 2 injects harmonic current $I_2(h)$ into Bus 2

Ultimately, the IEC harmonic allocation methodology takes into account variations of harmonic current paths, concerning network scenarios, which are derived at harmonic frequencies rather than fundamental frequency like the *Short Circuit Ratio (SCR)* in the IEEE method. Therefore, the IEC method is considered more accurate at harmonic frequencies than the IEEE method.

Practical application of the [9, 10] guidelines given in the technical report is limited due to the following reasons:

(i) It has been proven in [44] that the approach given in [9, 10] fails to guarantee that harmonic voltages at each bus will be maintained below planning levels when all loads are utilising their full harmonic current allocations. This contradicts the basic requirements that planning levels are not to be exceeded in all cases;

(ii) Treatment for harmonic amplifications due to non-detuned capacitor banks and long transmission line capacitance has not been included in the guidelines of [9, 10];

(iii) Harmonic allocation procedures described in [10] heavily depend on the approximation of the total power (S_t) of all current and future installations for which emission limits are to be allocated. However, these procedures have not addressed how to deal with the uncertainty of future loads that are subjected to future network augmentation;

(iv) *Influence coefficients*, harmonic impedance and network scenarios are closely related to each other. In other words, changes in network scenarios will result in significant variation of harmonic impedances, and hence *influence coefficients*. Therefore, they must be calculated for all network scenarios, which can be very large for transmission systems;

(v) Harmonic currents and voltages are related to each other by harmonic impedance. The existing standard does not take changes of harmonic impedance, which can vary significantly with network scenarios, into account.

2.6.3 ESAA Method (One-Third Planning Level)

Since 1st January 2016, the Energy Supply Association of Australia (ESAA) became jointly owned and managed by the Australian Energy Council (AEC) and the Energy Networks Australia (ENA) and its board now consists of representatives of the Australian Energy Council and the Energy Networks Australia. This method is not documented in the literature, but it is rather considered as an industry practice by some ESAA member organisations. The one-third planning level method has been used by some Transmission Service Operators (TSOs) over the last 20 years. Fundamentally, it is based on the IEC standard, except for harmonic allocation methodology, which is simplified significantly and does not require the calculation of harmonic impedances. It adopts the same planning levels as recommended planning levels of the IEC standard for MV and HV networks. The allocation of one-third of planning voltages was based on an assumption that one-third of the planning level is for background (existing) harmonics, i.e. harmonic voltages due to injections from existing loads, and one-third is reserved for future loads. Therefore, one-third of planning levels can be allocated to a connecting load, irrespective of network configurations, load size and the number of loads at a PCC. Network harmonic impedances are not required for harmonic allocation, but for pre-connection assessment of voltages at PCC against planning levels. This method works relatively well for transmission networks in the past, due to its simplicity, which has very few harmonic sources and a high concentration of synchronous generators that absorb harmonics. However, it will likely lead to excessively harmonic voltages above planning levels for networks with high penetration of harmonic sources, especially where multiple sources share a common PCC, and under parallel resonance conditions.

2.6.4 IEEE-519 Standard

The Institute of Electrical and Electronics Engineers (IEEE) is an international professional association for electronic engineering and electrical engineering (and associated disciplines). IEEE is responsible for a wide range of standards, which exist almost in parallel with the IEC standards. In many instances, the IEEE standards compliment the IEC standards and vice versa. In some cases, they can be seen as competing with each other. Therefore, their application of these standards should be carefully considered depending on the issues and scenarios as contradictory requirements may potentially cause issues.

The IEEE-519: 1992 [45], which was revised extensively in 2014 [16], is another well-known alternative standard that also provides guidelines on harmonics. Similar to the IEC standard, this standard addresses a wide range of important topics in harmonic management, they include:

- Harmonic sources;
- Effects of harmonic distortion on various equipment and loads;
- Methods of harmonic analysis and measurements for compliance assessment;
- Methods of design for reactive compensation systems;
- Various techniques for mitigating and limiting harmonic emissions penetrating the power systems;
- Allocation of harmonic currents to loads are relative *Short Circuit Ratio* (*SCR*) at PCCs and it is independent of network harmonic impedances as the methodology does not require modelling of network impedances.

Principles of IEC and IEEE standards for harmonics are the same; they both guide the network authorities to manage harmonics in power systems. One common approach of both standards is to set individual limits for harmonic sources connected to the network. The practical application to this approach is very different between the two standards – the IEC standard depends on network impedances while the IEEE standard does not. In general, the IEEE standard aims at providing solutions to specific issues that have been identified from practical experiences, while the IEC standard provides relevant guidelines and methodologies to holistically address a wide range of harmonic problems in power systems. Therefore, the application of IEEE-519 [16, 45] often involves lookup tables that provide specific harmonic voltage limits for individual buses and harmonic current limits for individual customer installations. *Voltage Total Harmonic Distortion* (THD_V) limits at PCCs are specified for four voltage levels as shown in Table A.2, which is extracted from Table 1 of [16], in Appendix A.

Maximum harmonic current distortion in percent of maximum demand load current (I_L – fundamental frequency component) at the PCC under normal load operating conditions are specified for individual loads at three voltage levels: 120 V – 66 kV, 66 kV – 161 kV and >161 kV. Maximum harmonic current distortion increases as the ratio (I_{SC} / I_L) increases and decreases toward higher harmonic orders - I_{SC} is the maximum short circuit current at PCC. *Current Total Demand Distortion (TDD)* limits, which increases proportional to the increase of ratio *(I_{SC} / I_L)*, are also specified for each of the three voltage bands.

Current distortion limits for individual loads at three voltage levels are repeated in Table A.3, A.4 and A.5 in Appendix A to illustrate the relationship between current allocation and *Short Circuit Ratio (SCR)* at PCCs. These tables have been updated between the 1992 version [45] and the 2014 version [16]. Especially, a significant update for the voltage level above 161kV is shown in Table A.5. Multipliers have also been recommended in [16] for increases in harmonic current limits as shown in Table A.6.

The IEEE standard [16] implies that current distortion limits, as shown in Table A.3, A.4 and A.5, can be increased proportionally to the system strength (another interpretation of high short circuit power) of the network at a PCC. This standard specified both maximum individual current and voltage limits and their corresponding *Total Distortion (THD_V and TDD_I)* limits. It inherently assumes that there are diversity factors across the harmonic spectrum of each load, i.e. not all limits are reached at the same time. The *Total Demand Current Distortion (TDD_I)* limits based on different *Short Circuit Ratio* (*SCR*), which is expressed as I_{SC} / I_L, (defined below) at different voltage levels in Tables 2 - 4 of [16], are shown as Table A.3 – A.5 in Appendix A. It is necessary to reemphasise that *maximum harmonic current distortion limits expressed in the percentage of load current I_L* shown in these tables are only for odd harmonics. Limits for even harmonics are set to 25% of the odd harmonics.

> I_{SC}: Maximum short circuit current at PCC at the fundamental frequency.
>
> I_L: Maximum demand loads current, at a fundamental frequency, at the PCC under normal operating conditions.

It is noted that both I_{SC} and I_L are fundamental frequency quantities. I_{SC} is often derived from static network impedances at fundamental frequencies, ignoring changes of impedances caused by transformer on-load tap changers. The maximum *short circuit currents* (I_{SC}) at a PCC can be approximated with a high degree of accuracy based on the network impedance matrix. The three-phase fault current at a *bus* can be determined from the Thevenin Impedance, which is the diagonal element of the Z_{bus} matrix, e.g. Z_{11}, Z_{22},., etc.

The IEEE standard provides both individual current limits and TDD_I limits for loads connected to PCCs, with different (*SCR*), at different voltage levels. The limits are shown in Table 1 (*voltage distortion limits* at PCC) and Tables 2 – 4 (*current distortion limits* for loads) of [16] indicate that THD_V and TDD_I limits (for individual loads – *allocation limits*) represent the ultimate constraints of *Planning Levels* and *Harmonic Current Allocations* respectively. It essentially means that maximum individual current limits are allowed to be reached, but not all at the same time and the applicable TDD_I must not be exceeded. Therefore, multiple harmonic current sources connected to a PCC are allowed to have different harmonic emission spectrums as long as they comply with both individual limits as well as the TDD_I limits. Different PCCs in the network are expected to have different *SCRs*; therefore, according to the IEEE standard harmonic loads connected to a PCC with higher *SCR* are allocated with higher current emissions due to higher TDD_I limits.

Chapter 6 will examine the practical application of this method for harmonic allocations in transmission systems.

The IEEE allocation method does not require information of harmonic impedances, but fundamental frequency network impedance at PCC for the calculation of maximum network short circuit currents. It sets out voltage planning levels and corresponding THD_V, relative to voltage levels at PCCs. It also recommends harmonic current allocations and corresponding TDD_I, relative to the *SCR* and voltage levels at PCCs. However, it does not have any expression that describes the relationship between harmonic current allocations to, or harmonic emissions from, loads and harmonic voltage limits at PCCs. In other words, harmonic impedances, as well as a methodology for pre-connection compliance assessment, are not included in the standard. This raises the following questions: (i) how can the pre-connection harmonic compliance be assessed, given allocation is in currents and planning level is in voltages? and (ii) what are the effects of existing harmonic sources, i.e. background harmonics, on busbar voltages? Without answers to these questions, it would be very challenging for network utilities to exercise due diligence and fairness in harmonic management; and for load owners to demonstrate compliance under the rules. The relationship between the *SCR* and harmonic allocation as recommended in the IEEE-519 standard will be further examined in Chapter 6.

2.6.5 Former Australian Standard AS 2279.2

The Australian Standard AS 2279.2 – 1991 [20] is very basic, simple and easy to use. It was superseded by the AS/NZ 61000-3-6 [9], which is more or less the same as the IEC technical report [39]. It has been included in this thesis purely for comparison purposes of different harmonic allocation methodologies only. The philosophy of AS 2279.2 [20] is based on the assumption that there are only a few large non-linear loads in transmission systems and the majority of generators are synchronous machines. This assumption probably reflects the network status in 1991. Its recommended planning levels are based on the THD_V at PCCs, which are different for three voltage levels as per Table 1 of [20], repeated in this thesis as Table A.7 in Appendix A. Individual harmonic voltage allocation is given in percentages of harmonic voltage ratio to fundamental harmonic voltages. The individual harmonic voltage ratios for odd harmonics are twice as high as even harmonics. The Stage 2 Limits of this standard also indicates that additional harmonic loads may be connected depending on the *Short-Circuit Currents* (I_{SC}) at the PCC of interest. Based on the analysis of the IEEE method above, harmonic allocations referenced to fundamental frequency *Short-Circuit Currents* can also lead to unpredictable outcomes at harmonic frequencies. The practical application of this standard will be examined in details in Chapter 6.

Harmonic allocation for loads in the transmission system would fall under Stage 3 Limits of this standard. The allocation of harmonic currents is based on the load size or background harmonic measured in the system [41]. This method requires measurements of background harmonics to be assessed before allocating harmonics to new loads. It is the only method that makes use of measurements and could be considered as an early form of a "headroom" approach. This could make it a good candidate for dealing with all sorts of uncertainties. However, this requirement is not practical given that many utilities in the past did not have appropriate measurement equipment installed in their network. Now, almost 20 years later, some utilities still do not have adequate harmonic measurement equipment installed. Even if background harmonic measurements were available, they may not adequately represent scenarios, in which existing loads expand and take up their full allocations in the future. The assessment of background harmonics should be based on the assumption that all existing loads will, at some points, take up their full harmonic allocations. Furthermore, it does not take into account network harmonic impedances and resonance conditions that can cause harmonic voltages to exceed at PCCs and influences from other harmonic sources in the system. The practical application and suitability of this standard for harmonic allocation in transmission systems will be examined and compared against other methodologies in Chapter 6.

Table A.7 in Appendix A, extracted from Table 1 of AS 2279.2 [20], shows that each voltage level has only one limit for all odd harmonics, and one limit, which is half of the odd harmonic limit, for all even harmonics at each PCC. It appears that a contradiction exists within this standard. In particular, there are no diversity factors among different odd harmonics and the same intention applied for even harmonics. However, Table A.8 in Appendix A, repeated from Table 2 of AS 2279.2, includes some diversity factors for multiple converter-based types of equipment in an installation. It is unclear as to how these diversity factors were derived and if they are appropriate for converter loads in transmission systems given that the standard does not take into account harmonic impedances and resonance conditions.

The main difference between the IEC/TR 61000-3-6 and the AS 2279.2 is the time variation and diversity that were introduced to account for multiple types and operating modes of the non-linear loads with the system [41, 46]. Two important aspects are noted: (i) the former is an installation standard while the latter is an equipment standard; (ii) the former determines a "green-field" allocation with no consideration for the present state while the latter accounts for background.

For completeness practical application of the AS 2279.2 [20] and other standards will be further examined and analysed in the harmonic allocation case study in Chapter 6.

2.6.6 Comparison of Existing Harmonic Allocation Methodologies

From this point forward, unless specific names of standards are referred to, the IEC technical report IEC/TR 61000-3-6, Ed.2:2008 [10], IEEE-519:2014 [16] and ESAA (One-Third Planning Level) allocation method are referred to as IEC report, IEEE-519 standard and ESAA method respectively. There are many guidelines and standards available, some are more commonly known than others, e.g. IEC report and IEEE-519 standard. Existing harmonic allocation methodologies included in the comparison are: (i) IEC report, which was also adopted by the Australian and New Zealand Standards as AS/NZS IEC/TR 61000-3-6; (ii) IEEE-519; (iii) ESAA method adopted by its members; and (iv) AS 2279.2 (obsolete).

IEC report has been recognized as the most commonly applied standard by utilities [18, 19]. However, it is still not the most effective allocation method due to its deficiencies, which will be examined in Chapter 3. The IEC report method recommends voltage planning limits and allocates harmonic voltages to a load relative to its size and proportional to the maximum allowable global harmonic emission, which is limited by planning limits, at a PCC. Harmonic current allocation can be derived by dividing the allocated harmonic voltages by self-impedance of the respective PCC, e.g. $Z_{i,i}$ *(h)*. However, current allocation can lead to the harmonic voltage at the PCC exceeding planning levels if the self-impedance changes. The pros and cons between voltage and current allocations, i.e. E_{Uhi} and E_{Ihi} respectively, will be discussed in Chapter 8. The assessment of harmonic voltage performance at PCCs is based on the summation law with applicable exponential alpha constants. In short, the IEC method includes voltage planning limits at PCCs, voltage/current allocations to loads and pre-connection assessment at PCCs.

The IEEE-519 standard is considered as an alternative option to the IEC standard, but simpler and less commonly used outside of the United States (US) compared to the IEC. Its methodology includes setting voltage distortion limits (planning limits) at PCCs and harmonic current allocation to individual loads. It recommends one harmonic voltage limit, independent of harmonic order, and a THD_V for each of the three voltage levels, e.g. 1% for voltage > 161 kV and 1.5% for voltage level 69 kV ≤ V ≤ 161 kV as per Table 1 of [16]. For each voltage level, it allocates harmonic currents, in the percentage of maximum load current, according to the ratio between the *Maximum Short-Circuit Current* (I_{SC}) and the *Maximum Load Current* (I_L) at the PCC. However, it does not offer a methodology to perform a pre-connection assessment of harmonic voltages against planning levels at PCCs like to IEC method. It is unclear how pre-connection compliance can be assessed under the guidance of the IEEE standard.

The ESAA method is a less commonly known method outside Australia compared to the IEC and IEEE methods. It is not a standard, but rather a local industry practice that has been adopted by some ESAA member organisations in Australia to allocate harmonics to loads in transmission systems. Its voltage limits at PCCs are the same as the recommended planning levels of the IEC report, i.e. Table 2 of [10], shown in Appendix A as Table A.1. This method allows harmonic voltage allocation to loads at PCCs to be one-third (1/3) of the respective planning levels, regardless of network impedances, network scenarios and existing harmonic sources. The use of 1/3 in this manner makes no allowance for diversity. If one accepts the summation law for pre-connection assessment, this fraction could be increased to $(1/3)^{1/\alpha}$, (i.e. (1/3)^(1/alpha(α)). At alpha (α) equals 1.4 and 2.0, the fraction becomes 0.46 and 0.58 respectively which are significantly larger. In principle, connecting customers are only required to demonstrate that their harmonic emissions will not exceed 1/3 of the respective planning levels. It must be demonstrated both in the design report of the plant and laboratory measurements obtained during factory acceptance testing. In Australia, it is generally expected that network utilities are responsible for checking harmonic compliance – both pre-connection calculation and field measurements. The former is often based on the IEC methodology for calculating harmonic voltages at PCCs, i.e. summation law and alpha law. Overall, it can be said that the ESAA method is more or less the same as the IEC method in [10], except that individual harmonic voltage allocations are set at 1/3 of planning levels.

Although the AS 2279.2 [20] standard has been made obsolete, its harmonic allocation methodology is still included in this chapter for comparison purposes only. Its harmonic voltage allocation for loads is very simple, as shown in Table 1 of [20], repeated in Appendix A as Table A.7, and has no explicit references to network impedances nor harmonic current injection from existing loads. It does not provide a methodology to assess pre-connection compliance of harmonic voltages at PCCs either.

2.6.6.1 Planning Levels and Diversity

Harmonic allocation can be either in current or voltage terms as per [10]. It is important to emphasise that planning levels are often expressed as voltage limits at PCCs and harmonic allocation can be expressed in either voltage or current. Network utilities have the sole responsibility for ensuring that all network participants complying with their allocations. However, harmonic voltages at a PCC can be affected by changes of network impedances on either side, network or load side, of the PCC. Therefore, load owners often require access to relevant network data near the connection point to assess background harmonics from existing loads, harmonic voltage amplification and impedance attenuation effects. Similarly, network utilities also require relevant data of the proposed load to assess harmonic injection, amplification and impedance attenuation effects at the PCC. In other words, harmonic producing loads should be modelled both as a harmonic current source and an equivalent impedance connected to the network at the PCC.

A common requirement across the IEC/TR, IEEE-519, ESAA method (based on IEC standard), and the AS-2279.2 is that they all have recommended planning levels at PCCs; some depend on different voltage levels. However, they can be significantly different among different standards. Therefore, it is important to adopt only one set of planning limits, i.e. with either the IEC or the IEEE, but not mix across an interconnected network. For example, the Australian National Electricity Market (NEM) adopted only one planning standard, i.e. NER calls on the IEC-61000-3-6:2001 methodology.

The IEC report has included guidelines on how diversity factors, e.g. alpha (α) exponents, can be applied in the summation law. The Australian standard AS 2279.2 has recommended some diversity factors between 0.5 and 1, but only for multiple converter loads connected to the same PCC - not across the transmission network. The IEEE standard does not explicitly include details of diversity factors and how they can be applied in its allocation procedures. A summary of harmonic limits from different standards is listed in Table 2.4 below.

2.6.7 IEEE Standard versus IEC Report

The IEEE standard allocates harmonic currents based on to *SCRs,* at a fundamental frequency, at PCCs. On the other hand, the IEC technical report includes *Influence Coefficients* at harmonic frequencies in the assessment of *Global Harmonic Contribution* at PCCs. The *Influence Coefficients* at harmonic frequencies are directly related to harmonic impedances associated with the PCC of interest. The *Influence Coefficients* and *SCR* are both based on a similar principle, which takes into account the network impedances that influence currents flow resulting in variation of voltages at a PCC and remote buses. However, the former is based on network characteristics at harmonic frequencies, while the latter is founded on a fundamental frequency that can vary significantly at harmonic frequencies. Therefore, the application of *Influence Coefficients* in the IEC report for harmonic allocation is not directly comparable with the way in which *SCR* is used in the IEEE allocation.

Both IEEE standard and IEC report share similar outstanding issues, which are related to changes of network scenarios that affect network harmonic impedances and impact on harmonic allocation and voltage performance at PCCs. In a practical sense, the IEEE standard allows for scenarios in a manageable way – one only has to find the minimum *Short Circuit Ratio* (*SCR)* and this is usually known to planners. However, *SCR* may not always be the best indication for changes of harmonic impedances under different network scenarios. The problem for the IEC is considerably more challenging in practice as *Influence Coefficients* must be calculated, based on harmonic impedances, for every network scenarios. These issues have not been documented in harmonic planning and allocation of any existing standards to date. Therefore, the application of any existing standards will likely result in unexpected harmonic variations at PCCs due to changes in network scenarios. Methodical planning procedures will be discussed in Chapter 8 taking into account the network scenarios that affect the harmonic allocation and pre-connection compliance assessment.

Table 2.4 – Harmonic Planning Levels (Voltage Limits) from Various Harmonic Standards

	IEEE519		IEEE519		AS 2279	AS 2279	ENA Method	IEC 61000-3-6
	PCC	Load	PCC	Load	PCC	PCC	Load	PCC
h	V_{limit_PCC}	Max I_{h_Load}	V_{limit_PCC}	Max I_{h_Load}	V_{limit_PCC}	V_{limit_PCC}	Max V_{h_Load}	V_{limit_PCC}
	[> 161] kV		[69-161] kV		[22 - 66] kV	>= 110 kV	MV, HV & EHV	MV, HV & EHV
	I_{sc}/I_L <25		I_{sc}/I_L <20					
	%	%	%	%	%	%		%
2	1.0	N/A	1.5	N/A	1.0	0.5	0.467	1.400
3	1.0	1.000	1.5	2.000	2.0	1.0	0.667	2.000
4	1.0	0.250	1.5	0.500	1.0	0.5	0.267	0.800
5	1.0	1.000	1.5	2.000	2.0	1.0	0.667	2.000
6	1.0	0.250	1.5	0.500	1.0	0.5	0.133	0.400
7	1.0	1.000	1.5	2.000	2.0	1.0	0.667	2.000
8	1.0	0.250	1.5	0.500	1.0	0.5	0.133	0.400
9	1.0	1.000	1.5	2.000	2.0	1.0	0.333	1.000
10	1.0	0.250	1.5	0.500	1.0	0.5	0.117	0.350
11	1.0	0.500	1.5	1.000	2.0	1.0	0.500	1.500
12	1.0	0.125	1.5	0.250	1.0	0.5	0.106	0.318
13	1.0	0.500	1.5	1.000	2.0	1.0	0.500	1.500
14	1.0	0.125	1.5	0.250	1.0	0.5	0.099	0.296
15	1.0	0.500	1.5	1.000	2.0	1.0	0.100	0.300
16	1.0	0.125	1.5	0.250	1.0	0.5	0.093	0.279
17	1.0	0.380	1.5	0.750	2.0	1.0	0.400	1.200
18	1.0	0.095	1.5	0.188	1.0	0.5	0.089	0.266
19	1.0	0.380	1.5	0.750	2.0	1.0	0.358	1.074
20	1.0	0.095	1.5	0.188	1.0	0.5	0.085	0.255
21	1.0	0.380	1.5	0.750	2.0	1.0	0.067	0.200
22	1.0	0.095	1.5	0.188	1.0	0.5	0.082	0.246
23	1.0	0.150	1.5	0.300	2.0	1.0	0.296	0.887
24	1.0	0.038	1.5	0.075	1.0	0.5	0.080	0.239
25	1.0	0.150	1.5	0.300	2.0	1.0	0.272	0.816
THD_V	1.5		2.5					3.000
TDD_I		1.500		2.500				

2.6.8 The Australian National Electricity Rules (NER)

The Australian National Electricity Rules, published by the Australian Energy Market Commission (AEMC) [19], requires Transmission and Distribution Network Service Providers (DNSPs) to allocate harmonic emission limits to all harmonic sources connected to their network. In particular, clause S5.1a.6

of [19] stipulated that *the voltage* distortion level of *supply* should be less than the "compatibility levels" defined in Table 1 of *Australian Standard* AS/NZS 61000.3.6:2001 [9]. The rules expect Network Service Providers to establish planning levels (i.e. harmonic voltage distortion limits) at connection points within their network. In addition, Network Service Providers are responsible for managing the capability of networks and connection assets to absorb or mitigate harmonic voltage distortion according to the rules. The NER rules stipulate that the costs of managing or abating the impact of harmonic distortion in excess of the costs which would result from the application of an *Automatic Access Standard* are to be borne by those *Network Users* whose *facilities* cause the harmonic *voltage* distortion [32]. There has been significant improvements and updates incorporated in [10] since [9]. In 2012 Standards Australia and Standards New Zealand have already adopted the IEC/TR 61000-3-6, Ed 2:2008 in full and publish it as AS/NZS TR IEC 61000.3.6:2012. The AS/NZS 61000.3.6:2001 [9] is now officially suspended and hence the NER rules should refer to the new AS/NZS TR IEC 61000.3.6:2012 published by Joint Australia and New Zealand Standards committee, instead of calling up the older standard [9].

2.6.9 Australian Energy Market Operator (AEMO) Requirements

The approach of AEMO (Australian Energy Market Operator) for harmonic requirements is very much reinforcing requirements stated in the NER. Unlike National Grid in the UK, AEMO does not require mandatory harmonic compliance report from network utilities. AEMO often only requests utilities to investigate and report following an event that has already occurred, which has threatened the safe and reliable operation of the power system. Generally, as long as utilities can assure, they do not necessarily have to demonstrate, that they comply with the NER rules, any harmonic related issues between the network utilities and network participants are not within the purview of AEMO.

2.6.10 Efforts to Overcome Deficiencies in Existing Standards

Practical challenges of the existing standards have encouraged utilities and researchers to seek alternative methodologies to improve harmonic management. Despite significant efforts to date as detailed below, there is still no effective harmonic allocation method for loads in transmission systems.

Various standards and guidelines were developed in different regions and countries to suit their local network needs. Most countries have the freedom to develop their standards or adopt/modify standards developed by others to manage harmonics in their network. For example: English standard EN 50160 [47] and South African standard NRS 048-2:2003, Second edition [48]. Generally, these standards are referenced to either the IEC or IEEE standards with a wide range of variations to suit local network requirements.

In Australia, the concept of using Voltage Droop for Harmonic Current Allocation was introduced in [49] and [50] as an alternative methodology, which consists of a sound theoretical base and practical approach with minimum data requirements, for loads in MV and LV networks. The voltage droop concept is simple to use and only dependent on the agreed power of the distorted installation and the fault level of the assessed installation. However, its application, without further work, is not yet suitable for transmission systems.

Simulation case studies using a software program such as Sincal to find alternative methods to improve harmonic management in a large power system are covered in [51]. However, it lacks details in the simulation methodology, approach and assumptions. In particular, the methodologies are too simplistic and questionable.

Application of the guidelines provided in the Handbook [52] is limited to MV distribution systems with uniformly distributed loads and a simple radial topology [47]. It is based on a correction factor as developed in [54]. Methodologies described in [53, 54] attempted to detail the allocation process following IEC guidelines for different situations in MV systems only and are not suitable for transmission systems.

The harmonic allocation strategy developed for meshed HV network in [44] is to overcome the deficiencies in [9, 10]. This methodology is based on harmonic current allocation ($E_{Ihi} = k_h.S_i^{1/\alpha h}$), the harmonic current source instead of voltage, and the frequency-dependent allocation coefficients (k_h). The main focus of this approach is to determine the allocation coefficient k_h such that all harmonic bus voltages are limited to below Planning Level ($V_j(h) \leq L_h$) when all loads take their full harmonic currents allocations within 95% of the time. This allocation method results in smaller allocation at low order harmonics, hence constraint harmonic emission to below planning levels, and higher combined harmonic allocation at high order harmonics due to better utilisation of network harmonic absorption capability [44]. In contrast to this, the methodology in [10] does not fully utilise network harmonic absorption capacity at higher-order harmonics. A combination of methodologies in [44] and [55] may further improve the effectiveness of both methodologies but still would not meet the objectives of this research project.

The methodology in [56] mainly focused on the MV system. The fundamental approach is similar to that of [55], which uses allocation coefficient k_h. The allocation constant described in [56] can be calculated even if the data is incomplete. This is an advantage and it may be useful for the transmission system to minimise the amount of data required.

One of the main challenges in harmonic allocation in transmission systems is the accuracy of predicting future loads and network development. The size of loads at a bus in the transmission system can vary significantly from zero to thirty percent of fault level [55]. The allocation methodology described in [55] improves the efficiency and accuracy of the existing methods in [10]. Furthermore, the area-based allocation approach in [55] simplifies the amount of work required to identify every future load at each bus. It will be an area of load that consists of a number of similarly loaded buses. However, the assumption, which states future loads at buses can be determined with a reasonable degree of certainty, may not be justifiable. Furthermore, the assumption of a purely inductive network and ambiguous methodology used to assign loads to different areas constrain the effectiveness of this methodology.

The methodology described in the technical paper [17] is based on the guidelines of [9, 10], which is unsatisfactory due to the limitations of its practical application. It uses software tools of Power Factory and Matlab to assist in harmonic allocation procedures.

A case study of practical implementation of harmonic allocation to loads in transmission network in [57], which included the long transmission lines (200 km) in the model, showed that substantial capacitance associated with long transmission lines can lead to significant harmonic resonances. The model of transmission line in [57] incorporates distributed parameter equations, including series impedance, shunt admittance and skin effect. The entire primary transmission network was included in the case study model. The simulation results indicated that remote amplification is significant and cannot be neglected, hence network impedance attenuation also need to be seriously considered. The impact of resonances on the network harmonic impedance at the PCC is covered in [10]. However, the bus-to-bus amplifications, which are sharp and often occur over a short timeframe during normal transition phases (various network switching scenarios) of the operating system [57], have not been addressed by any literature known to date. The findings from this case study emphasise the significance of harmonic resonances and the need for better methodology and software tools for harmonic assessment.

2.7 Summary

A general overview of harmonics in power systems has been provided. Major transmission system equipment and harmonic sources directly relevant to the practical case studies conducted in this research project have been selectively identified and discussed. Harmonic models and computation methodologies relevant to transmission systems have also been identified as fundamental elements of sound harmonic management practices.

Relevant standards currently available for harmonic management have been extensively reviewed. Some of the challenges of implementation identified include inconsistent methodologies, unrealistic assumptions and impractical application, and most importantly the lack of a holistic approach to harmonic management. A common theme among the existing standards, e.g. the IEC report and IEEE standard, is that they rely on untested assumptions and futuristic scenarios. It was observed that in some cases where differences identified between estimated scenarios and actual measurements (or simulation results) are known, manual calibration was required for the existing methodologies. However, unless more reliable measurements can be collected to calibrate network models, there is no guarantee that the adjustments made for some specific cases can be applied to the majority of network scenarios. Common deficiencies are associated with the dependency on, and uncertainty of, network forecast (e.g. loads, generation and augmentation) as well as the lack of relevant measurements and data for network models. This thesis focuses on finding an alternative methodology that is less dependent on the uncertainty of futuristic scenarios.

The practical implementation of the Australian National Electricity Rules specifically requires Transmission Service Operator/Owner (TSOs) to set planning levels and be solely responsible for managing harmonic compliance at all buses in their network through harmonic allocation and connection assessment process. TSOs rely on existing standards and guidelines to meet their obligations under the NERs. The review of existing harmonic management practices, harmonic standards, NERs and requirements of AEMO to date confirms that methodologies of existing standards still have a number of deficiencies and are not effective for harmonic management of transmission systems. Practical application issues, especially for the most relevant IEC standard, need to be examined in detail and appropriate amendments identified to improve harmonic allocations in transmission systems.

Case studies on harmonic allocation have identified unique characteristics of some key network elements that only exist in transmission systems. Their combined harmonic impedances, which can significantly vary network harmonic impedances, heavily depend on the mix of network elements under different network scenarios. They must be comprehensively analysed and understood to achieve better harmonic management in transmission systems.

As an increasing number of large renewable generation sources are integrated into the transmission network, existing harmonic management practices need to be reviewed and updated with relevant improvements. An overarching strategic planning framework that includes harmonic allocation procedures, harmonic monitoring, report and pre-connection compliance assessment in transmission systems is required to further reinforce consistent harmonic management practices.

3 Deficiencies of the IEC Harmonic Allocation Method

3.1 Introduction

In this chapter, the application of the IEC harmonic allocation method in [10] for major loads in a realistic HV/EHV transmission system, similar to those in Australia, will be undertaken using a practical case study to identify deficiencies associated with the IEC standard. Detailed network models and harmonic power flows of the case study are based on CIGRE recommendations in [22] and computer modelling in [23] respectively. It is a complex multistage exercise, which requires, besides application of the recommendations, constant reconsideration of network models, network capabilities, and reality checks of the results. The IEC guidelines fundamentally assume that the network configuration is static and the values of the α exponents used in the second summation law are optimised for 95th percentile non-exceeding probabilities. The assumption also relies on the diversity of loads, and magnitude and phase angle variations of harmonic voltages derived from MV and LV distribution systems [42].

HV/EHV Transmission systems inherently consist of highly meshed networks coupled with large loads and long transmissions lines. Transmission network configurations and load characteristics typically differ significantly from MV and LV systems. Large complex loads, long transmission lines and large capacitor banks are typically unique to transmission systems. Generally, the IEC's allocation method [10] for major transmission systems often result in under allocation, except for some over-allocation cases that caused planning levels to be exceeded [44]. Under-allocation will impose additional costs to load owners to lower their harmonic emissions unnecessarily. On the other hand, over-allocation will require utilities to install additional harmonic filters to mitigate excessive harmonics in the network.

The investigation method used in this thesis relies on key elements – realistic case study network, harmonic models, harmonic allocation methodology and analysis of harmonic performance.

3.2 Harmonic Case Study Network

In order to gather results, analyse and formulate recommendations for harmonic management, the research relies on the practical relevance of a suitable case study network. A 7-bus 132 kV network, as shown in Figure 3.1, was developed to adequately represent a realistic network with the complexities of a meshed transmission system. This network is based on a reduced area of a real network that has long transmission lines, meshed network, large capacitor banks, large synchronous generators, large loads, and a static VAr compensator (SVC), which is a well-known harmonic source [5, 23]. It represents many of the features found in the Transmission Network of the state of Queensland in Australia. This network was chosen for practical case studies based on the findings below obtained from results of research tasks, literature review and simulation studies undertaken during this research project. In this thesis, inter-harmonic impedances have been ignored as the current case study network does not contain multiple power-electronic converter based sources such as solar and wind converters that potentially generate inter-harmonic currents. SVC is not known for inter-harmonic emission.

(i) Synchronously rotating machines, including synchronous motors, generators and condensers, absorb harmonic power [1], hence contribute significantly to network absorption capability;

(ii) The combination of large capacitor banks, long transmission lines, large reactors and power transformers can result in multiple parallel and series resonances at various harmonic frequencies. These resonances can be sensitive to network configurations. Depending on magnitudes and phase angles of (parallel and series) resonant impedances, the resultant harmonic voltages at network buses can be significantly increased or decreased;

(iii) Large energy consumption loads, including bulk distribution loads and large industrial loads at PCCs, can effectively absorb harmonic powers and attenuate impedances that in turn can help to lower harmonic voltages in the network, especially at PCCs.

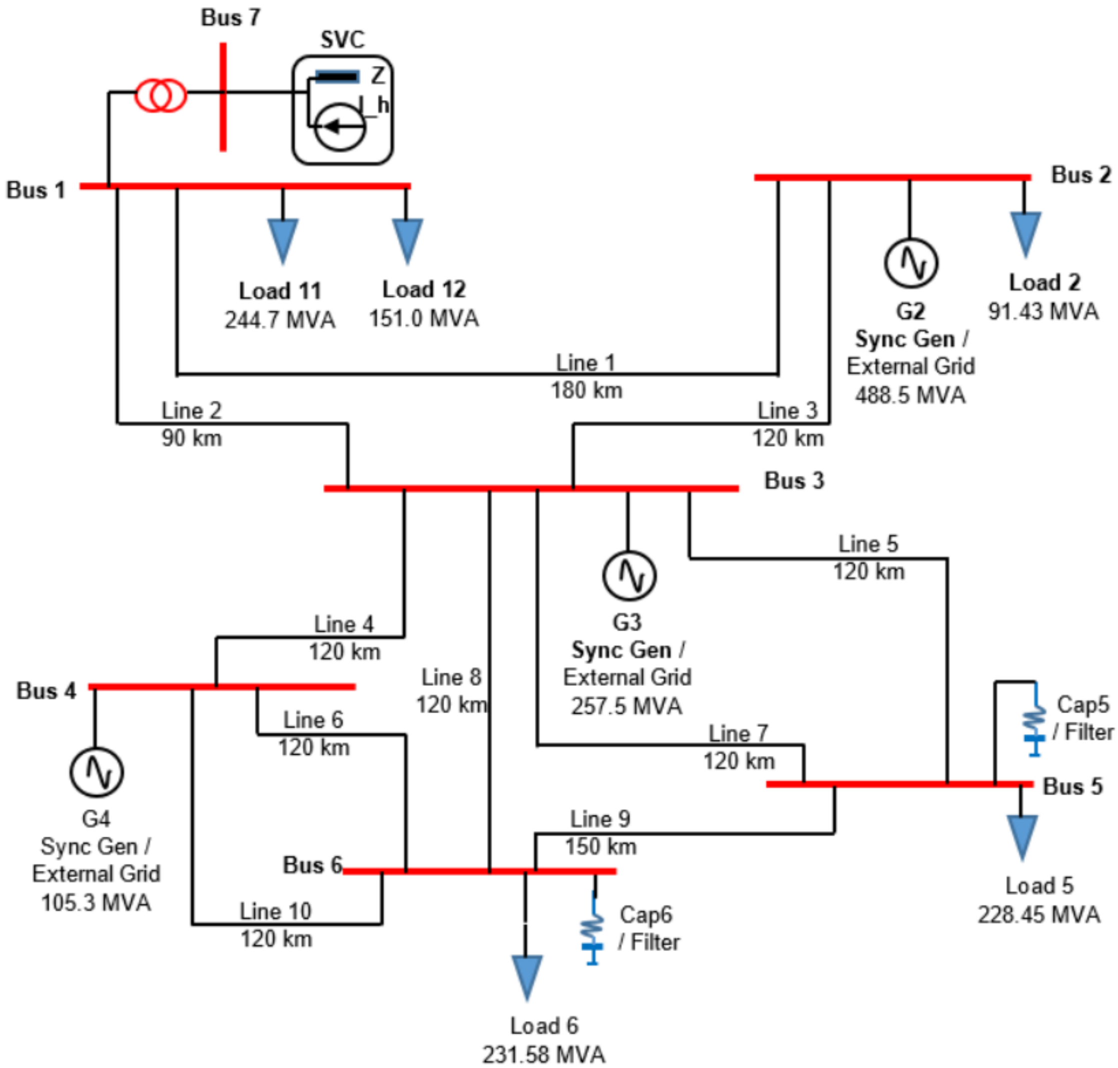


Figure 3.1 – Case Study 7-Bus 132 kV Transmission Network

Parameters of the Figure 3.1 network are summarised below:

- Table 3.1 – Transmission line parameters,
- Table 3.2 – Synchronous generator parameters,

- Table 3.3 – Load Parameters,
- Table 3.4 – Shunt capacitor parameters,
- Table 3.5 – Static VAr Compensator (SVC) parameters.

Table 3.1 – Harmonic Case Study Network – Transmission Line Parameters

Transmission Line Parameters						
Lines Description	**From Bus**	**To Bus**	**R**	**X**	**L**	**C**
			Ohm	**Ohm**	**km**	**µF/km**
Line 1	1	2	7.183	55.744	180	0.0118
Line 2	1	3	4.442	33.425	90	0.0100
Line 3	2	3	5.923	44.566	120	0.0100
Line 4	3	4	5.923	44.566	120	0.0100
Line 5	3	5	4.442	33.425	90	0.0100
Line 6	4	6	11.415	46.788	120	0.0095
Line 7	3	5	11.415	46.788	120	0.0095
Line 8	3	8	5.923	44.566	120	0.0100
Line 9	5	6	5.923	44.566	150	0.0100
Line 10	4	6	5.923	44.566	120	0.0100

Table 3.2 – Harmonic Case Study Network – Synchronous Generator Parameters

Generator Parameters						
Connection Point	**Description**		**Active Power**	**Reactive Power**	**Apparent Power**	**X_d''**
		Generator Type	**MW**	**MVAr**	**MVA**	**p.u.**
Bus 2	G2	Synchronous Machine	480.00	90.80	488.51	0.147
Bus 3	G3	Synchronous Machine	250.00	61.80	257.53	0.235
Bus 4	G4	Synchronous Machine	103.90	105.26	112.32	0.150

Table 3.3 – Harmonic Case Study Network – Load Parameters

Load Parameters				
Connection Point	**Description**	**Active Power**	**Reactive Power**	**Apparent Power**
		MW	**MVAr**	**MVA**
Bus 1	Load 11	232.5	76.4	244.73
	Load 12	131.0	75.1	151.04
Bus 2	Load 2	86.85	28.56	91.43
Bus 5	Load 5	217.3	71.32	228.70
Bus 6	Load 6	220	72.3	231.58

Table 3.4 – Harmonic Case Study Network – Shunt Capacitors

Shunt Capacitors						
Connection Point	Description	Volt	C	L	R	Q
		kV	μF	mH	Ohm	MVAr
Bus 5	Cap 5	132	5.138	123.25	3.098	30
Bus 6	Cap 6	132	5.138	123.25	3.098	30

Table 3.5 – Harmonic Case Study Network – SVC Parameters

SVC Parameters			
SVC Elements	**Connection Type**	**Value**	
Thyristor Control Reactor (TCR)	Delta	L	15.85 (mH)
Thyristor Switch Capacitor (TSC)	Delta	C	532.3 (μF)
		L	0.94 (mH)
5th Harmonic Filter	Star	C	209.9 (μF)
		L	1.95 mH
7th Harmonic Filter	Star	C	142.8 μF
		L	1.46 mH
11th Harmonic Filter	Star	C	144.6 μF
		L	0.58 mH
Transformer	Nominal HV Voltage	V_{HV}	132 kV
	Nominal LV Voltage	V_{LV}	14.1 kV
	Nominal Power	S	150 MVA
	Impedance	Z_0	11%

3.3 Modelling of Case Study Network

According to [40], the IEC's method recommends harmonic study up to 50th harmonic as a baseline and up to 100th harmonic for the presence of multi-pulse converters, e.g. multi-level STATCOMs. Harmonic modelling is one of the most critical and challenging tasks in harmonic management. It is difficult to obtain a comprehensive network model suitable for harmonic studies up to 100th harmonic due to the complexities of transmission lines, e.g. details of tower configurations, and detailed models of multi-level power electronic converter modules. Most utilities in Australia are not able to verify if their network models accurately represent the actual network's characteristics at such high frequencies and thus more comprehensive network harmonic models are required. However, measurements of network voltages and currents at high frequencies have practical challenges due to the frequency response characteristics of instrument transformers at high voltage and frequencies [1]. More research, simulations and better high voltage instruments systems, e.g. fibre-optic instrument transformers, are required for high voltage network harmonic models at high frequencies.

The CIGRE/CIRED joint working group recommendations in [22] suggest the 20th harmonic order as the limit for harmonic impedance calculations [40]. This thesis focuses on the allocation of major harmonic sources, which produce significant harmonics at lower frequency spectrums, in transmission systems. As a compromise, all harmonic investigations carried out in this thesis are performed to the 25th harmonic due to the low confidence of modelling accuracy at frequencies beyond the 25th harmonic. Throughout this project, inter-harmonics and intra-harmonics, which often occur at high frequencies, have been excluded from the modelling.

For harmonic allocation purposes, the distribution of balanced harmonic currents in the network is the main interest. Hence, the network asymmetries are not in the scope of this project and the study can be performed with single-phase system representation using the positive sequence system model. However, it is assumed that triplen harmonics will still be present in all case studies used in this thesis to allow for unintended unbalance of network scenarios and harmonic sources, which are caused by the equipment of network participants. In practice, triplen harmonics, although very low, do exist in operational transmission networks as they cannot be perfectly balanced. In some cases, triplen harmonics can be very significant due to unbalance loads or single-phase control of SVC or STATCOM. Triplen and even harmonics up to the 25th order are treated in the same manner as any other harmonics. In addition, interactions between different harmonic frequencies and cross-coupling of different frequencies across a power electronic converter [58, 59, 60] are omitted due to the lack of relevant information to accurately model their effects in harmonic allocation studies.

Assessment of network harmonic impedance is a crucial step that has to be undertaken with a high degree of accuracy. However, it is a very difficult and complex task due to a lack of comprehensive knowledge of practical network characteristics as its impedance varies continuously with loads, network configurations and operating system conditions.

Network element models for the IEC method were initially proposed by CIGRE WG 36.05 [61]. Since then, the Joint Working Group CC02 (CIGRE 36.5 and CIRED 2) has published further guidelines for assessing network harmonic impedance [22]. The new guidelines include improvements of a generator, transformer, line or cable, and load models, as well as, taking into account the considered network, load importance, analytical and computation tools. It has also suggested to include customer equipment in the assessment of network impedance. In particular, harmonic impedances seen from primary transmission system buses can be greatly influenced by the degree of representation of the distribution system and the consumer loads fed radially from each busbar [1]. However, this is not easy to achieve in practice due to asset ownership boundary issues that restrict the availability of customer equipment data beyond the PCCs. Generally, the majority of loads fed from distribution feeders is located behind bulk supply transformers. Therefore, to calculate the harmonic impedances seen from the high voltage primary transmission side it may be sufficient just to use a discrete model of the composite effect of many loads and distribution system lines and transformers at the high voltage side of the main distribution transformers [1]. This research project does not include details of customer equipment models beyond/behind the PCCs. All network elements used in the case studies of this research project are modelled following the CIGRE guideline [22].

3.3.1 Generator Model

Detailed model of synchronous generators G2, G3 and G4 used in the case study network in Figure 3.1 is described in Appendix B – Section B.1. Graphical representation of synchronous generator harmonic impedance model is represented in Figure 3.2. Magnitude and angle of G2 synchronous generator harmonic impedance, $Z_{SyncGen}(h)$, appear as linear inductive impedance over the harmonic frequency spectrum as shown in Figure B.2 (a) and (b) respectively.

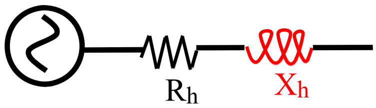


Figure 3.2 – Synchronous Generator Harmonic Impedance Model

Generally, under balanced network conditions, synchronous generators (rotating machines) provide a low impedance path for harmonics due to its sub-transient reactance X_d". Therefore, its impedance must be included in the network model. On the other hand, asynchronous generators or inverter-based generators, such as wind and solar plants, do not have the same ability (negligible) to absorb harmonics. They should be modelled as harmonic voltage or current sources due to power electronic circuitries [3–7]. Harmonic impedances of these plants, which comprises MV cables, transformers and filter capacitors, should also be included in the network harmonic models where practical to do so. However, they have been omitted from the modelling here to minimise the complexities of calculations. Often, these components are ignored during the initial harmonic allocation process (connection enquiry assessment) as the plant is not yet designed or built.

3.3.2 Transformer

A transformer is located in the case study network of Figure 3.1 between Bus 1 and Bus 7. Its harmonic impedance is modelled as in Appendix B – Section B.2. Graphical representation of transformer harmonic impedance model is represented in Figure 3.3. The transformer model in this case study was for the SVC, therefore the reduced transformer ratio n = 1, i.e. transformer is on its nominal tap and the tap changer is not included in the calculation. However, $n \neq 1$ will be applicable for transmission system transformers fitted with a tap changer. The transformer harmonic admittance model is illustrated in Figure B.4. Similar to the synchronous generator model, harmonic impedance magnitude and angle of the case study network transformer, $Z_{Tfmr}(h)$, *also* appear as inductive impedance changes linearly with harmonic frequencies, as shown in Figure B.5 (a) and (b) respectively.

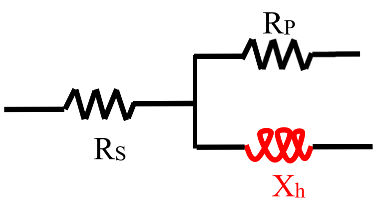


Figure 3.3 – Transformer Harmonic Impedance Model

3.3.3 Transmission Line

Transmission lines, which are critical network elements, underpin the unique characteristics of transmission systems. Details of the transmission line model are shown in Appendix B – Section B.3 and its harmonic admittance model shown in Figure 3.4. The transmission line model includes series impedance and shunt admittance. Its series impedance magnitude, angle and admittance appear as multiple resonances over the frequency spectrum as shown in Figure B.7 (a), (b) and (c) respectively. Transmission line impedance/admittance contribute to resonance conditions in transmission networks. Therefore, accurate modelling of transmission lines is very important for harmonic studies.

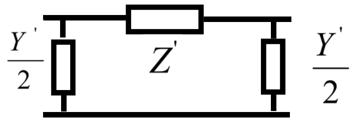


Figure 3.4 – Transmission Line Harmonic Admittance Model

3.3.4 Aggregated Loads

CIGRE guideline-recommended three load models as detailed in Appendix B – Section B.4. The linear load model used to represent Loads 2, 5, 6, 11 and 12 in Figure 3.1 is the "CIGRE Load Impedance Model" as shown in Figure 3.5. Characteristics of three CIGRE recommended load models, including magnitudes and angles, are shown in Figure B.11 (a) and (b) respectively.

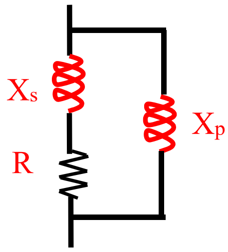


Figure 3.5 – CIGRE Load Impedance Model

3.3.5 Shunt Capacitors and Passive Harmonic Filters

Models of shunt capacitors, including harmonic filters and voltage support capacitor banks, are detailed in Appendix B – Section B.5. A harmonic filter with a parallel damping resistor, which is sometimes used in transmission systems, is depicted in Figure 3.6. Voltage support capacitor banks, which often do not require a damping resistor, is illustrated in Figure 3.7. Characteristics of different shunt capacitors, including harmonic impedance magnitudes and angles, are presented in Figure B.14 (a) and (b) respectively.

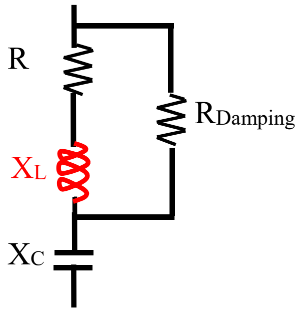


Figure 3.6 – Harmonic Filter with Damping Resistor Impedance model

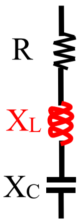


Figure 3.7 – Voltage Support Capacitor Bank Impedance model

3.3.6 Static VAr Compensator

SVC is considered as a power electronic system, which is difficult to model because besides being a harmonic source, its elements do not represent a constant R, L, C configuration and their overall characteristic cannot fit the linear harmonic equivalent model. However, their effective harmonic impedances need to be considered when the power ratings are relatively high.

Here the SVC is modelled both as a network harmonic impedance and a harmonic current source using realistic component values obtained from an operational SVC in the Queensland transmission system. It consists of:

- Thyristor Control Reactor (TCR 1);
- Thyristor Switch Capacitor (TSC 1);
- Fifth Harmonic Filter (STF 1);
- Seventh harmonic filter (STF 2);
- Eleventh harmonic filter (STF 3).

Both TCR and TSC are connected in delta and the control system operates in balanced three-phase mode (i.e. no single-phase control), therefore, all balanced triplen harmonics are trapped within the TCR delta circuit. The simplified single line diagram of the SVC is shown in Figure 3.8 below.

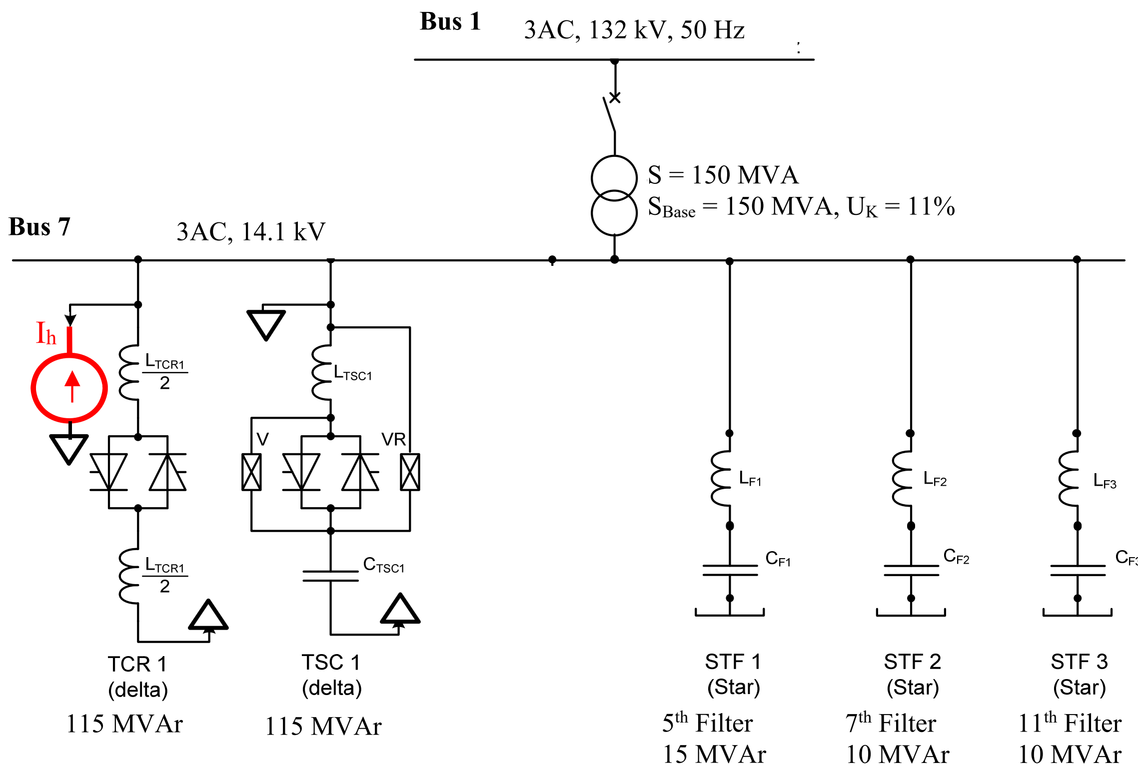


Figure 3.8 – SVC Single Line Diagram

The SVC harmonic impedance model consists of TCR reactors, TSC capacitor banks with series inrush reactors, harmonic filters 5th, 7th and 11th, and 132/14.1kV coupling transformer between Bus 1 and Bus 7. The TCR is modelled both as a harmonic current source and a linear inductive reactance. The formation of SVC's harmonic impedance is shown below. The harmonic current source only exists in the TCR and is shown as part of the delta circuit. The detailed SVC model is expressed in a number of equations below based on the extensive practical experience of the author working with SVCs and STATCOMs.

Resistive components in capacitor banks (TSC and harmonic filters) and reactors (TCR, TSC and harmonic filter) are very small and often omitted in SVC impedance calculations.

$$Z_{SVC\_Bus7} = \frac{1}{Y_{SVC\_Bus7}} = \frac{1}{Y_{TCR1}+Y_{TSC1}+Y_{Filter\_5}+Y_{Filter\_7}+Y_{Filter\_11}} \tag{3.1}$$

TCR admittance (delta connection): A factor of 1/3 is applied to the TCR impedance due to the delta connection of TCR.

$$Y_{TCR1} = \frac{1}{Z_{TCR1}} = \frac{1}{\frac{j.\omega_0.h.L_{TCR1}}{3}} = \frac{3}{j.\omega_0.h.L_{TCR1}} \tag{3.2}$$

TSC admittance (delta connection): A factor of 1/3 is applied to the TSC impedance due to the delta connection of TSC.

$$Y_{TSC1} = \frac{1}{Z_{TSC1}} = \frac{1}{\left(\frac{1}{3}\right).\left(\frac{1}{j.\omega_0.h.C_{TSC1}} + j.\omega_0.h.L_{TSC1}\right)} \tag{3.3}$$

$$Y_{TSC1} = \frac{1}{Z_{TSC1}} = \frac{3}{\left(\frac{1}{j.\omega_0.h.C_{TSC1}} + j.\omega_0.h.L_{TSC1}\right)}$$

5^{th} harmonic filter admittance (star connection):

$$Y_{Filter\_5} = \frac{1}{Z_{Filter\_5}} = \frac{1}{\left(\frac{1}{j.\omega_0.h.C_{Filter\_5}} + j.\omega_0.h.L_{Filter\_5}\right)} \tag{3.4}$$

7^{th} harmonic filter admittance (star connection):

$$Y_{Filter\_7} = \frac{1}{Z_{Filter\_7}} = \frac{1}{\left(\frac{1}{j.\omega_0.h.C_{Filter\_7}} + j.\omega_0.h.L_{Filter\_7}\right)} \tag{3.5}$$

11^{th} harmonic filter admittance (star connection):

$$Y_{Filter\_11} = \frac{1}{Z_{Filter\_11}} = \frac{1}{\left(\frac{1}{j.\omega_0.h.C_{Filter\_11}} + j.\omega_0.h.L_{Filter\_11}\right)} \tag{3.6}$$

where:

$\omega_0 = 2 \times \pi \times f_0$;

$f_0 = 50$ Hz;

h: Harmonic order;

L_{TCR1}, L_{TSC1}: Inductance of TCR1 and TSC1 respectively;

$L_{Filter5}$, L_{Filter_7}, L_{Filter_11}: Inductance of Filter 5 (5^{th} harmonic filter), Filter 7 (7^{th} harmonic filter) and Filter 11 (11^{th} harmonic filter) respectively;

C_{TSC1}, $C_{Filter5}$, L_{Filter_7}, L_{Filter_11}: Capacitance of TSC1, Filter 5 (5^{th} harmonic filter), Filter 7 (7^{th} harmonic filter) and Filter 11 (11^{th} harmonic filter) respectively;

Z_{SVC_Bus7}, Y_{SVC_Bus7}: SVC impedance and admittance measured at bus 7 respectively;

Z_{TCR1},Y_{TCR1}: TCR1 impedance and admittance measured at bus 7 respectively;

Z_{TSC1},Y_{TSC1}: TSC1 impedance and admittance measured at bus 7 respectively;

Z_{Filter_5}, Y_{Filter_5}: Filter 5 (5^{th} harmonic filter) impedance and admittance measured at bus 7 respectively;

Z_{Filter_7},Y_{Filter_7}: Filter 7 (7^{th} harmonic filter) impedance and admittance measured at bus 7 respectively;

Z_{Filter_11},Y_{Filter_11}: Filter 11 (11^{th} harmonic filter) impedance and admittance measured at bus 7 respectively.

3.3.7 Network Harmonic Admittance and Harmonic Impedance Matrices

The 7-bus network harmonic admittance and impedance matrices are constructed for harmonic injection and evaluation of harmonic voltages at all buses in the network.

$$[Y(h)] = \begin{bmatrix} Y_{1,1}(h) & Y_{1,2}(h) & \dots & Y_{1,7}(h) \\ Y_{2,1}(h) & Y_{2,2}(h) & \dots & Y_{2,7}(h) \\ \vdots & \vdots & \ddots & \vdots \\ Y_{7,1}(h) & Y_{7,2}(h) & \dots & Y_{7,7}(h) \end{bmatrix} \tag{3.7}$$

Detailed model of self and mutual admittances are calculated using a MATLAB program. Several MATLAB programs were written during this project to assist with a wide range of complex tasks involved in harmonic allocations. One of these MATLAB programs, which was used to calculate harmonic admittances, impedances and voltages of the case study network in this chapter, is shown in Sections C.1 to C.7.

3.4 Practical Harmonic Allocation Based on the IEC/TR 61000-3-6

The underlining principle of the IEC report allocation methodology is the second summation law (exponent α varying with the harmonic order h), refer to Table 2.3 and discussions in Chapter 2. Accordingly, if the individual voltage sources have 95th percentile voltage values of magnitude $V_i(h)$, the 95th percentile of their combined voltage can be determined as:

$$V(h) = \sqrt[\alpha]{\sum_{i=1}^{n} V(h)_i^{\alpha}} \tag{3.8}$$

a) The IEC report allocation methodology comprises three stages as discussed in Chapter 2 and summarised again here for clarity:

Stage 1. Simplified evaluation;

Stage 2. Emission limits relative to system characteristics; and

Stage 3. Acceptance of higher emissions for temporary conditions.

b) Allocations using Stage 2 will be the most applicable in the allocation planning process, and consists of three steps as follows:

c) **Step 1**: Find *Influence Coefficient* ($K_{j\text{-}i}(h)$), to calculate the MVA capacity of the PCC (Point of Common Coupling). At each harmonic order h, calculate the influence coefficients $K_{j\text{-}i}(h)$ which is the harmonic voltage of order h caused at node i when 1 p.u. a harmonic voltage of order h is applied at node j with all harmonic currents at other nodes being set to zero. In other words, if harmonic current $E_{I\,j}(h)$ is injected at node j until voltage at node j reaches 1 p.u ($V_j(h) = 1 = Z_{j,i}(h) * E_{Ij}(h)$, then $E_{Ij}(h) = 1 / Z_{j,j}(h)$) while harmonic currents at other nodes are set to zero. The *influence coefficient* ($K_{j\text{-}i}(h)$) is the voltage measured at node i ($V_i(h) = Z_{i,\,j}(h).\ E_{I\,j}(h)$) due to the harmonic current $E_{I\,j}(h)$ injected at node j. Therefore, at each harmonic order h, the influence coefficients can be simply defined by:

(i) $$K_{j-i}(h) = V_{j-i}(h) = \frac{Z_{(i,\ j)}(h)}{Z_{(j,\ j)}(h)} \tag{3.9}$$

(ii) $K_{j\text{-}i}(h)$ or $V_{j\text{-}i}(h)$: *Influence coefficient,* i.e. harmonic voltage, measured or calculated at node i when 1 p.u. voltage is applied at node j.

(iii) Where $i = j$, $K_{i\text{-}i}(h) = 1$, e.g. $K_{1\text{-}1}(h) = K_{2\text{-}2}(h) = .. K_{i\text{-}i}(h) = K_{j\text{-}j}(h) = 1$.

(iv) $Z_{i,j}(h) = Z_{j,i}(h)$: Harmonic impedance between node i and j, e.g. transmission line series impedance.

(v) $Z_{j,j}(h)$: Harmonic impedance at node j where the harmonic current is injected.

(vi) Complex *Influence coefficients*, as shown in equation (3.9), might be used in steady-state deterministic calculations without diversity. It is not used in this thesis and does not follow an IEC approach either.

(vii) Absolute *Influence coefficients*, as shown in equation (3.10), has been used throughout this thesis as the summation law has been applied to account for phase diversity.

(viii) $$K_{j-i}(h) = V_{j-i}(h) = \left|\frac{Z_{(i,\ j)}(h)}{Z_{(j,\ j)}(h)}\right| \tag{3.10}$$

d) **Step 2**: Use *influence coefficient* ($K_{j-i}(h)$) to calculate the permissible harmonic voltage limit at its point of common coupling (PCC).

e) **Step 3**: Calculate the harmonic voltage or current limits based on the permissible harmonic voltage from Step 2 and network harmonic impedance $Z_{i\,i}(h)$.

The IEC second summation law and the power-law make use of the *influence coefficient* ($K_{j-i}(h)$) and the exponent α constants. The influence coefficients essentially describe the characteristics of a network scenario through the expression of harmonic impedances as per (3.10). The values of exponent α for the 95th percentiles were determined for various magnitudes of uniformly random amplitude and phase. The results of case studies conducted in this research project indicated that application of the IEC second summation law and the exponent α in its current forms may not be optimal for a realistic transmission system with fewer but larger loads injecting harmonics with both phase and amplitudes vary with network scenarios, time and frequencies. However, in the absence of any better exponent α for transmission systems, the existing α values are the only option when applying the IEC summation law.

Major loads in transmission systems do not normally have defined harmonic current amplitudes or phase angles. As a result, harmonic voltages measured from the real system could be worse or better than the voltages calculated using the existing second summation law and associated exponent α in the IEC technical report [10]. Some planning engineers, e.g. author of [17], in the electricity supply industry have recommended options to further improve the effectiveness of the IEC methodology: (i) one potential option is to optimise the values of exponent α for transmission systems with large complex loads; (ii) another is to adjust harmonic allocation to take into account of individual load's current injection phase angle(s) and network impedances at the PCC to ensure that planning levels will not be exceeded. These are novel ideas, which should be investigated thoroughly before being implemented, but are not within the scope of this thesis.

The methodology for sharing planning levels between busbars in meshed HV-EHV systems is defined by Equation 14 of the IEC technical report [10] and further expanded in Appendix D of the same document. It is repeated here as (3.11) below.

The method in Annex D of the IEC TR 61000.3.6 that was used in the thesis is complex and computationally intensive, but this thesis does not aim to simplify the computation methodology. The main focus of the thesis is to clarify the practical application and improve the effectiveness and utilisation of the existing method in Annex D of the IEC TR 61000-3-6:2008, Edition 2. Chapter 5 demonstrates the main purpose of the thesis. Simplification of a computation methodology was deemed to be low value as computer added software, e.g. MATLAB codes designed in the thesis, can easily accommodate and overcome any computational task.

The *global contribution* of harmonic emission at bus *m* is defined as:

$$G_m(h) \leq \sqrt[\alpha]{\frac{S_{tm}}{(K^{\alpha}_{1-m}(h)\times S_{t1})+(K^{\alpha}_{2-m}(h)\times S_{t2})+..+(K^{\alpha}_{n-m}(h)\times S_{tn})}} \times L_{HV}(h) \quad (3.11)$$

It is noted that the same condition for all busbars needs to be evaluated to find the minimum *global contribution* at bus *m*, G_{hBm}, that will ensure harmonic voltage levels at bus *m* are not exceeded. For a system of *n* buses, there are *n* conditions required to be satisfied for each busbar, e.g. for Bus 1 (*B1*):

(i) Condition 1:

$$G_{B1}(h) \leq \sqrt[\alpha]{\frac{S_{t1}}{(S_{t1})+(K^{\alpha}_{2-1}(h)\times S_{t2})+..+(K^{\alpha}_{n-1}(h)\times S_{tn})}} \times L_{HV}(h) \quad (3.12)$$

(ii) Condition 2:

$$G_{B1}(h) \leq \sqrt[\alpha]{\frac{S_{t1}}{(K^{\alpha}_{1-2}(h)\times S_{t1})+(S_{t2})+..+(K^{\alpha}_{n-2}(h)\times S_{tn})}} \times L_{HV}(h) \quad (3.13)$$

…

(iii) Condition *n*:

$$G_{B1}(h) \leq \sqrt[\alpha]{\frac{S_{t1}}{(K^{\alpha}_{1-n}(h)\times S_{t1})+(K^{\alpha}_{2-n}\times S_{t2})+..+(S_{tn})}} \times L_{HV}(h) \quad (3.14)$$

The maximum *global harmonic contribution* at bus *B1* (i.e. $G_{B1}(h)$) is the lowest value of all *n* cases of $G_{B1}(h)$ will be selected to calculate the individual emission limits at that bus. This method primarily aims at ensuring that planning levels will not be exceeded when all distorting loads take up their full allocation.

The individual emission limit for the load (S_i) connected to node *m* (a bus or a substation) is proportional to the maximum allowable global contribution $G_m(h)$ at node *m*. In other words, the harmonic voltage allocation for load S_i connected to bus *m* is:

(iv) $$E_{U\,i}(h) = G_m(h)\sqrt[\alpha]{\frac{S_i}{S_{tm}}} \quad (3.15)$$

The equivalent harmonic current allocation to that distorting load can be defined using:

(v) $$E_{I\,i}(h) = \frac{E_{U\,i}(h)}{Z_{i,i}(h)} \quad (3.16)$$

S_i: Agreed Power of the load S_i;

S_{tm}: Total supply capacity at node *m*;

$E_{U\,i}\,(h)$: Emission limit of load S_i connected at bus m;

$G_m(h)$: Maximum global contribution to the h^{th} harmonic voltage of all distorting loads that can be connected at bus m;

$Z_{i,\,i}\,(h)$: Harmonic impedance of the system at bus i for installation (S_i) – using scalar quantities only ($|Z_{i,\,i}\,(h)|$).

Harmonic performance can be evaluated based on the total harmonic voltage calculated at each bus, e.g. bus i, according to (3.17) below:

$$V_i(h) = \sqrt[\alpha]{\sum_{j=1}^{n}\left(\left|Z_{(i,j)}(h)\right| \times E_{I\,j}(h)\right)^{\alpha}} \tag{3.17}$$

Two key tasks under the IEC report [10] Section 9.2 - Stage 2: "emission limits relative to actual system characteristics" - include:

- Section 9.2.1 of [10]: Assessment of total available power of a substation;
- Section 9.2.2 of [10]: Method for sharing planning levels between busbars at HV and EHV.

The application of the IEC's allocation methodology for loads in the 7-bus transmission network case study has highlighted a number of practical issues that will be examined in detail in the sections below.

3.5 Analysis of the IEC Method for Resonant Conditions

The influence of harmonic resonances on the global harmonic emissions in transmission system is significant and must be analysed. The sources of these harmonic resonances may originate from remote amplifications due to capacitor banks, transmission line capacitance and even interaction between harmonic loads in meshed transmission systems. The IEC method recognised that in meshed HV/EHV systems the distortion caused by the installations at node i may have more impact on the voltage distortion at node j, than at node i. There are cases for which the *influence coefficients* ($K_{j\text{-}i}\,(h)$) can be quite high where series resonance exists between nodes i and j. Treatment for series resonance, but not parallel resonance, is also included in the IEC report [10] as described below to lower harmonic emission limits at node i, rather than unduly limiting emissions at node j.

It was suggested in Appendix D.2.2 of [10] that wherever the *influence coefficient* ($K_{j\text{-}i}(h)$) is greater than unity, a reduction factor of $F_{z\,j}$ must also be applied to that influence coefficient to reduce the impact of resonances to an acceptable level. The corrected influence coefficient is defined by:

$$K^{\alpha}_{n-m\_Corrected}(h) = \left(K_{n-m}(h) \times F_{Z\,j}\right)^{\alpha} \tag{3.18}$$

$$F_{z\,j} = \frac{Z_j(h)}{h \times Z_{1\,j}} \tag{3.19}$$

The harmonic current emission limit at busbar j is calculated by:

$$E_{I\,j}(h) = \frac{E_{U\,j}(h)}{h \times Z_{1\,j}} \tag{3.20}$$

where:

$Z_j(h)$: harmonic impedance at node *j* at harmonic order *h*;

Z_{1j}: harmonic impedance at node *j* at fundamental frequency;

$K_{n\text{-}m\_Corrected}$: c*orrected Influence Coefficient* between nodes *n* and *m.*

Derivation of this correction factor F_{zj} is based on the assumption that the system is purely inductive, i.e. all resistive and capacitive elements are ignored. Resonance condition exists between node *j* and *i* when $Z_{h(i,j)} > Z_{h(i,i)}$ (i.e. $K_{hj\text{-}i} > 1$), because 1 p.u. a voltage applied at node *j* will produce more than 1 p.u. the voltage at node *i*. However, under the assumption of a purely inductive system, harmonic impedances would increase linearly with harmonic order *h*, i.e. $Z_h = h \times Z_1$ - Where Z_1 is the impedance at the fundamental frequency. Both phase angles of harmonic impedances and influence coefficients would be constant over the entire spectrum of harmonic frequencies. In this thesis, summation law has been applied, only absolute *influence coefficients* are considered.

In contrast, results obtained from case studies undertaken in this research project have shown that the influence coefficients calculated for any realistic network would vary nonlinearly with harmonic frequencies, i.e. $Z_h = F(h) \times Z_1$ - Where $F(h)$ is a complex non-linear function and heavily dependent on network models and network configurations. Harmonic studies for transmission systems using a purely inductive network model would omit critical resonance conditions that may otherwise have significant effects on harmonic allocations and harmonic voltage performance in the network. Therefore, the application of the influence coefficient correction factors in [10] may be useful for distribution networks with a small number of capacitive elements. However, it is not recommended for a realistic transmission network with long lines and large capacitor banks, which are the major sources of resonances [57]. Long transmission lines and large capacitor banks often lead to a greater likelihood of harmonic resonances at the remote buses. In addition, for transmission systems, variation in network configuration can influence the resonance frequencies, phase angles and amplitudes of resonant impedances that have direct effects on harmonic allocations and harmonic voltage performance.

3.6 Supply Capacity at a Bus

This research project examines harmonic allocations for loads of the 7-bus network based on different generation dispatch under various network scenarios and investigates if the supply capacity at a bus may be adjusted, or shifted from one bus to another by changing the generation dispatch and reconfiguration of network elements. For example, the supply capacity at Bus 1 in the case study above is S_{t1} = 510.77 MVA. Through load flow studies, this figure was planned and defined as the *maximum supply capacity* that can be achieved at that bus based on the selected network configuration. In practice, the supply capacity at a bus may be varied depending on the chosen network configuration subject to the following factors as illustrated in Figure 3.9 below:

i) The thermal limit of network elements, e.g. transmission line, transformer;

ii) Steady-State-Stability limit;

iii) Transient-Stability limits (e.g. frequency and voltage transients);

iv) Electrical damping limit (e.g. frequency oscillations).

For networks that are part of a National Electricity Market (NEM), e.g. Australian NEM, another important factor that can also constraint the practical limits of the supply capacity at some particular buses is the contractual agreement between loads, generators and network owners. These are commercial limits rather than technical limits so they are not in the scope of this thesis.

Generally, the assessment of the supply capacity (S_t), as described in [10], must satisfy all relevant contingency conditions and applicable limits, which for a transmission system may include: (n-1), (n-1-1), (n-2), and (n-1-5 50 MW) redundancy; thermal limit; steady-state-stability limit; transient stability limit; and electrical damping limit, as part of the network planning process.

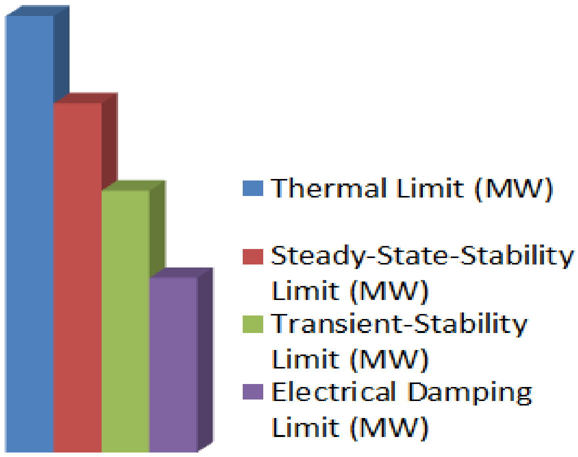


Figure 3.9 – Different Supply Capacity Limits at a Bus

Due to the significant differences in the order of magnitude of the various contingency rating, selection of the appropriate conditions for harmonic allocations may have a significant bearing on final emission allocations.

3.7 Deficiencies of IEC's Harmonic Allocation Methodology

Harmonic allocation case studies undertaken in this project identify a number of deficiencies associated with the IEC allocation methodology. These deficiencies will be analysed in practical case studies and below.

3.7.1 Dependency on Load Forecast and Future Network Augmentation

Under Section 9.2.1 of the IEC technical report [10], S_t is defined as an approximation of the total power of all installations at a busbar or a substation based on load forecast and load flow studies. The total power (S_t) of all installations for which emission limits are to be allocated in the foreseeable future is dependent on load forecasts and future network scenarios, takes into account future network reconfiguration and augmentation, as given by Equation 10 in [10], repeated here as (3.21) and depicted in Figure 3.10.

$$S_t = \sum S_{Din} + \sum S_{out} + \sum Q_{Dshunt} \tag{3.21}$$

where:

S_t (in MVA): An approximation of the total power of all installations for which emission limits are to be allocated in the foreseeable future;

S_{out} (in MVA): Power flowing out of the considered HV-EHV busbar, including provision for future load growth;

S_{Din} (in MVA): The power of any HVDC stations or non-linear generating plants;

Q_{Dshunt} (in MVAr): The dynamic rating of any thyristor-controlled reactor (TCR) of any Static VAr compensators connected at the busbar under consideration.

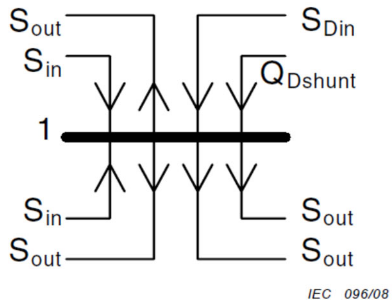


Figure* 3.10 *– Determination of S_t for a Simple HV or EHV System [10]

Equation (3.21) only refers to the total power (S_t) of all installations, including future loads, and omits the *total supply capacity* (S_{tm}) at the connection point, e.g. a busbar/substation. In practice, it would be very difficult to predict *total future loads* (S_t) accurately at all busbars or to calculate *total supply capacity* (S_{tm}) for a large number of network scenarios, a few thousands for a large transmission network, that depend on unknown future network scenarios. In addition, it was found that power flows in and out of a busbar, as illustrated in Figure 3.10, and network harmonic impedances in a meshed transmission system can change significantly from one network configuration to another. Such uncertainties can lead to too high allocation (over-allocation) or too low allocation (under-allocation) throughout the transmission network. Ignoring the effects of changing network impedances on harmonic allocations, the main reason for under-allocation or over-allocation is due to the mismatch between the estimated total future loads and the supply capacity, taking into account harmonic power absorption capabilities and impedance attenuation characteristics at different busbars in the network. These issues make harmonic allocation in transmission system even more challenging.

The effect of selecting a particular *(St)* has a significant impact on subsequent allocations. However, the report in [10] does not explicitly clarify the relationship between the total *supply capacity* (S_{tm}) and total load (S_t) at busbar *m*. The process in the IEC standard, in its current form, suggests that the total anticipated load (S_t) at a bus is the same as the *supply capacity* of that bus (S_{tm}). This assumption seems logical in theory, but not in practice because the *supply capacity* must always be greater than the *total loads* for the power system to function.

Equation (3.21) and Figure 3.10 are not aligned with each other, for example, power flows into the bus (S_{in}) is shown in Figure 3.10, but not in equation (3.21). The inter-dependent relationship between the total connecting load, the *total supply capacity* and harmonic absorption and impedance attenuation capability in transmission systems is very important in harmonic management. A good understanding of this relationship would provide key insight information to achieve better harmonic management for transmission systems. The concept of network harmonic absorption and impedance attenuation capability is equally important as the supply capacity and load, but it is not referenced anywhere in the IEC report.

The dependency of [10] on future network scenarios is demonstrated in the case study below, which also purposely assumed that the *total load* can be the same as the *total supply capacity* at a PCC. It means that the optimal allocation can only be achieved when the *total supply capacity* is the same as the *total load* (including future loads) as per the intention of [10].

3.7.2 Case Study 1 – Load 12 Not Included in Future Network Scenario

Assuming that Load 11 is proposed for connection to Bus 1. At that time, Load 12 was not foreseen for any future network development scenarios. The SVC, which harmonic allocation was previously allocated based on the IEC method, already exists and connected Bus 1. The size of the SVC Thyristor Control Reactor (TCR1) is S_{TCR} = 115 MVAr. According to equation (3.21) the total load, including future network scenarios, at Bus 1 is $S_{t(Total\_Loads\_at\_bus\_1)} = S_{Load\_11} + S_{TCR1} = 244.73 + 115 = 359.73\ MVA$. However, the load flow of the case study network indicated that the total supply capacity at Bus 1 can be up to S_{t1} = 510.77 MVA. In this case, the application of the IEC report methodology [11] results in a large difference between the *total anticipated load* and *total supply capacity*. Based on equations (3.11) – (3.14), the maximum allowable global harmonic emission at bus 1 will be unnecessarily constrained by up to 30%. Voltage and current harmonic allocations for Load 11 will also be restricted accordingly. Allocation received for Load 11 in this case study is considered as under-allocation because the maximum global contribution from Bus 1, where both Loads 11 and 12 are connected, is unnecessarily restricted.

This case study has demonstrated that the IEC report method heavily depends on load forecast and prediction of future network scenarios, including network reconfiguration and network development. In practice, both of these factors are influenced by economic activities and financial market sentiments, which can be highly unpredictable and volatile at times. Procedures in [10] do not address the uncertainty and inaccuracy of load forecast that could significantly influence the harmonic allocation and harmonic performance. Perhaps, harmonic allocation methodology should be less dependent on load forecast and future network scenarios.

3.7.3 Case Study 2 – Load 12 included Future Network Scenario

Load 11 is proposed to be connected to Bus 1 now and Load 12 is estimated for future connection. The SVC, connected to Bus 1, was previously installed and its harmonic voltages were allocated based on the

IEC method. The MVA size of the SVC Thyristor Control Reactor (TCR) is S_{TCR} = 115 MVAr. Harmonic allocation to Load 11 (Bus 1), Load 2 (Bus 2) and Load 5 (Bus 5) are assumed to be at an optimal level already, i.e. total load matches total supply capacity at the connection point, and Load 6 (Bus 6) is currently excluded from this case study. In this scenario the exact size of Load 12 (future load) is not yet known, hence harmonic allocation for Load 12 can be just right (i.e. optimal), too low (under-allocation) or too high (over-allocation) depending on the accuracy of load forecast. The total load at Bus 1 could result in one of the three scenarios below. The results show that harmonic allocation for Load 12 varies according to load forecast, as shown in Table 3.6 and graphically illustrated in Figure 3.11 below.

A. Under Allocation:

(i) Future load: Load_12 < 151 MVA;

(ii) Total load at Bus 1:

(iii) $S_{t(Total\_Loads\_at\_bus\_1)} = S_{TCR1} + S_{Load\_11} + S_{Load\_12} < 510.77\ MVA$; (3.22)

(iv) SVC Impedance: Excluded from the network model;

(v) Global harmonic contribution at bus 1: Restricted below the Optimum level;

(vi) Harmonic allocation to loads connected to bus 1: Under-allocation;

(vii) Network harmonic voltages: Below planning levels.

B. Optimal Allocation (best scenario):

(i) Future load: Load_12 = 151 MA;

(ii) Total load at Bus 1:

(iii) $\mathrm{S_{t(Total\_Loads\_at\_bus\_1)} = S_{TCR1} + S_{Load\_11} + S_{Load\_12} = 115 + 244.73 + 151 = 510.77\ MVA}$; (3.23)

(iv) SVC impedance: Excluded from the network model;

(v) Global harmonic contribution at bus 1: Optimal;

(vi) Harmonic allocation to loads connected to bus 1: Optimal;

(vii) Network harmonic voltages: At or below planning levels.

C. Over Allocation:

(i) Future load: Load_12 > 151 MVA;

(ii) Total load at Bus 1:

(iii) $S_{t(Total\_Loads\_at\_bus\_1)} = S_{TCR1} + S_{Load\_11} + S_{Load\_12} > 510.77\ MVA;$ (3.24)

(iv) SVC Impedance: Excluded from the network model;

(v) Global harmonic contribution at bus 1: Above the Optimum level;

(vi) Harmonic allocation to loads connected to bus 1: Over-allocation;

(vii) Network harmonic voltages: Exceed planning levels.

D. Over Allocation with SVC Impedance: Load_12 > 151 MVA

(i) Future Load: Load_12 > 151 MVA;

(ii) Total Load at bus 1:

(iii) $S_{t(Total\_Loads\_at\_bus\_1)} = S_{TCR1} + S_{Load\_11} + S_{Load\_12} > 510.77\ MVA$; (3.25)

(iv) SVC Impedance: Included in the network model;

(v) Global harmonic contribution at bus 1: Above the Optimum level;

(vi) Harmonic allocation to loads connected to bus 1: Over-allocation (similar to the result in (c) above);

(vii) Network harmonic voltages: Exceed planning levels (much worse than results in (c) above).

3.7.4 Case Study Allocation Results

One of the key guiding principles of the IEC report is that when all distorting installations are injecting levels of harmonic distortion equal to their emission limits, the total disturbance level anywhere in the system should not exceed the planning level and must satisfy:

$$\left(K_{h1-m}^{\alpha}\left(\textstyle\sum_{i\ at\ B1} E_{Uhi}^{\alpha}\right) + K_{h2-m}^{\alpha}\left(\textstyle\sum_{i\ at\ B2} E_{Uhi}^{\alpha}\right) + \cdots + K_{hn-m}^{\alpha}\left(\textstyle\sum_{i\ at\ Bn} E_{Uhi}^{\alpha}\right)\right)^{\frac{1}{\alpha}} \leq L_{hHV-EHV} \tag{3.26}$$

$$Where\ \textstyle\sum_{i\ at\ Bj} E_{Uhi}^{\alpha} \leq G_{hBj}^{\alpha} \tag{3.27}$$

This needs to be satisfied for all buses, across all harmonics, with the selection of relevant summation exponents (α) for different harmonic orders. The same condition for all busbars needs to be evaluated to find the minimum global contribution (G_{hBm}) that will ensure harmonic voltage levels at bus m are not exceeded.

In real operational systems, the total supply capacity must always be greater than the total loads at any busbars. The difference between the *total supply* and the *total load* at a bus would be considered as *spare* *supply capacity* at that bus. Therefore, the global contribution at bus *m*, (G_{hBm}), which relies on the total supply capacity, would also depend on the spare supply capacity.

In both over-allocation scenarios C. and D. above – without and with SVC impedance, harmonic voltage allocations to Load 12 are essentially the same, with only negligible variations at some frequencies due to changes of network harmonic impedances influenced by the SVC impedance. However, harmonic voltage performance, illustrated in Figure 3.12 – 3.15, showed larger differences of bus's harmonic voltages between the two cases. The exclusion or inclusion of SVC impedance in the network model has insignificant effects on harmonic allocation to Load 12, but much more impact on harmonic voltage performance due to changes of network harmonic impedances coupled with injection from other harmonic sources, e.g. Loads 11, 2 and 5.

The case studies conducted have found that the application of the IEC report method has the potential to under-allocate more often than over-allocate. One possibility is that users attempt to match future loads, which are highly uncertain and may not eventuate at all, with the existing supply capacity at the PCC. Furthermore, network planners often focus more on load flow studies to ensure that the network has adequate voltage and frequency stability margins. Generally, the more supply headroom at power frequencies, i.e. differences between supply capacity and loads, means the better stability margins. In harmonic terms, the extra supply headroom could also mean the network has more harmonic absorption capability. Another possible explanation for under-allocation occurs more often is because the harmonic absorption capability of the network is not effectively utilised. Therefore, the global harmonic contribution at a bus is unnecessarily constrained and lead to under-allocation to all loads connected to that bus.

Harmonic allocation to Loads 11, 12, 2 and 5 based on the IEC report method in its current form comply with planning levels but may result in under-allocation if not all information is available, e.g. Load 12 as shown in Figures 3.11, 3.12 and 3.13 below. Figure 3.11 shows a variation of harmonic allocation to Load 12, which include four cases - under, optimal, over allocations without and with SVC impedance. According to the IEC/TR method, optimal allocation, i.e. harmonic voltages reach planning levels, only occurs when total load matched total supply capacity at a PCC. There is a significant difference in voltage under an optimal allocation case. In the case study, SVC impedance would cause a reduction of voltage allocation at some frequencies due to resonance conditions.

Figure 3.11 show harmonic allocation to Load 12 under four (4) allocation scenarios. There are significant differences in harmonic allocation between scenarios. Under allocation and optimal allocation result in busbar harmonic voltages at or below planning levels as shown in Figure 3.12 and Figure 3.13. Figure 3.12 shows busbar voltages are well under planning limits due to under allocation, hence only planning level graphs are shown, which over-shadow busbar voltages. Figure 3.13 also shows the results of optimal allocation that also lead planning level graphs overshadow busbar voltages, which are equal to or below planning levels.

Over-allocation can occur if the estimation of total future loads exceeds supply capacity/absorption capabilities and impedance attenuation limits at PCCs as shown in Figures 3.14 and 3.15. These graphs show harmonic voltages exceed planning levels at some harmonics as anticipated. It was observed that harmonic voltage amplification, impedance attenuation and harmonic power absorption capabilities at PCCs in the network play a vital role in the allocation process. They ought to be included in the planning process to determine the harmonic supply capacity for loads at the PCCs. These considerations are not currently discussed in the existing IEC report method.

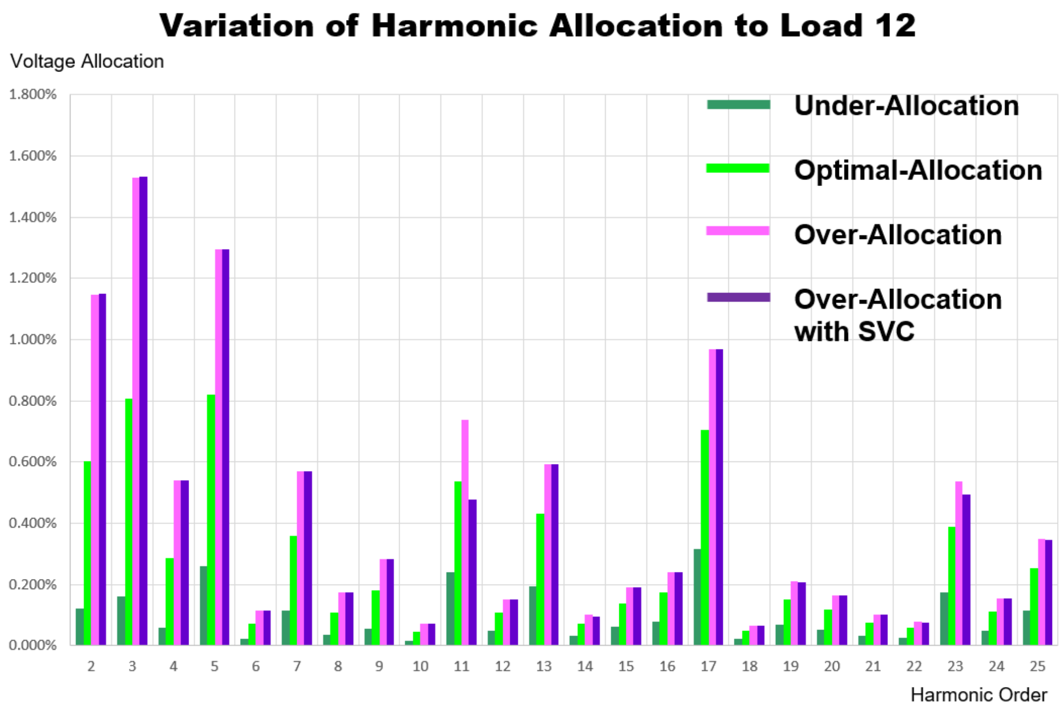


Figure 3.11 – Variation of Harmonic Allocation to Load 12

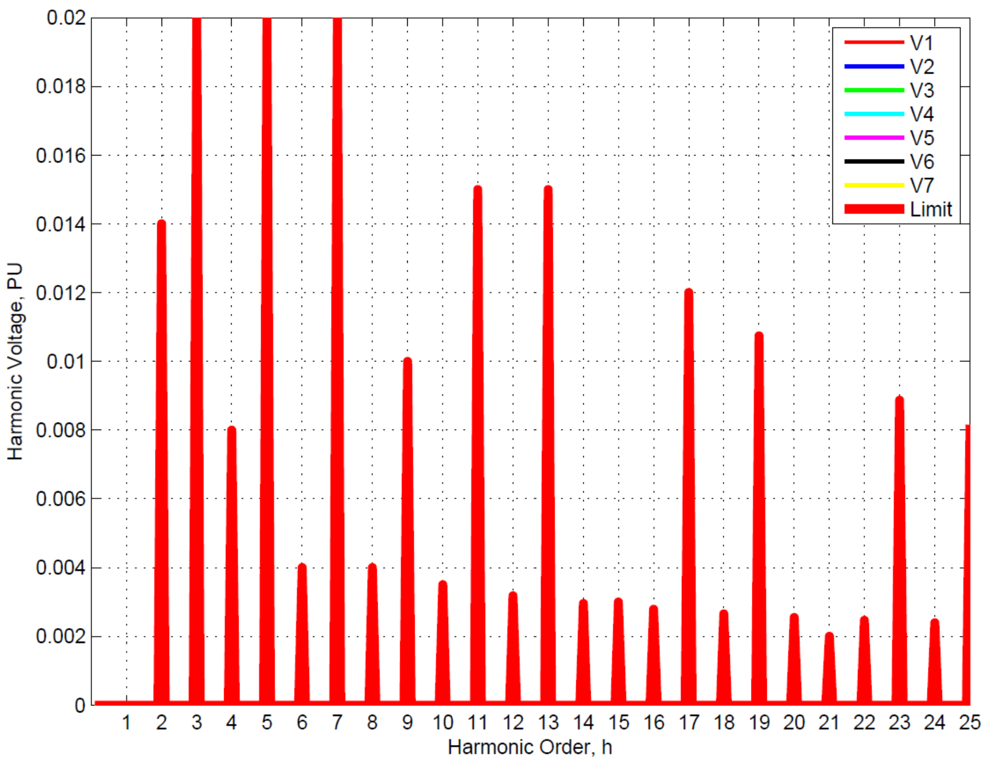


Figure 3.12 – Harmonic Voltage Performance - Under-Allocation to Load 12 without SVC impedance

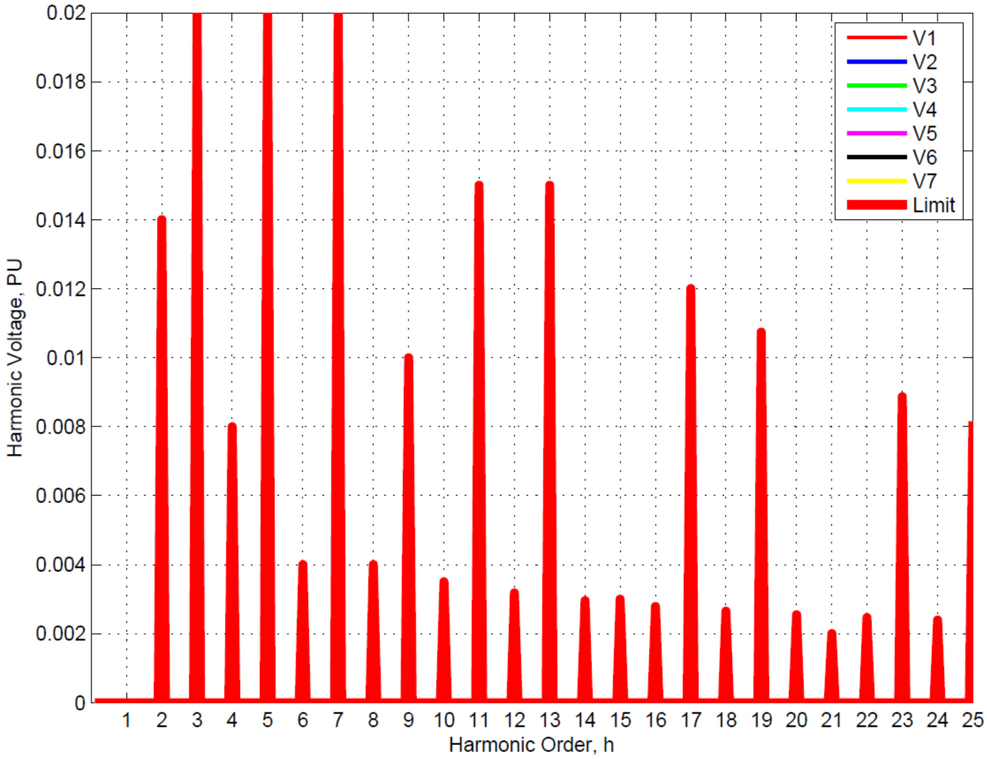


Figure 3.13 – Harmonic Voltage Performance - Optimal Allocation to all Loads without SVC impedance

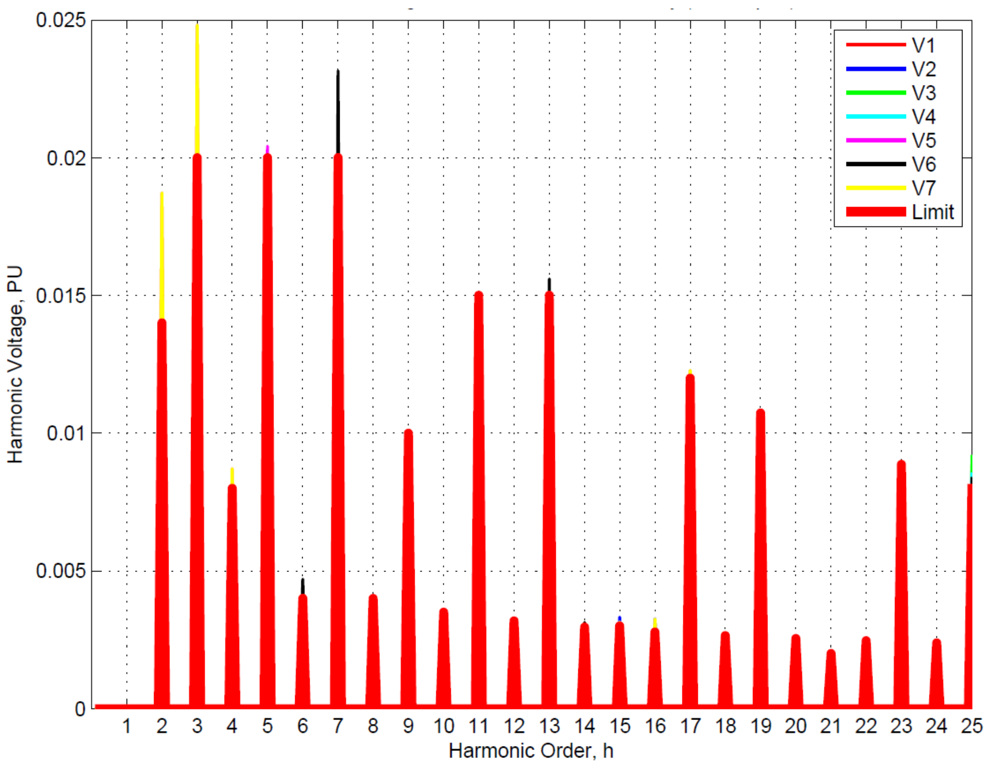


Figure 3.14 – Harmonic Voltage Performance - Over Allocation to Load 12 without SVC impedance

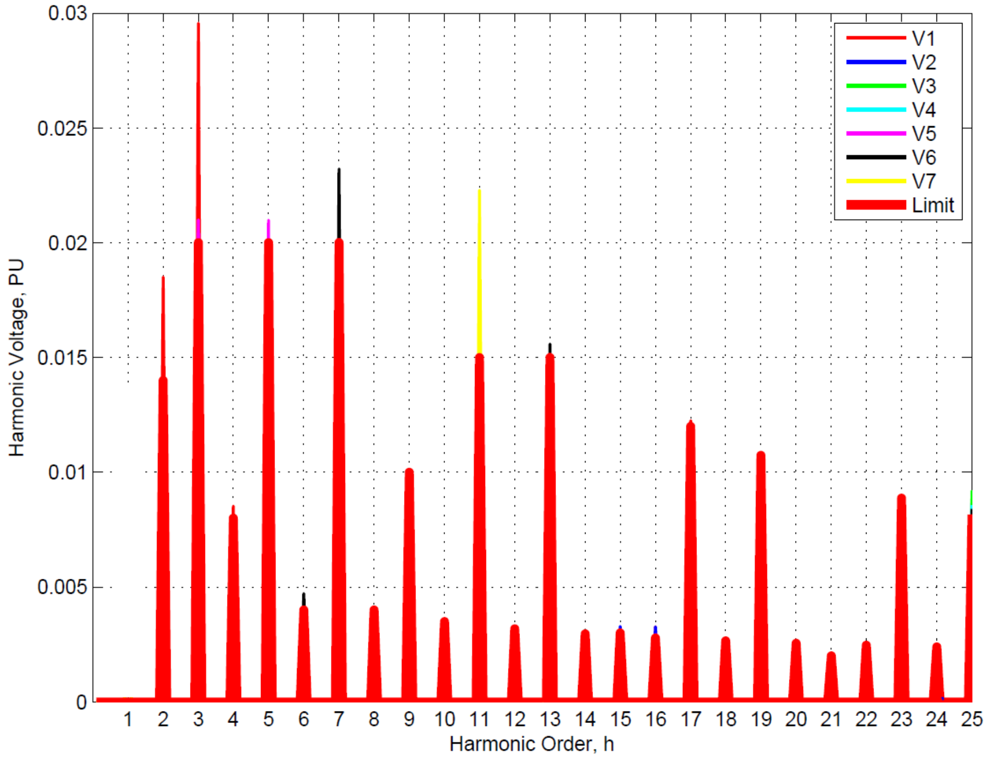


Figure 3.15 – Harmonic Voltage Performance - Over Allocation to Load 12 with SVC impedance

Changes of voltage allocations to Load 12 are presented on the left columns of Table 3.6. In this case study, with the application of the IEC report method, under-allocation and optimal allocation only occur when SVC impedances are not included. If the optimal allocation is applied to Load 12 and inclusion of SVC impedance, extra capacitive elements of the SVC, e.g. Thyristor Switch Capacitors (TSC) and harmonic filters would cause resonances and push busbar voltages slightly over-planning limits. In this scenario, if SVC impedance is included in the model, optimal voltage allocations of Load 12 would have to be reduced by a small margin to comply with planning levels. To simplify the allocation approach, harmonic allocations to Loads 11, 2 and 5 were deliberately set at optimal levels, i.e. loads match supply capacities at relevant PCCs.

Table 3.6 – Harmonic Allocations to Loads 11, 12, 2 and 5 – Variation of Harmonic Allocation to Load 12

Harmonic Allocations to Loads 11, 12, 2 and 5 (harmonic voltage in percent) **Variation of Allocation to Load 12 Due to Load Forecast**							
	Load_12				Load_11	Load_2	Load 5
h	A Under Allocation	B Optimal Allocation	C Over Allocation	D Over Allocation	Optimal Allocation		
	Without SVC Impedance			With SVC Impedance	Without SVC Impedance		
	Fig. 3.12	Fig. 3.13	Fig. 3.14	Fig. 3.15			
2	0.121	0.603	1.146	1.151	0.603	0.225	0.563
3	0.161	0.805	1.530	1.534	0.805	0.301	0.752
4	0.057	0.284	0.540	0.541	0.284	0.106	0.265
5	0.259	0.819	1.295	1.296	0.819	0.405	0.779
6	0.023	0.072	0.114	0.114	0.072	0.036	0.069
7	0.114	0.360	0.569	0.569	0.360	0.178	0.343
8	0.035	0.109	0.173	0.173	0.109	0.054	0.104
9	0.057	0.179	0.283	0.282	0.179	0.089	0.170
10	0.015	0.046	0.073	0.072	0.046	0.023	0.044
11	0.239	0.535	0.738	0.476	0.535	0.327	0.517
12	0.049	0.109	0.150	0.150	0.109	0.066	0.105
13	0.192	0.430	0.593	0.594	0.430	0.263	0.416
14	0.033	0.073	0.101	0.094	0.073	0.045	0.071
15	0.062	0.138	0.190	0.190	0.138	0.084	0.133
16	0.078	0.175	0.241	0.241	0.175	0.107	0.169
17	0.315	0.704	0.970	0.970	0.704	0.430	0.680
18	0.022	0.048	0.067	0.066	0.048	0.030	0.047
19	0.068	0.151	0.209	0.208	0.151	0.093	0.146
20	0.053	0.119	0.164	0.164	0.119	0.073	0.115
21	0.033	0.075	0.103	0.103	0.075	0.046	0.072
22	0.025	0.057	0.079	0.076	0.057	0.035	0.055
23	0.174	0.388	0.535	0.495	0.388	0.237	0.375
24	0.050	0.112	0.154	0.154	0.112	0.068	0.108
25	0.113	0.253	0.349	0.347	0.253	0.155	0.245

3.8 Under-Utilisation of Network Absorption Capability

The main focus of this section is to analyse challenges associated with the under-utilisation of network absorption capability, which is considered as one of the deficiencies of the IEC report, to understand the issues and find satisfactory solutions. The supply capacity at a bus depends on the network configuration and network elements, such as transmission lines, transformers, generators, loads and reactive plants, etc., all have the ability to absorb harmonics [1]. Based on this explanation, it is logical to derive that there might be an interdependent relationship between network supply capacity and harmonic absorption capability. Especially, in a conventional power system, the main source of supply is from synchronous generators that can provide a low impedance path for harmonic currents. Generally, the supply capacity at the PCC of interest in the network is assessed during the planning phase that often involves simulation studies of many network scenarios. In practice, it is not uncommon to see supply capacities at some transmission busbars are up to 50% higher than the total loads. Therefore, the IEC report's allocation method, which depends on the total anticipated loads, has not effectively utilised the network absorption capability associated with the spare supply capacity of the operational network.

Based on discussions above, the relationship between the *supply capacity*, the *total load* and *spare supply capacity* at a busbar can be expressed in equation (3.28) below:

$$S_{t\_Supply\_Capacity\_Bus\_i} = \sum_{a=1}^{n} S_{Loads\_a} + S_{Spare\_Supply\_Capacity\_Bus\_i} \tag{3.28}$$

It was observed during the planning process, network supply capacities can vary significantly depending on network scenarios and generation dispatch. In the absence of a comprehensive harmonic management framework, network planners tend to be even more conservative by reserving extra supply capacities at major substations, i.e. larger supply headroom at busbars, to minimise chances of network instability and load shedding during and after a networking event. This practice further exacerbates the issues of underutilisation of network harmonic absorption capability. By design, allocations based on the IEC report method to date are likely to be under-allocated; hence, there should still be significant spare supply capacity / harmonic absorption capability remain in the existing networks. This situation seems to be favourable for transmission network operators, i.e. large harmonic absorption capacity remain in the network. However, it may also mean that there have been additional costs incurred to existing load owners to lower their harmonic emissions unnecessarily. To improve the existing harmonic allocation methodology, two challenges should be addressed. Firstly, the *maximum global harmonic emission* at each bus, which has a direct influence on harmonic allocations to individual loads connected to the same bus, should be calibrated proportionally with the network's planned supply capacity, absorption capability and loads. Secondly, there should be more focus on strategic network planning practices that would allow extra supply capacities to be redirected from one network area to another that has higher prospects of committed load growth. Solutions for these challenges will be discussed in details in Chapter 5 and Chapter 8 respectively.

3.9 Ambiguous Expressions and Processes

The mathematical expression for allocation of individual harmonic limits in the existing IEC methodology requires further clarification to ensure existing, planned, and future connection of loads or equipment are treated fairly. Especially where there exist complexities due to: allocations completed under different methods, a mismatch between expected and existing harmonic levels, mixed diversity of harmonic producing loads/equipment, or where limited network data is available.

The current method for assessing individual limits expressed by Equation 15 in Section 9.2.3 of [10] is repeated in this thesis as equation (3.15) above. This equation does not account for the size and harmonic emission from existing loads that are already connected to the same busbar. Mere application of this expression for loads connected to a busbar that has pre-existing loads can result in over-allocation. The IEC report implies that the *total supply capacity* (S_{tm}) at busbar *m* should also match the *total power* of all installations for which emission limits are to be allocated to the total future loads. However, there is no clarification for differences between the two terminologies, i.e. *total future loads* (S_t) and *total supply capacity* (S_{tm}) at a bus. They must be the same to achieve maximum global harmonic contribution at a busbar. This condition can't occur in any practical power systems due to operational constraints as discussed above. Therefore, the surplus (spare) supply capacities at each busbar in operational systems, which also represent the additional network absorption capabilities, should be utilised to increase harmonic allocation to loads. This requires further investigations, i.e. should the additional (spare) network absorption capacities be taken into account when allocating harmonics to loads? How can spare network absorption capacities be applied to the existing IEC method? What frameworks can be considered to balance the relationship between the supply capacity, harmonic absorption capability and loads? What are potential implications for networks with high penetration of renewable generation sources, such as solar, wind and battery? These questions will be thoroughly examined and relevant solutions will be proposed in Chapters 5 - 8.

3.10 Summary

This chapter focused on identifying existing deficiencies of the IEC report allocation methodology. A number of deficiencies associated with the IEC's allocation methodology have been identified. They include: (i) the method to assess the *total supply capacity* and *total loads* that highly depend on uncertain futuristic scenarios, and the ambiguous application between the two terminologies – *Total Loads versus Total Supply*; (ii) the method for sharing planning levels between HV-EHV buses does not allow *unused spare capacity* to be utilised to increase *the total harmonic contribution* (G_{hBm}) at a bus; and (iii) the method for allocating individual limits to loads does not take into account allocations to existing loads in the system.

The method of investigation was an evidence-based approach that utilised realistic case studies and discussion-based sections. A 7-bus 132kV transmission network was established as a case study network to sufficiently represent the complexities of an operational transmission system in Australia and included an SVC. Network elements, including the SVC, were modelled based on CIGRE's recommendations. Harmonic allocation for loads was undertaken using the IEC report Stage 2 method (as this is the most applicable stage for transmission systems).

Overall, practical application of the IEC harmonic allocation to major loads in a realistic transmission network is difficult because of necessary assumptions and ambiguous procedures. The IEC method appears adequate for simplified network models, but not for realistic transmission systems. A number of deficiencies have been identified:

- The method used to correct influence coefficients under resonance conditions was found impractical for transmission systems because they typically have a higher number of capacitive network elements such as voltage support capacitors and long transmission lines.
- The allocation method heavily relies on load forecast and prediction of future network scenarios that are difficult to accurately predict and can lead to under-allocation or over-allocation.
- The method for sharing planning levels between HV-EHV busbars does not allow the full network absorption capability to be utilised effectively, hence often result in under-allocation;
- The method to assess (S_t) as the *total future loads* versus (S_{tm}) as the *total supply capacity* at Bus m is ambiguous. In particular, there is no clear distinction between the *total loads* and *total supply capacity*.
- The method for allocating individual limits to loads does not explicitly take into account the harmonic emission of existing loads.

A new harmonic allocation method is required to overcome deficiencies of the IEC report. A strategic harmonic management framework will also be required to support the application of the new solution under a wide range of network scenarios, including those with high penetration of renewable generation sources. Chapters 5 to 8 will address these challenges.

4 Transmission Network Scenarios and Harmonic Impedances

4.1 Introduction

Harmonic impedances in transmission systems can change significantly concerning both magnitude and phase angle under different network scenarios. These changes are heavily dependent on the mix of network elements, e.g. transmission lines, synchronous machines (generators), capacitors, transformers and loads. Consequently, harmonic allocation methodologies dependent on network impedances, such as the IEC Stage 2 evaluation, will be sensitive to network scenarios. Although not explicitly stated, the IEC approach assumes that network planners determine the worst-case impedance, for each harmonic, from potentially thousands of scenarios (within operational constraints). Planners thus require a comprehensive understanding of network scenarios and how they affect harmonic impedances, allocations, and harmonic voltage performance. The IEC method and relevant literature are yet to address how to efficiently determine the "worst-case" scenario, which yields the lowest allocation, for transmission systems. It is not a straightforward task, requiring both significant effort and sound analysis tools, especially with large numbers of network scenarios.

A typical operational transmission system can have 500 buses or more and up to a few thousand network scenarios. Without a methodical approach to help to select one or more suitable network scenarios for harmonic allocations in transmission systems, the application of the IEC's method can become impractical. It is thus important to derive a methodology to minimise the number of network scenarios required for harmonic allocation, but still, maintain the acceptable level of accuracy and certainty. A new approach is required to choose one set of allocations, out of thousands, that best suits specific requirements. This chapter will examine three key aspects: (i) contributing factors to harmonic impedance; (ii) variations of harmonic impedance under different network scenarios; and (iii) impacts of network scenarios on resonances and allocations. Findings will contribute to the development of the strategic planning framework for harmonic management in transmission systems in Chapter 8.

4.2 Contributing Factors to Transmission Systems Impedance

The methodology undertaken to identify major factors that contribute to variations of harmonic impedances in transmission systems is based on a systems engineering approach of decomposition and reconstruction [62, 63]. The approach is well-known in other industries for design, manufacturing, maintenance and incident investigation of complex systems and involves breaking down such systems to their lowest level, i.e. equipment, elements and subsystems, and reconstructing using a systems integration method. Through this process, a detailed model of network elements, characteristics of equipment, subsystems and final systems are examined to provide in-depth knowledge of components and the integrated system.

The complexity of transmission systems impedance is not new to the electricity supply industry. However, details of its complexity are rarely quantified systematically. In this case, the 7-bus 132 kV case study network in Chapter 3, was updated with Cap 5 and Cap 6 being tuned as 5th harmonic filters instead of non-detuned capacitor banks, shown below as Figure 4.1, was broken down into key network elements. Cap 5 and Cap 6 tuning reactors have been changed from 123.25 mH to 78.88mH to become 5th harmonic filters. Their resistance and capacitance values are the same as shown in Table 3.4. The network was then reconstructed by connecting one type of network element at a time, e.g. transmission lines, generators, capacitor banks, transformers or load, and harmonic impedances at all buses plotted, analysed and compared. Finally, the complete 7-bus transmission network was fully reconstructed back to its original form and network harmonic impedances (7 x 7 matrix) of the system analysed under 22 different contingency scenarios.

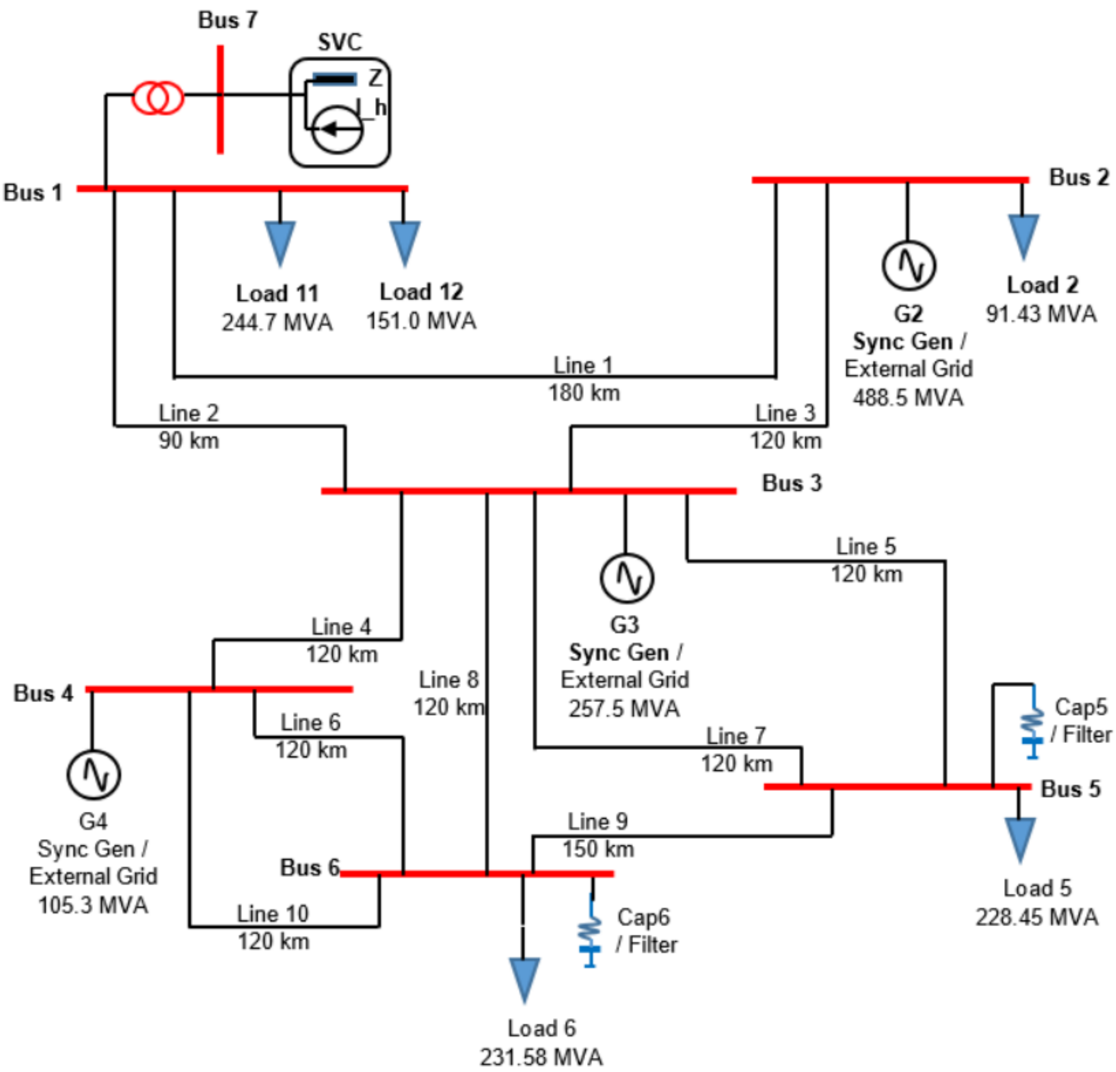


Figure 4.1 – Case Study 7-Bus 132kV Transmission Network

4.2.1 Characteristic Impedance of Transmission Network Elements

Power system simulations rely on the accuracy of network models. Network components for this work were modelled based on the CIRED/CIGRE Guide for Assessing the Network Harmonic Impedance [22]. The primary objective of this section was to examine the contribution of individual network elements and subsystems to the complexity of the impedance of the full transmission network in Figure 4.1.

4.2.1.1 Synchronous Generator

Synchronous generators were modelled as per Section 3.3, which is principally related to their sub-transient reactance (X_d''). X_d'' increases linearly with frequency, and contributes to a reduction of self-impedance at its connection point and nearby busbars. Refer to Appendix B, Section B.1 for more details.

4.2.1.2 Transformer

Transformer characteristic impedance is inductive and its amplitude increases linearly with frequency. Its impedance is modelled in Appendix B Section B.2 and shown in Figure B.5 (a) and (b), which is similar to impedance diagrams of the synchronous generator shown in Figure B.2 (a) and (b).

4.2.1.3 Transmission Line

Characteristics of series impedances and shunt admittances, of Line 1 and 2 in Figure 4.1 are described in Appendix B.3 and illustrated in Figure B.7 (a), (b) and (c). Ignoring voltages and loading conditions of these lines, at harmonic frequencies, the transmission line impedance appears with multiple series and parallel resonances, repeated at certain frequencies, which depend on its length and shunt capacitance. As impedance transitions between resonance points, angle changes from inductive to the capacitive range, and vice versa, e.g. -90^0 to $+90^0$, and the rate of change depends on the on-resistance of the line. Overall, the transmission line appears as inductive and capacitive impedances at different frequencies depending on its length and associated L and C components, which are directly related to the conductor materials and geometry of its structures. Transmission line impedance is closely related to mutual impedance (off-diagonal elements $Z_{i,j}(h)$) and self-impedances (diagonal elements $Z_{i,i}(h)$) of the network impedance matrix $Z(h)$. Parallel and series resonance circuits are formed between the line shunt capacitance and its series inductance at periodic frequencies.

4.2.1.4 Aggregated Loads

Load models have been discussed in Chapter 3 and detailed in Appendix B.4. Load 11, 244.7 MVA at 0.95 power factor, was modelled based on three options, "CIGRE", "R || L", and "Motor" load, as recommended in [22]. Linear loads are generally inductive, however, one model may appear more inductive than others. Depending on the model used, its impedance magnitude and angle vary differently at harmonic frequencies. The impedance of the CIGRE and motor loads increases sharply with frequency, the former has a higher rate of increase than the latter. Above fundamental frequency, the impedance angle of CIGRE load gradually becomes more inductive. The CIGRE model becomes more inductive at high frequency including a large inductive impedance magnitude. Refer to Figure B.11 (b) in Appendix B, the CIGRE load model is more resistive at low frequency, e.g. below 5th harmonic, and becomes more inductive at high frequency, e.g. 60th harmonic. In contrast, the impedance magnitude of the motor load model increases linearly with frequency, more inductive at low frequency and becomes more resistive at high frequency. The impedance magnitude of the R|| L load model is very similar to the motor load model. It becomes resistive very quickly with increased frequency. It is almost purely resistive above the 10th harmonic.

A composite load, which was made up of one-third of each model type, was also included in Figure B.11 for comparison purpose. Its characteristic is similar to the motor load but more resistive above the fundamental frequency. CIGRE load model was used in all case studies in this thesis. It is expected that Loads 11, 12, 2, 5 and 6 will behave like resistive impedance at low frequency, e.g. below 10th harmonic, and inductive impedance at high frequency – very similar to the characteristics of transformer and synchronous generator.

4.2.1.5 Capacitor Bank

Voltage support capacitor banks and harmonic filters, which are often connected to transmission systems as shunt elements, generally have series reactors (inrush/detuning or tuning reactors). Series capacitors (installed in series with transmission lines) are rarely used due to their high costs and are not in the scope of this project. Models and characteristics of shunt capacitor banks are detailed in Appendix B, Section B.5 and Figures B.12 – B.14. As an individual element, a capacitor bank (with a series reactor) has a series resonance at a particular frequency. Its characteristic impedance is capacitive at frequencies below resonant frequency and inductive at frequencies above. Some utilities detune their capacitor banks, e.g. to 2.8th harmonic, to help reduce 3rd harmonic voltages and above. However, it incurs additional costs as each capacitor bank requires a matching detuned reactor, hence a large number of customised reactors and associated spares are required. Other utilities focus on cost-saving by standardising series reactor sizes and ignore the detuning effects. These are called “non-detuned” capacitor banks that have unknown detuned frequencies such that harmonic voltages at connecting buses could be increased/decreased unexpectedly. Detailed examination of tuned and detuned capacitor banks will be conducted in Section 4.3.4 - Parallel and Series Resonances below.

4.2.2 Harmonic Characteristics of Renewable Generation Sources

Renewable generation sources are considered here as large wind and solar plants, with power electronic voltage source converters (VSC) behind an inductive coupling element, often connect to remote PCCs with low short circuit power in transmission networks. VSC-based grid converters generate Pulse Width Modulation (PWM) carrier and side-band voltage harmonics [6], hence harmonic filters are often required at PCCs or its grid-interface converters. A key contribution of solar and wind generators, as observed from the transmission PCCs, are summarised below based on, and further expanded from, information in Chapter 2:

- Negligible ability to absorb harmonics and impedance attenuation,
- Often connected to remote buses with low short circuit power,
- Very small station loads, typically less than 5% of the plant’s generating MVA capacity,
- Modelled as a harmonic current source in parallel with a small station load,
- Introduce composite resonance between AC system and DC converter,
- Introduce negative resistance that reduces the energy absorption capability from the power system.

4.3 Harmonic Impedance Variation due to Network Scenarios

The 132 kV 7-Bus transmission network case study in Figure 4.1 is used to investigate the complexity of transmission network impedance and its variations under different scenarios.

4.3.1 Network Scenarios

The network in Figure 4.1 is gradually reconstructed from individual network elements examined above. The reconstruction sequence is outlined in Table 4.1, with variations of network impedance between stages and a different mix of network elements determined for each.

Network stages, based on (*N-1*) principles, have been included in the study as listed in Table 4.2 below. Network harmonic impedance of the 7-bus network was examined under 22 network scenarios. Additional network scenarios, not included in Table 4.2, may be derived from different combination of scenarios for future studies if deemed necessary. Only a select number of impedance plots, e.g. Bus 1 self and mutual impedances, are illustrated below. Additional impedance plots are presented in Appendix B, Section B.6.

Table 4.1 – Network Harmonic Impedance Case Study –Network Reconstruction Scenarios

Stages	Network Reconstruction Scenarios				Network Elements in Service
	Lines	**Gen**	**Caps**	**Loads**	
(A)	Yes				Lines 1 to Line 10 only
(B)	Yes	Yes			Lines 1 to Line 10 Generator 2, 3 and 4
(C)	Yes	Yes	Yes		Lines 1 to Line 10 Generator 2, 3 and 4 Cap/Filter 5 and 6
(D)	Yes	Yes	Yes	Yes	Lines 1 to Line 10 Generator 2, 3 and 4 Cap/Filter 5 and 6 Loads 2, 5, 6, 11 and 12

The summation law and alpha constants in the IEC technical report [10] have been adopted for case studies in this thesis to account for the time, magnitude and phase diversity of harmonic loads. Characteristics of power electronic converter based harmonic sources, e.g. STATCOMs, solar plant converters, wind plant converters and HVDCs, can change rapidly due to their control systems responding to network conditions at a different time [26]. Adoption of the summation law and alpha constants helps address these challenges.

Table 4.2 – Network Harmonic Impedance Case Study – (N-1) Network Contingency Scenarios

Case ID. (Scenario)	(N-1) Network Contingency Scenarios	Local Connection Bus
1	System intact (all network elements in service)	
2	SVC Out of Service (OOS)	7
3	Line 1 OOS	1-2
4	Line 2 OOS	1-3
5	Line 3 OOS	2-3
6	Line 4 OOS	3-4
7	Line 5 OOS	3-5
8	Line 6 OOS	4-6
9	Line 7 OOS	3-5
10	Line 8 OOS	3-6
11	Line 9 OOS	5-6
12	Line 10 OOS	4-6
13	Capacitor Bank/Filter 5 OOS	5
14	Capacitor Bank/Filter 6 OOS	6
15	Synchronous Generator 2 OOS	2
16	Synchronous Generator 3 OOS	3
17	Synchronous Generator 4 OOS	4
18	Load 2 OOS	2
19	Load 5 OOS	5
20	Load 6 OOS	6
21	Load 11 OOS	1
22	Load 12 OOS	1

4.3.2 Short Circuit Power

Short Circuit Power (SCP), which is inversely proportional to the self-impedances at a fundamental frequency, of the 132 kV 7-bus network was calculated for all buses as shown in Table 4.3. SCP indicates system impedances at a fundamental frequency and is typically used to define strong and weak points of connection. A fundamental frequency, passive network elements in transmission systems are inductive (except capacitor banks), therefore, self-impedance is generally dominantly inductive.

For simplified harmonic allocation calculations in distribution systems, it is often assumed that harmonic impedances increase linearly with frequency from the inverse of the SCP at fundamental. However, this would be rare for transmission systems due to the characteristics of transmission lines. Transmission line characteristics are specific to transmission systems, hence they need to be comprehensively modelled when performing harmonic allocations to loads. Impacts of not including comprehensive line models can be significant as resonance conditions and remote amplification can be unintentionally omitted. Accordingly, in transmission systems, self-impedances that increases linearly with frequency only occur at buses that are dominated by synchronous generators and transformers.

High SCP buses in transmission systems can be associated with three scenarios: (i) buses that have a high number of transmission lines connected; (ii) buses that have a high number of synchronous generators and transformers connected; or (iii) a combination of a high number of lines, generators and transformers at a PCC (not commonly known in real systems).

Characteristics of transmission network harmonic impedances not only depend on SCP but also the composition of different network elements. Figure 4.2 shows the self-impedance, under three network scenarios, at a 275 kV bus in Central Queensland, Australia, with high SCP due to a large number of transmission lines in the area. The impedance has multiple resonances and resembles the characteristics of transmission line impedance. Figure 4.3 shows the self-impedance, at a 132 kV bus in Southern Queensland with very high SCP due to synchronous generators nearby. The impedance varies almost linearly with frequency and resembles characteristics of synchronous generator impedance. Both busbars in Figure 4.2 and 4.3 have high SCP, but their impedance characteristics are significantly different from each other. Figure 4.4 shows the self-impedance at a 275 kV wind farm connection point in Far North Queensland, with low SCP due to its remote location. This busbar is connected to a weak network area (Far North Queensland) via a long transmission line. The self-impedance, which was studied before the windfarm being connected, is significantly different to other busbars in Figure 4.2 and 4.3 due to the combination of long transmission lines and low SCP. It shows parallel resonant impedances at around 7th and 31st harmonics. If no remedial actions applied, the resonance condition would be worse after the wind farm is connected due to more capacitance contribution from MV cables and any applicable filters.

It is noted that load centres in Southern Queensland are electrically far away from the 275kV bus in Central Queensland shown in Figure 4.2 below. Therefore, attenuation effects of remote loads on harmonic impedances observed at this bus are negligible.

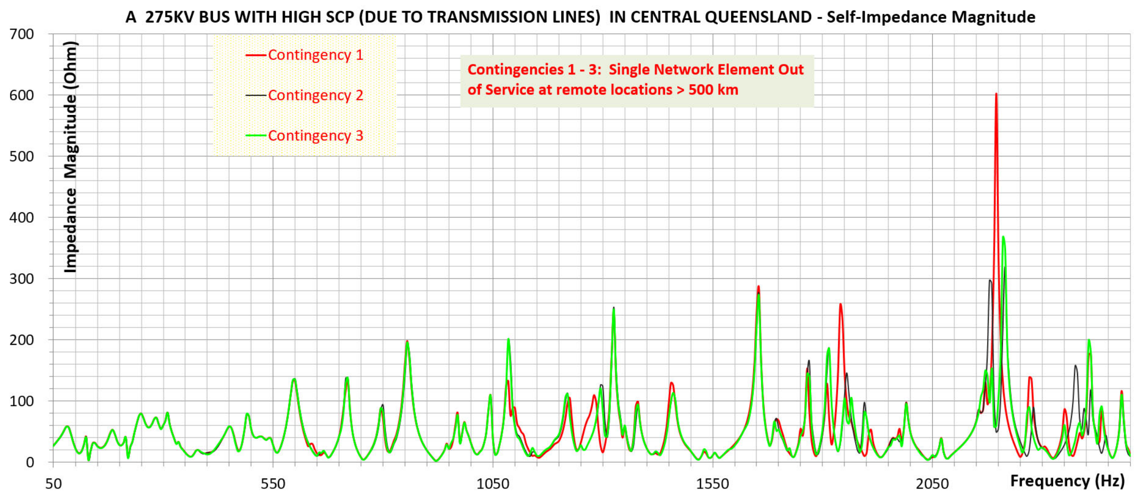


Figure 4.2 –Harmonic Impedances ($Z_{i,i}(h)$) at a 275 kV Bus in Central Queensland, Australia with High Short Circuit Power Due to Transmission Lines

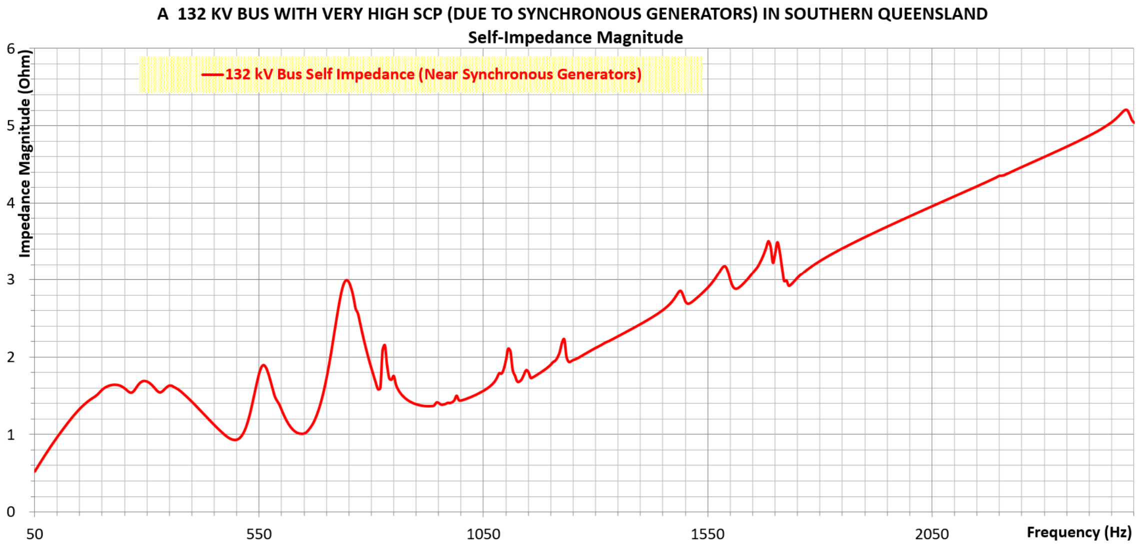


Figure 4.3 –Harmonic Impedance at a 132 kV Bus in Southern Queensland, Australia with Very High Short Circuit Power due to Synchronous Generators

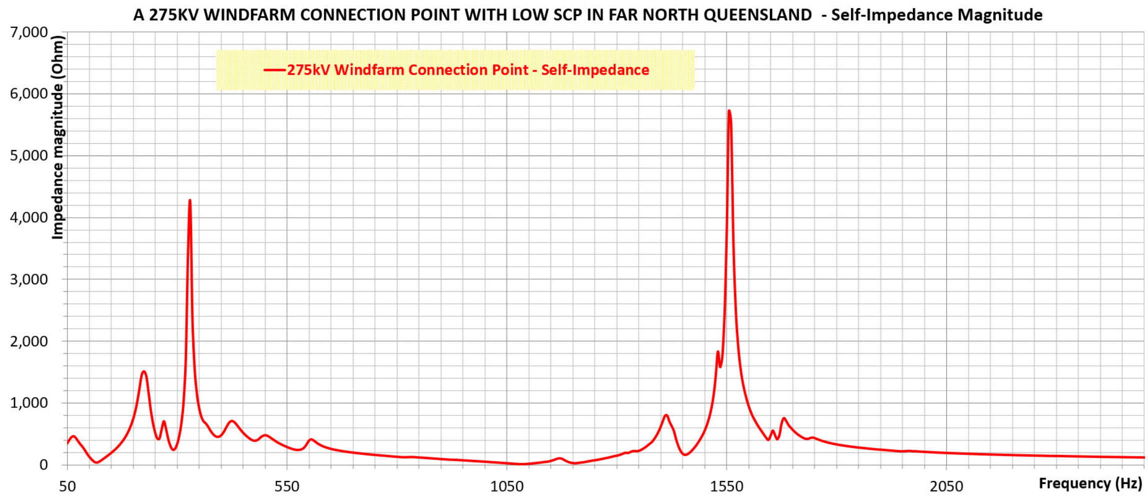


Figure 4.4 –Harmonic Impedance at a 275 kV Windfarm Connection Point in Far North Queensland, Australia with Low Short Circuit Power in Remote Network Area

It was observed that buses with high SCP at fundamental frequency would likely, but not always, have lower harmonic impedance magnitudes at high frequency compared to those of buses with lower SCP, i.e. there is no direct correlation between SCP and harmonic impedance magnitudes or resonance conditions in transmission systems. SCP for 22 network scenarios of the case study is shown below in Table 4.3.

Table 4.3 – 132 kV 7-Bus Transmission Network Case Study – Short Circuit Power in p.u.

Scenarios	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5	Bus 6	Bus 7
1	19.90	13.37	15.10	12.15	7.05	10.69	6.71
2	11.82	12.89	14.24	12.03	6.89	10.54	6.29
3	9.97	11.04	14.25	12.03	6.89	10.55	5.76
4	8.86	12.92	11.50	11.53	6.30	9.93	5.40
5	11.80	10.48	11.97	11.63	6.42	10.06	6.29
6	11.61	12.74	12.74	10.20	6.73	10.52	6.24
7	11.81	12.89	14.18	11.99	4.80	10.23	6.29
8	11.81	12.89	14.19	11.27	6.80	9.50	6.29
9	11.82	12.89	14.24	12.01	5.56	10.37	6.29
10	11.69	12.80	13.34	11.85	6.91	9.05	6.26
11	11.73	12.83	13.59	11.95	5.04	9.67	6.27
12	11.81	12.89	14.19	11.16	6.80	9.43	6.29
13	11.84	12.91	14.46	12.09	7.18	10.65	6.30
14	11.83	12.90	14.33	12.12	6.94	10.83	6.30
15	10.79	6.19	12.83	11.81	6.62	10.28	6.02
16	11.15	12.36	10.04	11.21	5.93	9.56	6.12
17	11.49	12.63	11.75	5.44	6.03	7.77	6.21
18	11.67	11.49	14.04	12.00	6.85	10.51	6.25
19	11.82	12.89	14.24	12.03	6.89	10.54	6.29
20	11.56	12.69	12.48	10.35	6.04	6.87	6.22
21	7.81	12.26	13.16	11.85	6.68	10.33	4.92
22	9.33	12.56	13.66	11.94	6.78	10.43	5.50

** SCP (p.u.): 1pu = 100 MVA (base)*
Key: ● SCP > 1200 MVA; ● 1200 MVA < SCP > 850 MVA; ● SCP < 850 MVA

From Table 4.3, it can be established that in general Bus 2 and Bus 3 are relatively high SCP buses. Bus 1, Bus 4 and Bus 6 are medium SCP buses, and Bus 5 and Bus 7 are of lower SCP. However, higher SCP buses, e.g. Bus 1, Bus 2, Bus 4 and Bus 6, all vary to levels as low as the lower SCP buses depending on network scenario. This highlights the dependency of impedance on network scenarios.

4.3.3 Harmonic Impedance under Network Reconstruction Stages

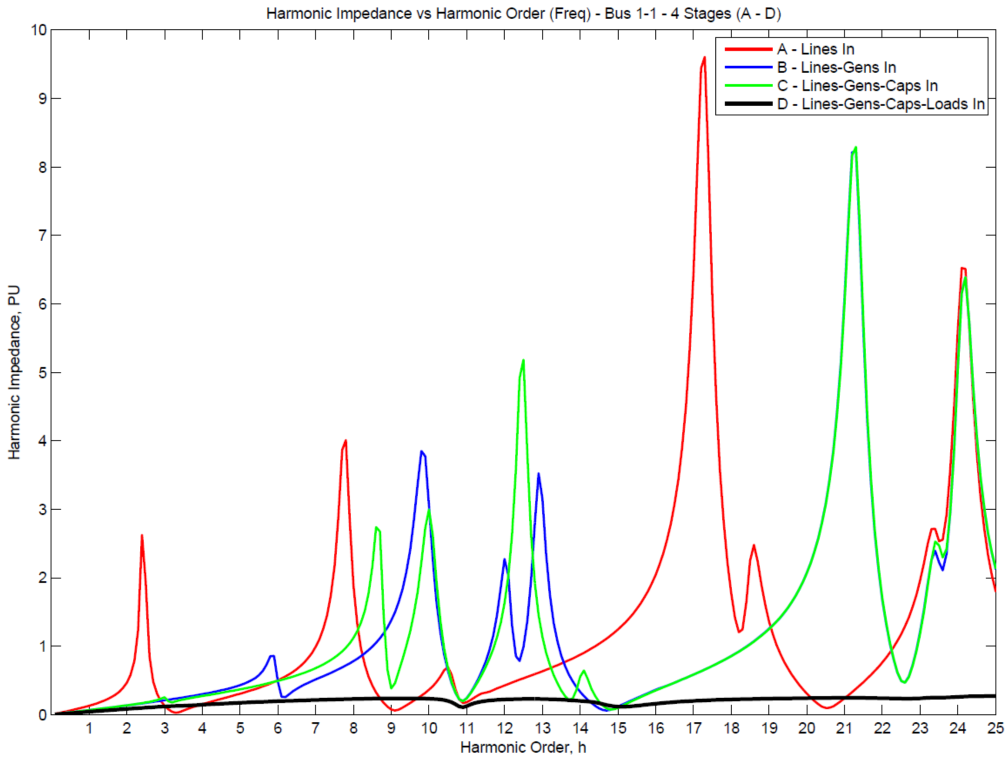
The 7-bus network in Figure 4.1 is reconstructed from individual network elements following stages (A) – (D) shown in Table 4.1. The main aim is to provide a better understanding of how network impedances vary with different combination of network elements, such as transmission lines, generators, capacitor banks and energy consumption loads, which are connected to the local (observed) buses. Harmonic impedances have been calculated and plotted to illustrate how characteristics change under the four reconstructive network scenarios. The self-impedance at Bus 1 and mutual impedances between Bus 1 and other buses have been plotted in Figure 4.5 (a) – (n). Changes of impedance at other busbars, e.g. Bus 3, show a similar trend are presented in Appendix B, Figure B.15 (a) – (n).

Characteristic impedances of the reconstructed transmission network no longer resemble those of any individual network elements examined above. It can be seen that transmission lines are major sources of multiple sharp harmonic resonances as shown in Figures 4.5 (a) – (n). Resonances occur with no other elements present, and the nature of these resonances change only in a second-order sense as other components are added. Self-impedance at Bus 1 in Figure 4.5 (a) displays sharp rises and falls in impedance over the frequency range for network stage (A), i.e. only lines are connected, due to long transmission lines. Resonant impedances are moderately attenuated as synchronous generators are added and resonant frequencies shifted toward the higher range. Adding Cap 5 and Cap 6, which are both tuned as 5^{th} harmonic filters help to reduce low-frequency impedances (around 5^{th} harmonic), but increase resonant impedances at frequencies above the tuned / detuned frequency of Cap 5 and Cap 6, e.g. between 11^{th} – 14^{th} harmonics, as shown in Figure 4.5. Depending on the series resonance frequency of the capacitor bank (i.e. resonant frequency between the capacitor bank and its series reactor), it contributes significantly to higher chances of parallel resonance at frequencies further away from its series resonance frequency. As the applied system model contained capacitor banks that were tuned to one low-order harmonic, no observations about the effect of connecting untuned shunt capacitor banks can be made. The model system does not aim to examine the effects of untuned shunt capacitor banks. On the other hand, synchronous generators provide good attenuation to resonant impedances. Likewise, energy consumption loads, which were modelled as aggregated CIGRE loads, provide very effective attenuation effects to harmonic impedances. The results showed that harmonic consumption loads provide very good attenuation effects to harmonic impedances. This does not happen in distribution systems where it seems to be a general rule that shunt loads are most effective where there are resonances. These are usually isolated over a narrow frequency range and due to a single identifiable capacitor bank. Both Figure 4.2 (Queensland Transmission Network) and Figure 4.5 (a) - (n) show that the transmission system has a harmonic resonance at nearly every harmonic frequency because of the multitude of lines of different lengths. It provides a reasonable explanation as to why the effect of loads on harmonic impedance attenuation is very significant in transmission systems.

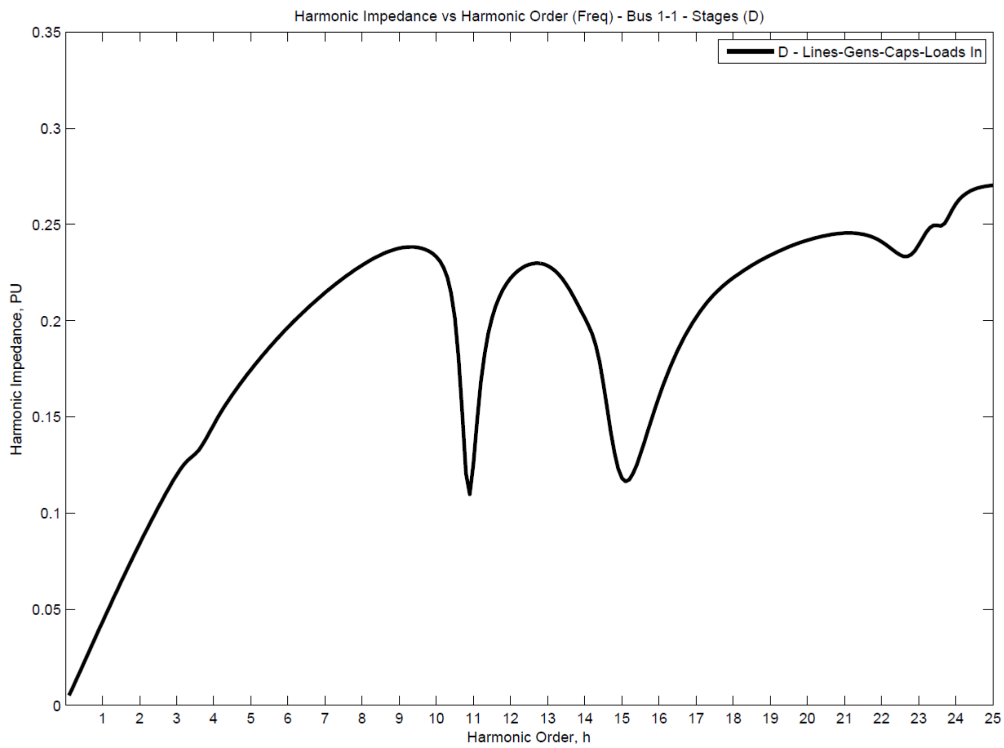
Under stage (C) of Table 4.1 (Lines, generators and capacitor banks are connected), Figure 4.5 (a) and (i) showed that that the *Influence Coefficient* between Bus 5 and Bus 1 at 7^{th} harmonic ($K_{5,1}(7) = Z_{1,5}(7) / Z_{1,1}(7)$) is approximately 1.3, which means that 1 p.u voltage injection at Bus 1 will result in approximately 1.3 p.u. at Bus 5. Much higher influence coefficients were observed at other buses, but not shown here. Variations of both self and mutual impedances depend on a different mix of network elements at different frequencies.

Impedance plots of the stage (D), i.e. with all network elements in service, in Figure 4.5 (a) – (n) showed that both network self-impedances and mutual impedances vary unpredictably as they heavily depend on the size, and combination of different type of network elements, especially transmission lines and capacitor banks, connected to busbars across the network. The complex characteristics of impedances at Bus 1, as shown in Figure 4.5, are also observed at other buses, e.g. at Bus 3 in Figure B.15 (a) – (n) in Appendix, and the Queensland transmission network impedances shown in Figure 4.2 – 4.4 above. Therefore, the application of the *Influence Coefficient* would be considered as the most appropriate method to capture the effects of network impedances on harmonic studies and allocation.

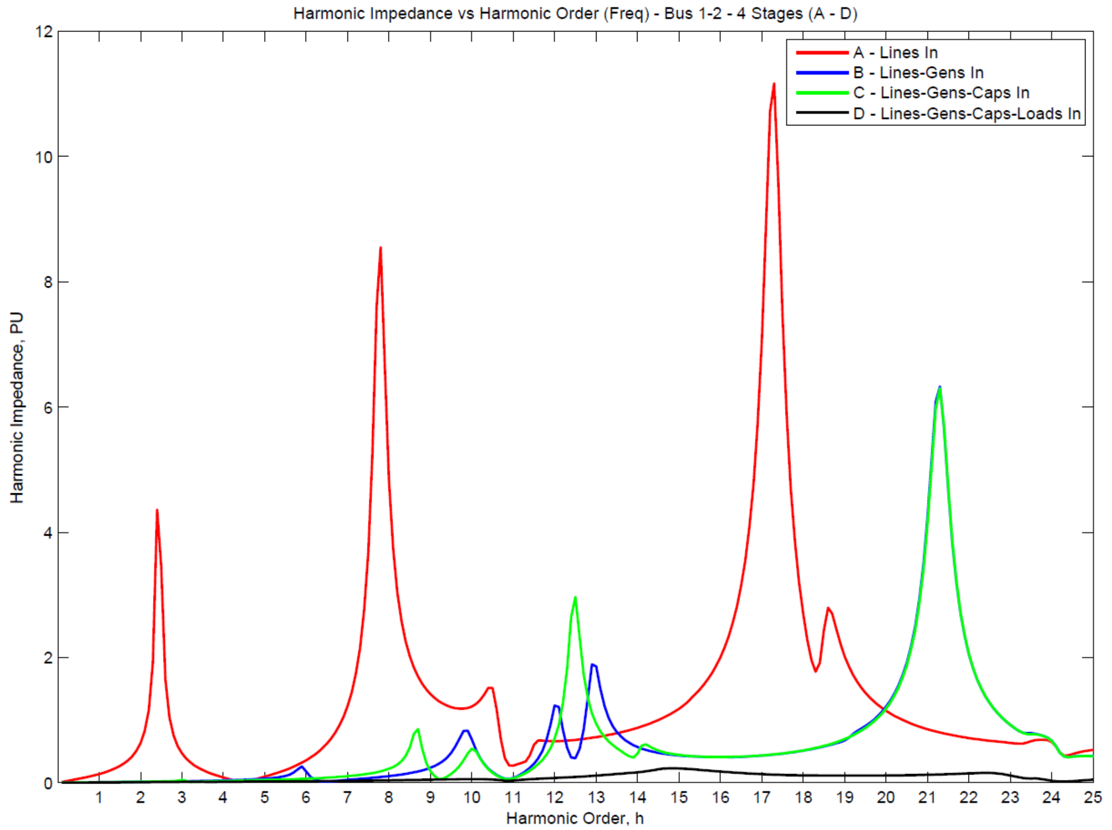
Impedances of Queensland transmission buses shown in Figures 4.2 – 4.4 and impedances of the stage (D) – all network elements of the case study network are in service – in Figures 4.5 (a) – (n) do not seem to resemble the impedance described in section 6.6 of CIGRE paper C4-401 [57]. This emphasizes the complexities of harmonic impedances, which are heavily influenced by a different mix of network elements under different network scenarios, in transmission systems.



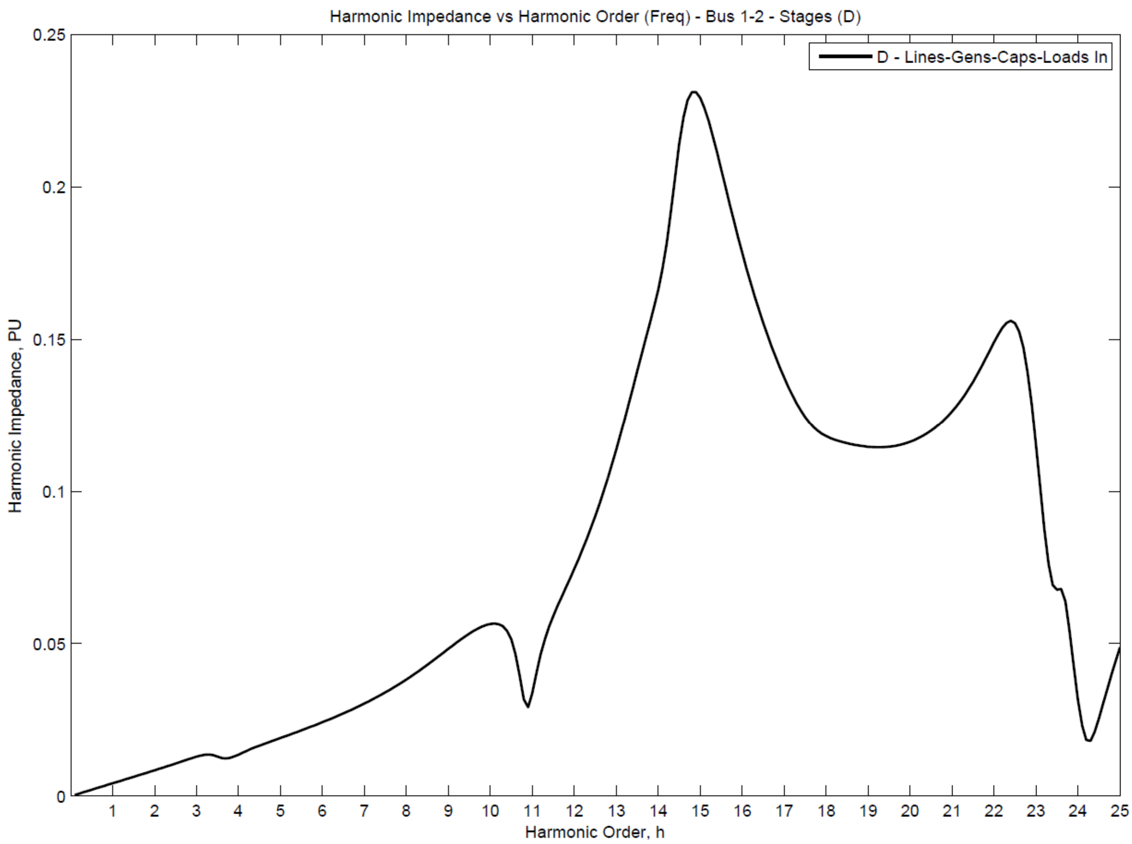
(a) Self-Impedance at Bus 1 – Stages (A-D) – Network Reconstruction Scenarios



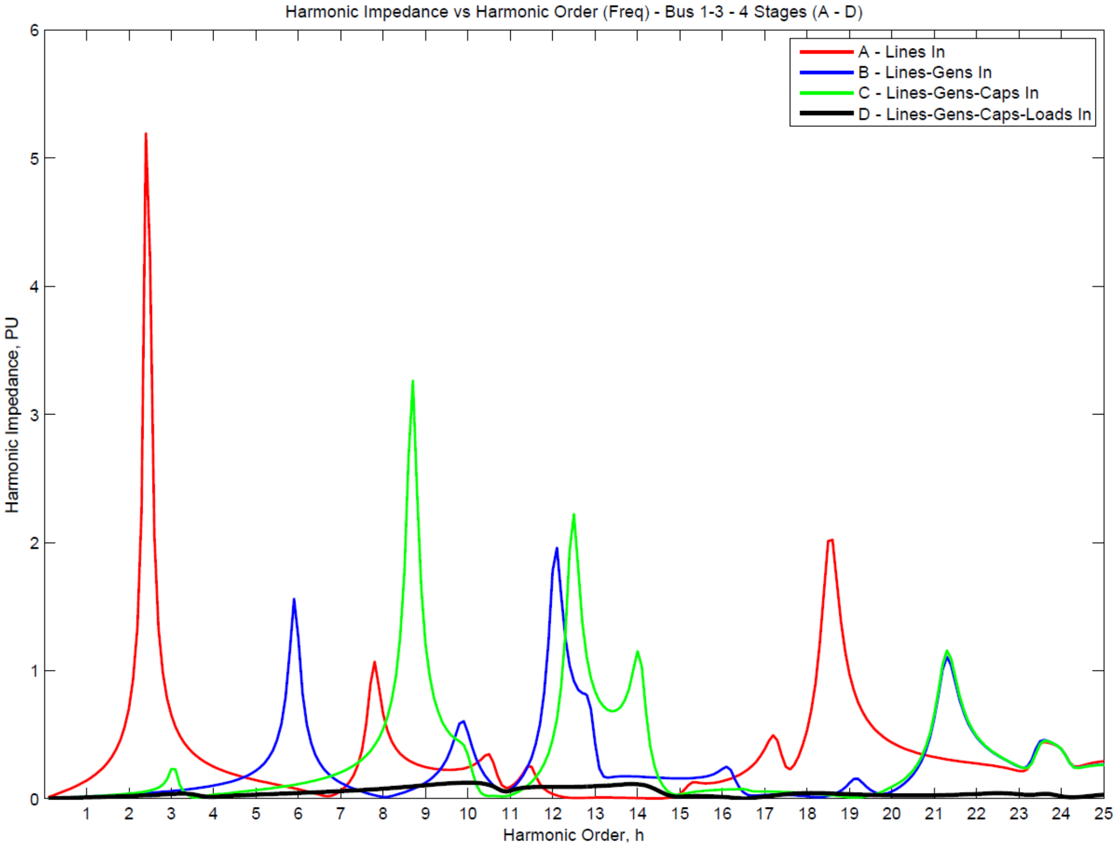
(b) Self-Impedance at Bus 1 – Stage (D) – All Network Elements are in Service



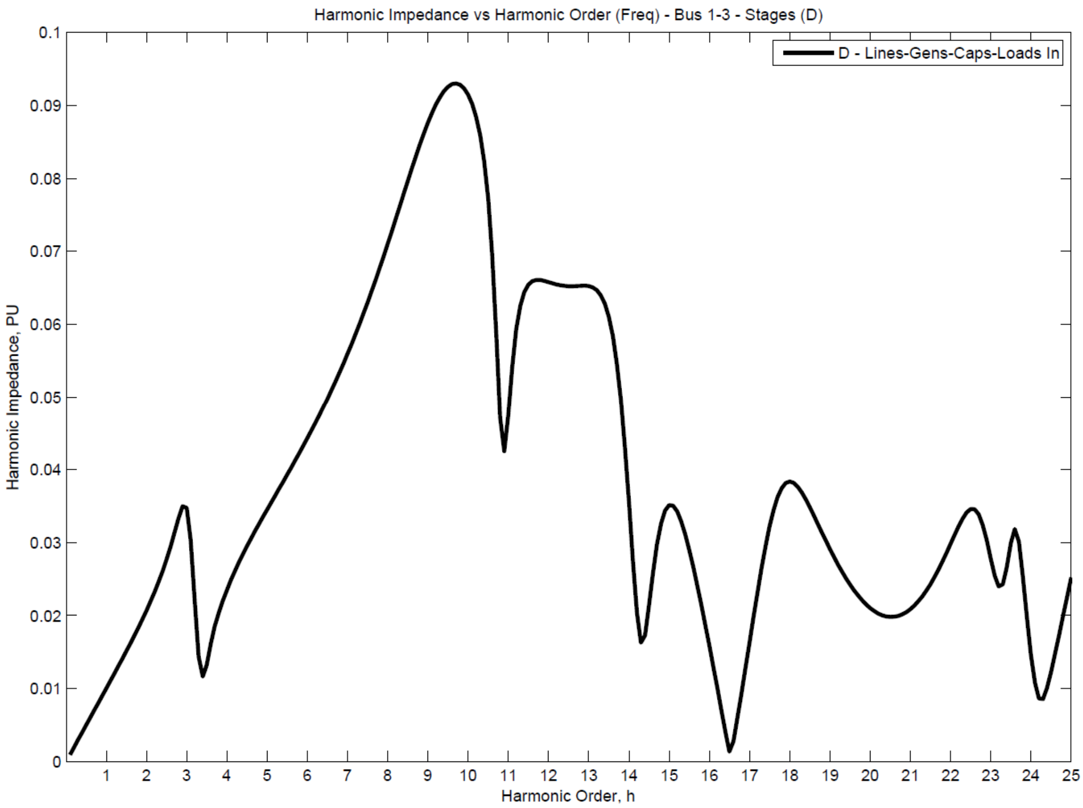
(c) Mutual Impedance between Bus 1 and Bus 2 – Stages (A-D) – Network Reconstruction Scenarios



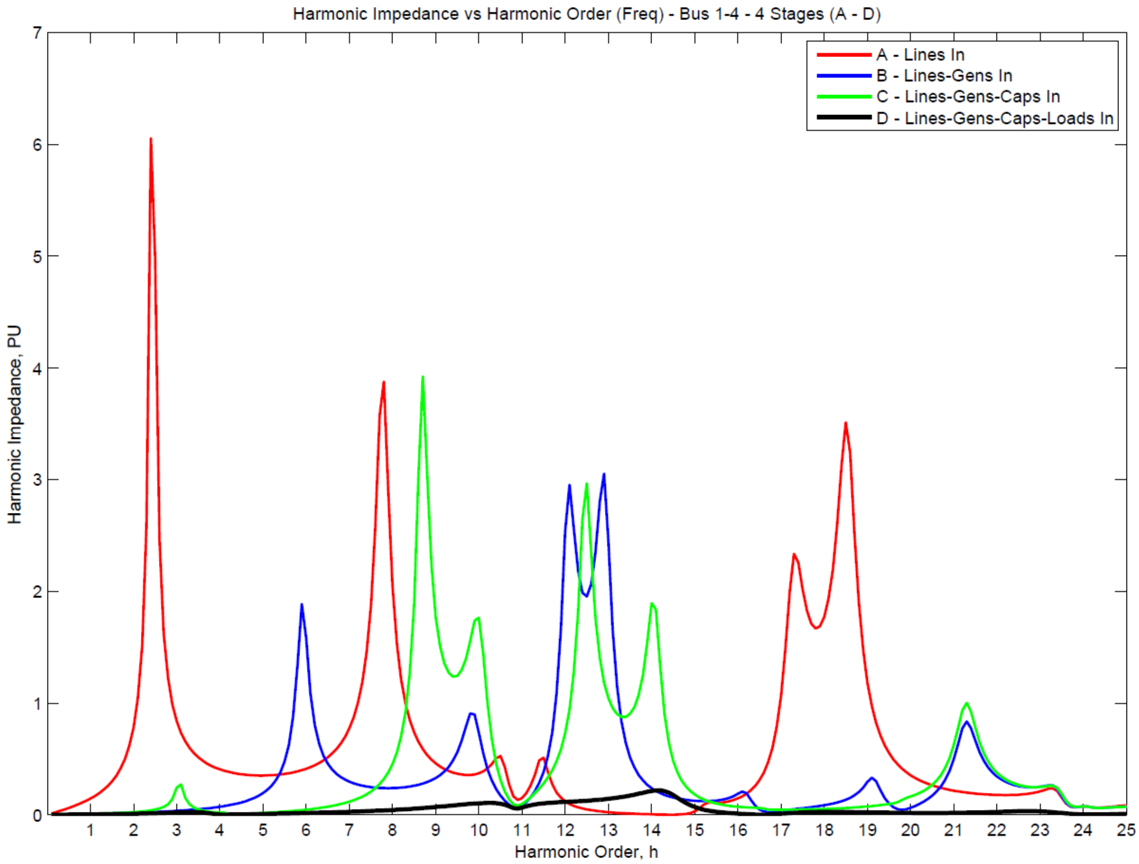
(d) Mutual Impedance between Bus 1 and Bus 2 – Stage (D) – All Network Elements are in Service



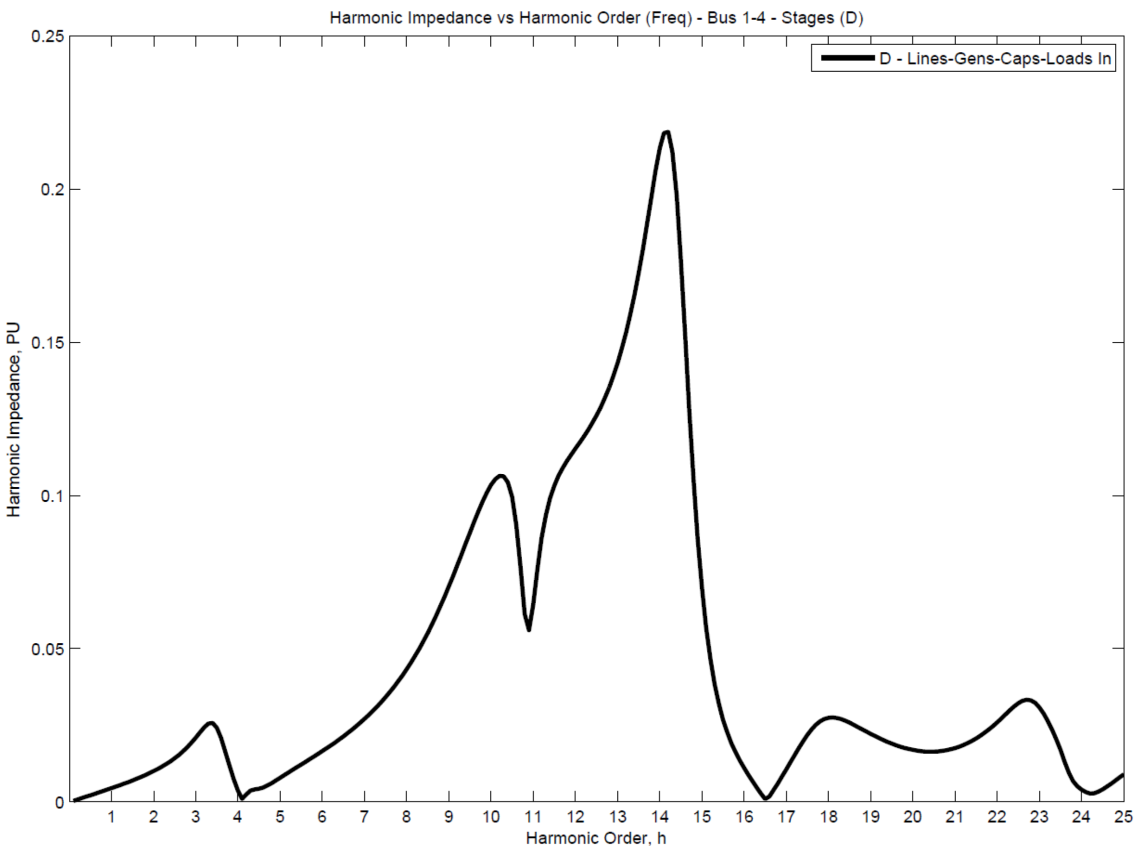
(e) Mutual Impedance between Bus 1 and Bus 3 – Stages (A-D) – Network Reconstruction Scenarios



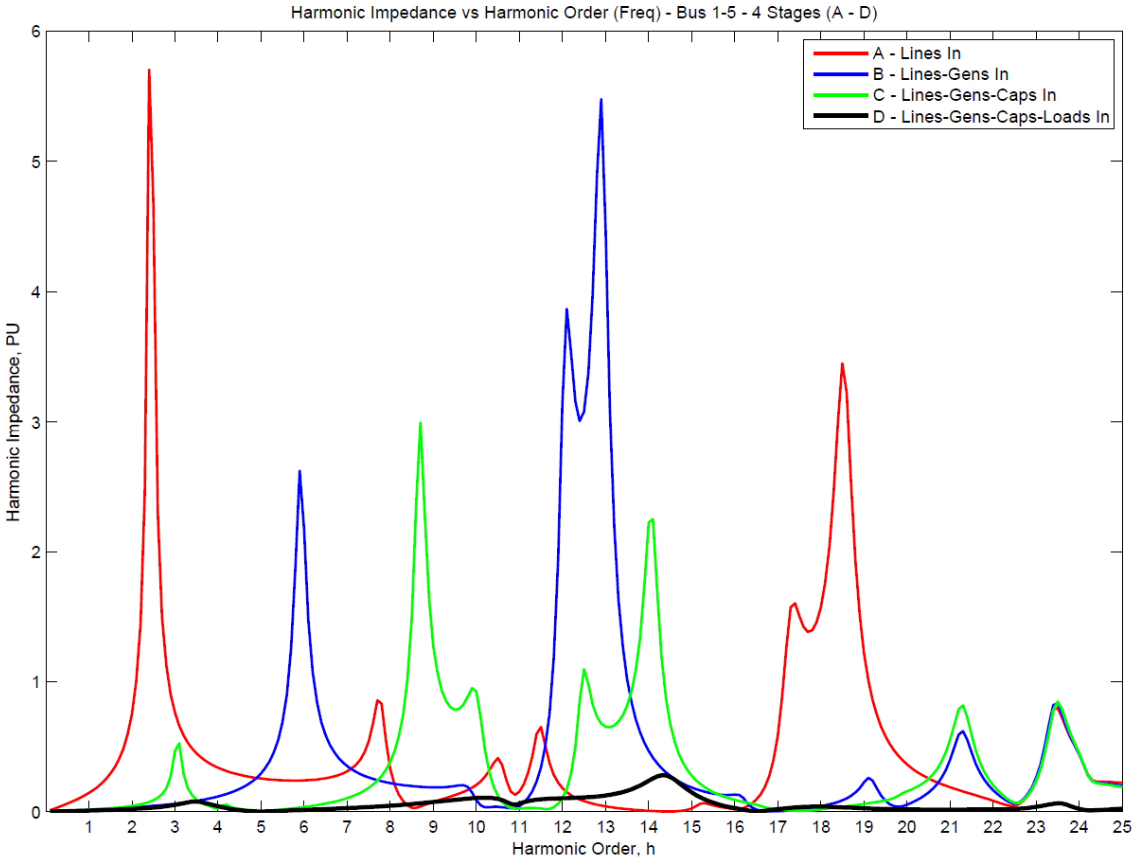
(f) Mutual Impedance between Bus 1 and Bus 3 – Stage (D) – All Network Elements are in Service



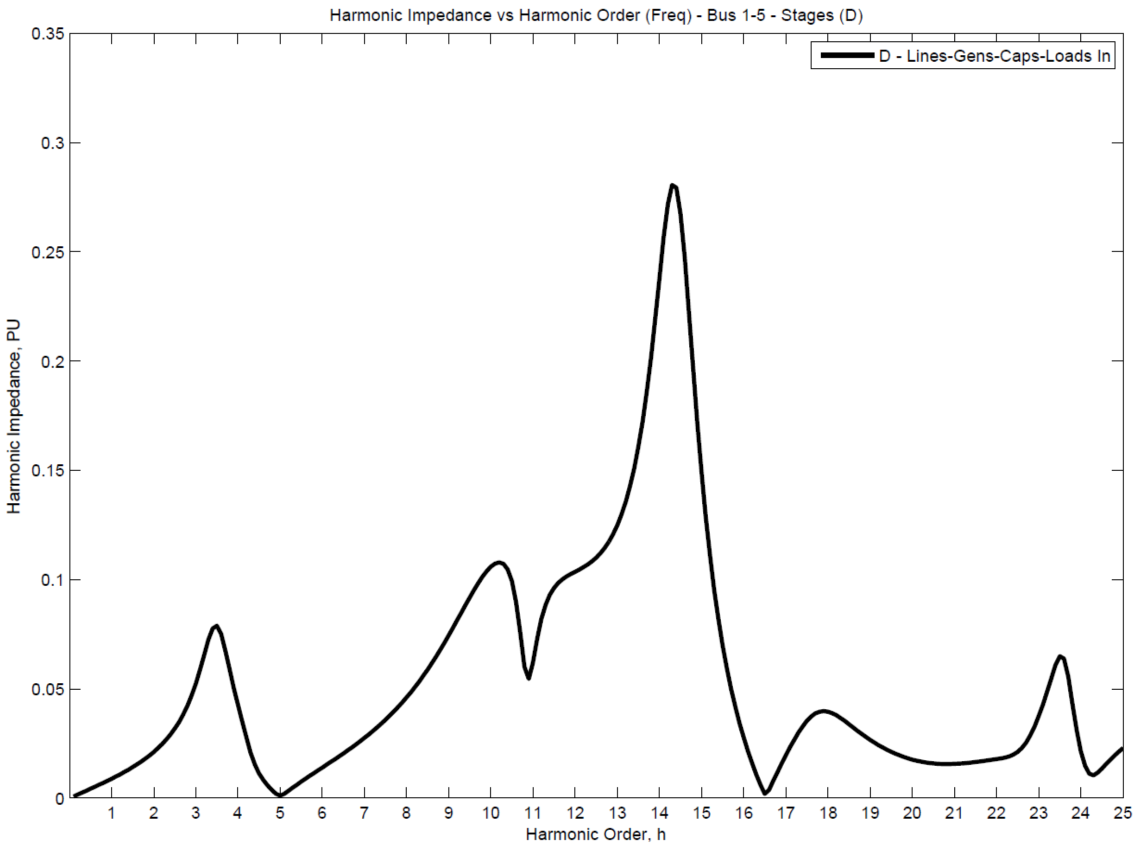
(g) Mutual Impedance between Bus 1 and Bus 4 – Stages (A - D) – Network Reconstruction Scenarios



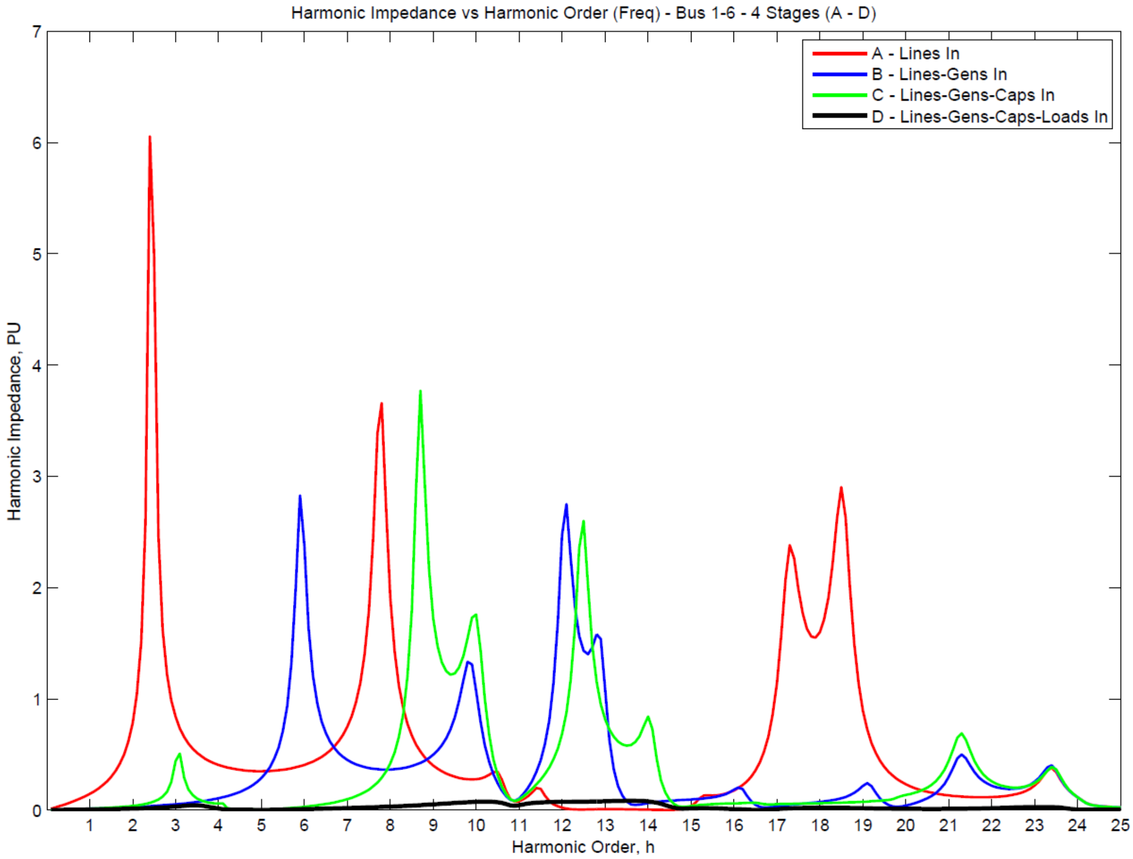
(h) Mutual Impedance between Bus 1 and Bus 4 – Stage (D) – All Network Elements are in Service



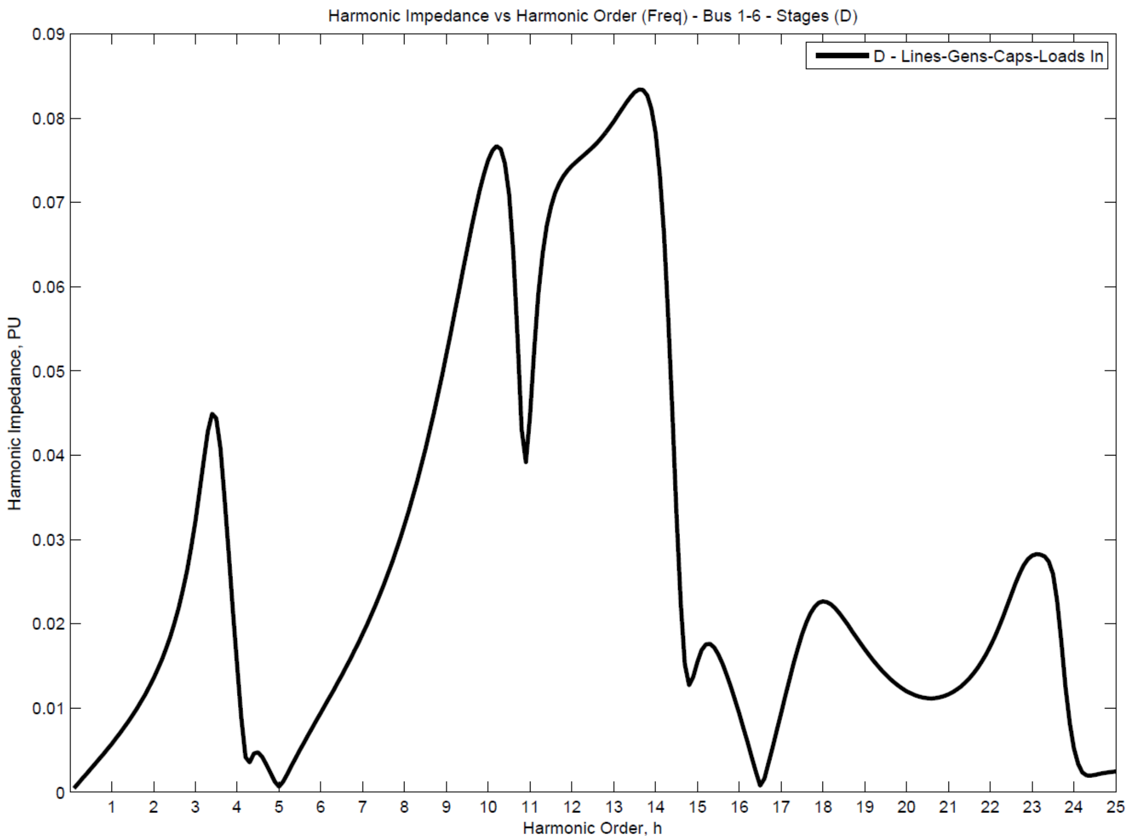
(i) Mutual Impedance between Bus 1 and Bus 5 – Stages (A - D) – Network Reconstruction Scenarios



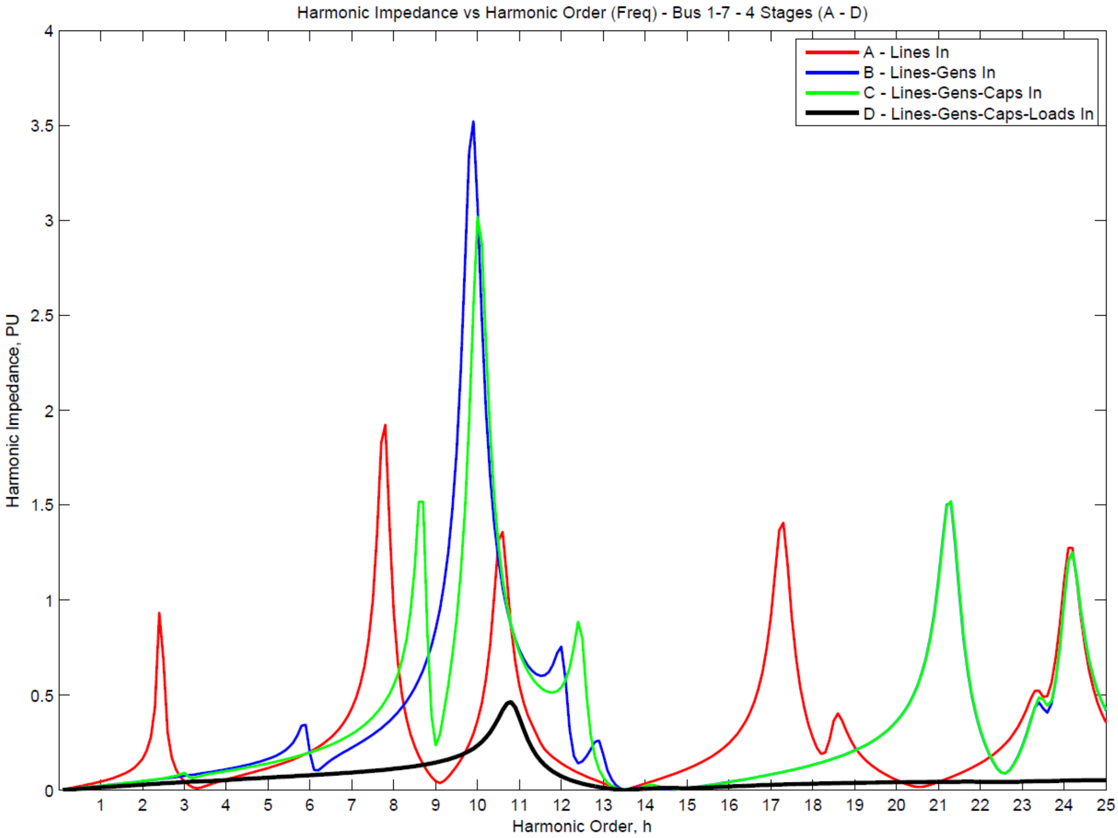
(j) Mutual Impedance between Bus 1 and Bus 5 – Stage (D) – All Network Elements are in Service



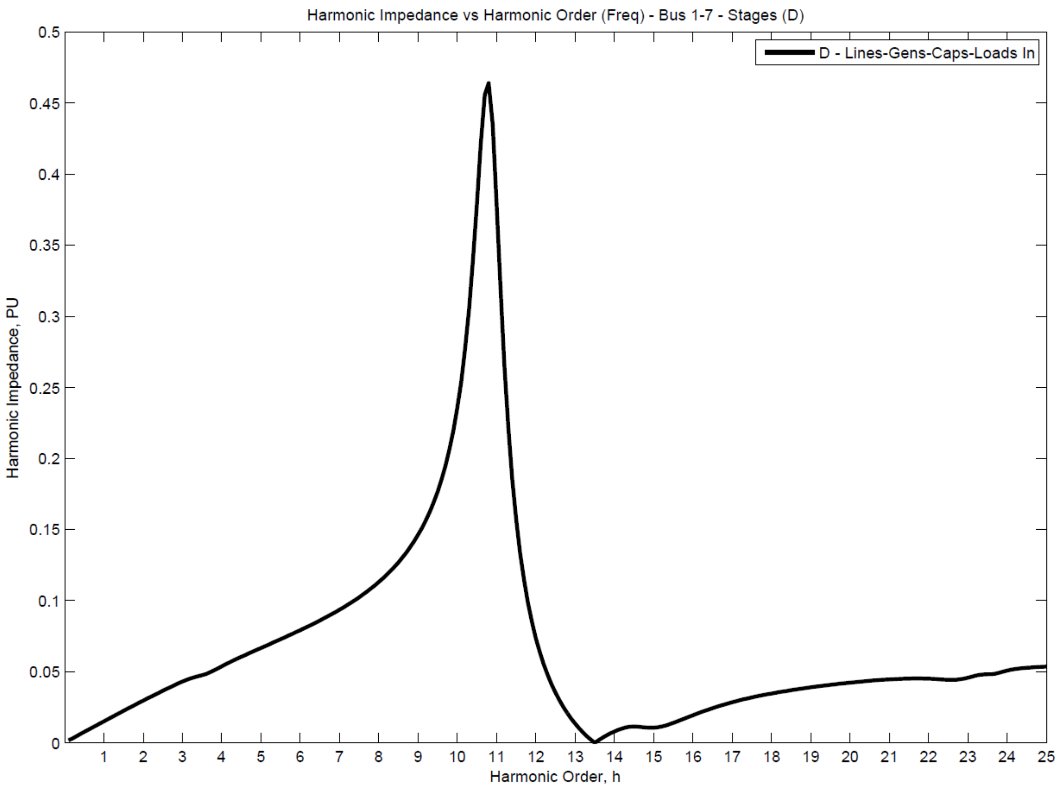
(k) Mutual Impedance between Bus 1 and Bus 6 – Stages (A - D) – Network Reconstruction Scenarios



(l) Mutual Impedance between Bus 1 and Bus 6 – Stage (D) – All Network Elements are in Service



(m) Mutual Impedance between Bus 1 and Bus 7 – Stages (A-D) – Network Reconstruction Scenarios



(n) Mutual Impedance between Bus 1 and Bus 7 – Stage (D) – All Network Elements are in Service0

Figure 4.5 – Harmonic Impedances ($Z_{i,j}(h)$) at Bus 1 - Reconstruction Network Scenarios

It can be summarised that results obtained from case studies in this research showed that changes of network harmonic impedances (self-impedance and mutual impedance) over the harmonic frequency spectrum is non-linear, complex and dependent on a different mix of network elements in the network. Attenuation effects on the network harmonic impedances shown in Figure 4.5 (a) – (n) are much more profound due to locally connected loads, compared to harmonic impedances shown in Figure 4.2 with remote load centres. It means that large industrial loads, e.g. mining loads, mineral processing plants, connected close to transmission systems buses should contribute noticeable attenuation effects to harmonic impedances at the local buses.

4.3.4 Parallel and Series Resonances

Large capacitor banks connected as shunt elements in transmission systems are one of the key contributing factors to network resonance conditions. Parallel resonance frequency between a capacitor bank and network inductance can be predicted using equation (2.10) in Chapter 2, rearranged below as equation (4.1).

$$h_{Par\_Res} = \sqrt{\frac{S_{SCP}}{Q_{Cap}}} \tag{4.1}$$

Where,

h_{Par_Res}: Harmonic order at which parallel resonance condition occurs.

S_{SCP}: Short Circuit Power calculated at the PCC where the capacitor bank is connected.

Q_{Cap}: Reactive Power of the capacitor bank.

<u>For example</u>: Under the system intact Scenario 1 of the network in Figure 4.1 where Bus 5 SCP = 7.05 p.u., whenever the voltage support capacitor bank (Cap 5 = 30 MVArs) is switched on at Bus 5, it would cause parallel resonance around 5th harmonic (h_{Par_Res} = 4.85). As a result, Cap 5 has been tuned as a 5th harmonic filter, shown in Figure 4.1, as well as a voltage support capacitor bank. Accordingly, the rating of capacitors and in-rush/tuning reactors need to be able to withstand additional harmonic currents. One of the benefits of tuning Cap 5 to 5th harmonic filter is that the 5th harmonic impedance at bus 5, where the filter is connected, will be reduced.

The maximum harmonic voltage at a local PCC, where a harmonic source is connected, can occur when a parallel resonance circuit is formed between a shunt capacitor bank connected to the same PCC and network inductance, e.g. a shunt reactor or a power transformer. Maximum harmonic amplification at a remote bus occurs when the *Influence Coefficient* between the local and remote bus is maximum (>>1). Maximum *Influence Coefficients* ($K_{j\text{-}i}(h)$) occur when a parallel resonance of a mutual impedance (*maximum* $Z_{i,j}(h)$) coincides with a series resonance of self-impedances (*minimum* $Z_{j,j}(h)$).

Series resonance circuit can be formed between a capacitor bank and network inductance. Series resonance creates a low impedance path for additional harmonic currents to flow between the capacitor bank and network inductive elements, e.g. a power transformer or a reactor. Series resonance impedance (i.e. minimum self-impedance) at a PCC gives rise to *Influence Coefficients* (ratio of mutual impedance over self-impedance) as discussed in Chapter 3.

Transmission utilities undertake harmonic frequency scanning to study harmonic impedances in their network. Network scenarios may vary from every scenario to a reduced subset, e.g. summer peak (very heavy load), winter peak (heavy load), summer light and winter light. This research project has also examined a large set of network impedance data from a transmission utility in Queensland Australia. It was observed that higher chances of parallel resonance are associated with heavy load conditions, e.g. as shown in Figure 4.2 (heavy load and a high number of transmission lines) compared to light load conditions under circumstances explained below.

Heavy load: Under heavy load condition, more generators are dispatched to supply higher load currents. All transmission lines are in service and capacitor banks are often switched in to support voltages at heavily loaded buses. More passive capacitive elements added to the network will lead to higher chances of parallel resonances between transmission lines, capacitor banks and network inductive elements.

Light load: Under light load condition, remote buses at the end of the line experience high voltage due to light load and capacitance of the lines, fewer transmission lines are in service and capacitor banks will be switched out hence lower chances of parallel resonance between capacitor banks and inductive network elements.

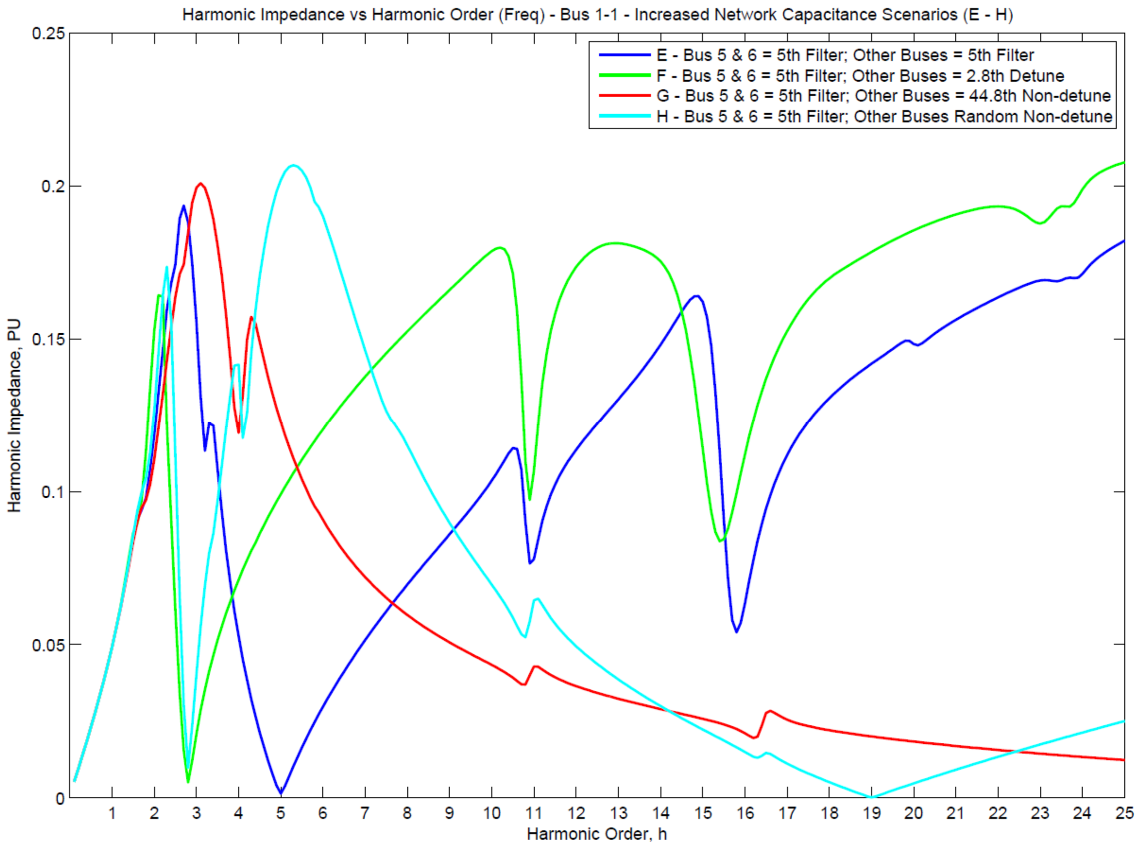
This information may be considered to help to reduce the number of light load network scenarios from harmonic allocation as they are less onerous, in terms of parallel resonance, compare to heavy load cases. However, planners need to be mindful that parallel resonance at a PCC is not the only cause of increased harmonic voltages, but also remote amplifications due to increases of *Influence Coefficients* attributed by the series resonance of self-impedance and/or parallel resonance of mutual-impedance as discussed above. For example: if a harmonic source is connected to a very strong PCC (*high SCP*) due to its proximity to synchronous generators, i.e. very low $Z_{j,j}(h)$, the chance of voltage amplification caused by this source to remote busbars will be much higher, compared to if it was connected to a weak PCC (*Low SCP*), i.e. very high $Z_{j,j}(h)$.

Voltage support capacitor banks are often connected to long/skinny transmission systems, e.g. Queensland transmission in Australia [64]. The effects of large capacitor banks on network harmonic impedances can be very significant depending on its installed location, SCP at its PCC and its interactions with other reactive plants, e.g. transformers and reactors. Another case study was conducted to examine the effects of different types of capacitor banks, e.g. tuned harmonic filters, detuned capacitor banks and non-detuned capacitor banks, on network harmonic impedances. In this case study, the network in Figure 4.1, with all network element in service (Stage D in Table 4.1), has been augmented to include an extra capacitor bank installed at every busbar. All new capacitor banks, except Cap 5 and Cap 6 were previously tuned to 5th harmonic filters in Stage D, are tuned/detuned differently under four scenarios: (i) tuned at 5th harmonic – scenario E; (ii) detuned at 2.8th harmonic (detuned at low frequency) – scenario F; (iii) detuned at 44.8th harmonic (arbitrarily detuned at high frequency) – scenario G; and (iv) non-detune (at random frequencies) – Scenario H. Case study network scenarios (E) – (F) are summarised in Table 4.4 below.

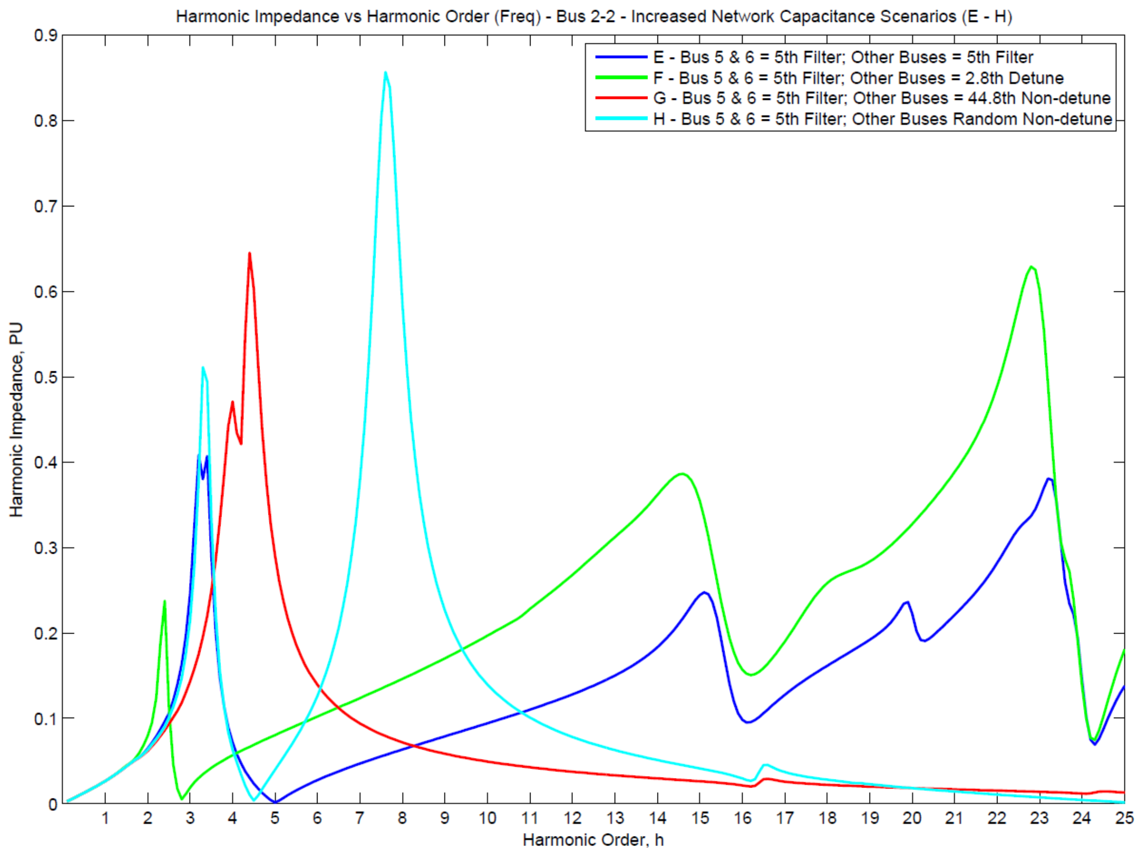
Self-impedances, under four network scenarios (E – H), are shown in Figure 4.6 (a) – (g) below. Parallel resonance impedances under scenarios E (tuned at 5th harmonic) and F (detuned at 2.8th harmonic), are less onerous at lower frequency range than at higher frequency range. In contrast, parallel resonance impedances under scenarios G (detuned at 44.8th harmonic) and H (non-detuned) are more onerous at a low frequency than at a higher frequency range. It can be summarised that tuned harmonic filters or detuned capacitor banks result in: (i) lower network parallel resonance impedance at frequencies closer to the capacitor bank tuned/detuned frequency; and (ii) higher network parallel resonance impedance at frequencies that are further away from their tuned/detuned frequency. Similar results are also observed for non-detuned capacitor banks depending on the series resonance frequency of capacitor banks and their installed locations.

Table 4.4 – Network Harmonic Impedance Case Study –Tuned, Detuned and Non-Detuned Capacitors

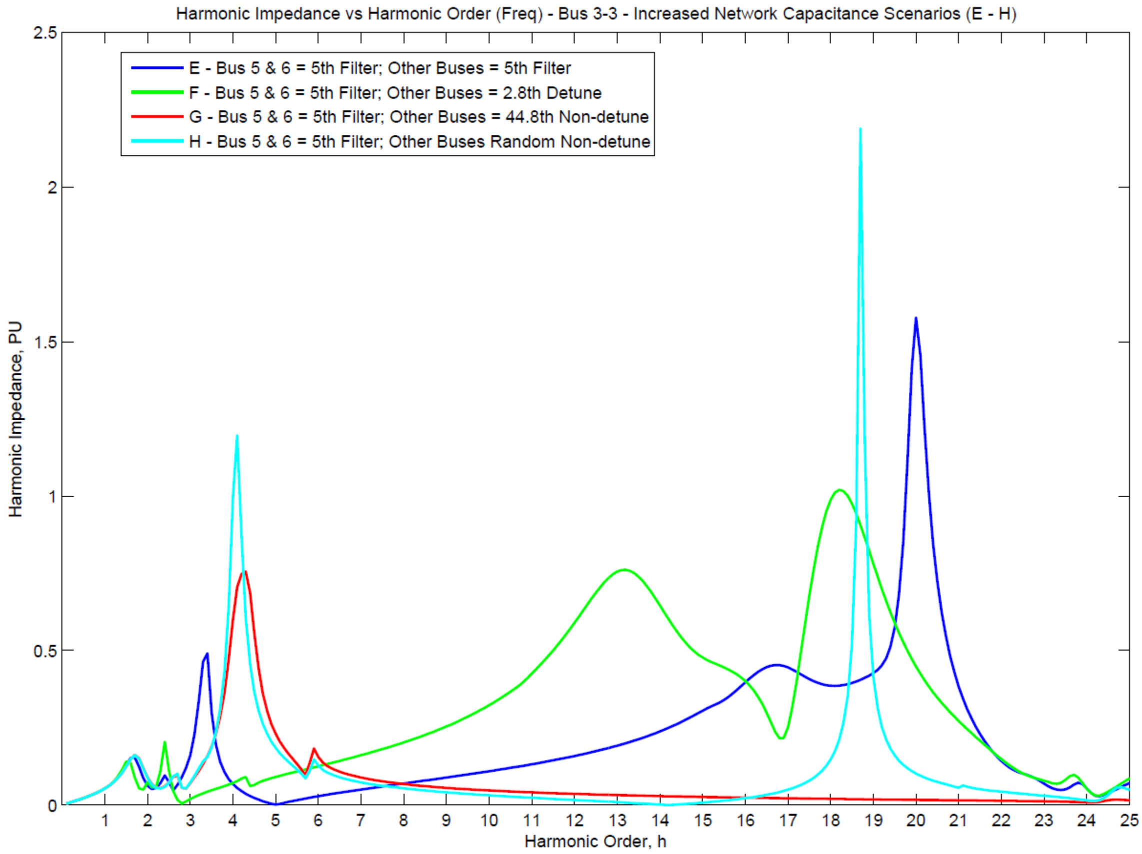
Network Scenarios	**Capacitor Banks at Tuned/Detuned/Non-detuned frequencies**						
	Bus1	**Bus2**	**Bus3**	**Bus4**	**Bus5**	**Bus6**	**Bus7**
(E) 5th Tuned	Cap1: 5th	Cap2: 5th	Cap3: 5th	Cap4: 5th	Cap5: 5th Cap8: 5th	Cap6: 5th Cap9: 5th	Cap7: 5th
(F) 2.8th Detune	Cap1: 2.8th	Cap2: 2.8th	Cap3: 2.8th	Cap4: 2.8th	Cap5: 5th Cap8: 2.8th	Cap6: 5th Cap9: 2.8th	Cap7: 2.8th
(G) 44.8th Detune	Cap1: 44.8th	Cap2: 44.8th	Cap3: 44.8th	Cap4: 44.8th	Cap5: 5th Cap8: 44.8th	Cap6: 5th Cap9: 44.8th	Cap7: 44.8th
(H) Non-Detune	Cap1: 2.8th	Cap2: 14.2th	Cap3: 15.8th	Cap4: 25.6th	Cap5: 5th Cap8: 41.1th	Cap6: 5th Cap9: 55.8th	Cap7: 68.6th



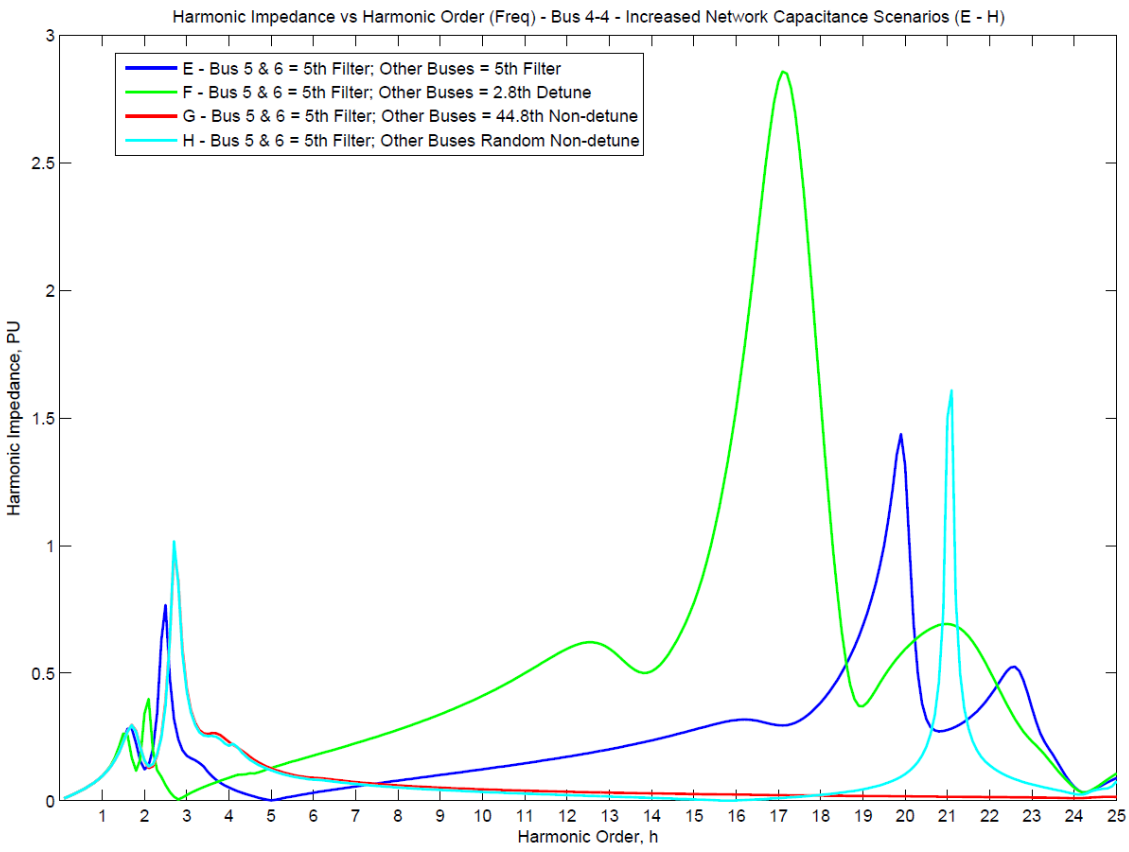
(a) Self-Impedance at Bus 1 $Z_{11}(h)$ – Capacitor Bank Scenarios (E – H)



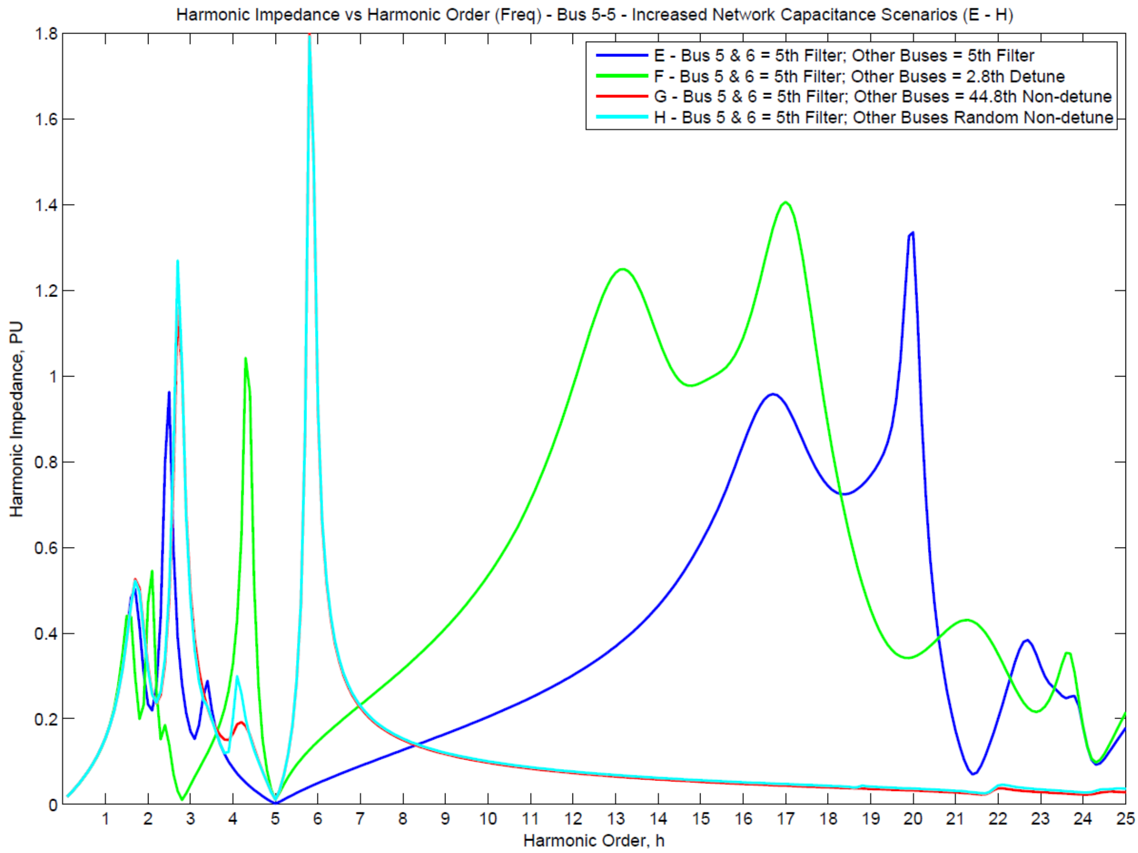
(b) Self-Impedance at Bus 2 $Z_{22}(h)$ – Capacitor Bank Scenarios (E – H)



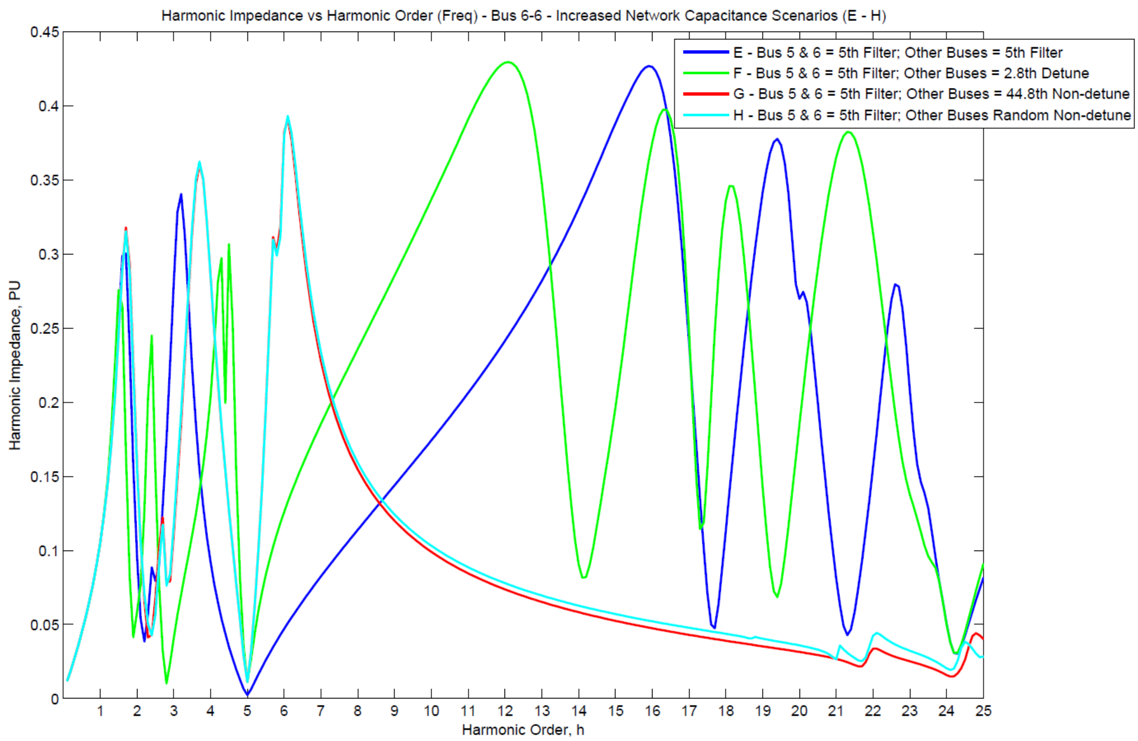
(c) Self-Impedance at Bus 3 $Z_{33}(h)$ – Capacitor Bank Scenarios (E – H)



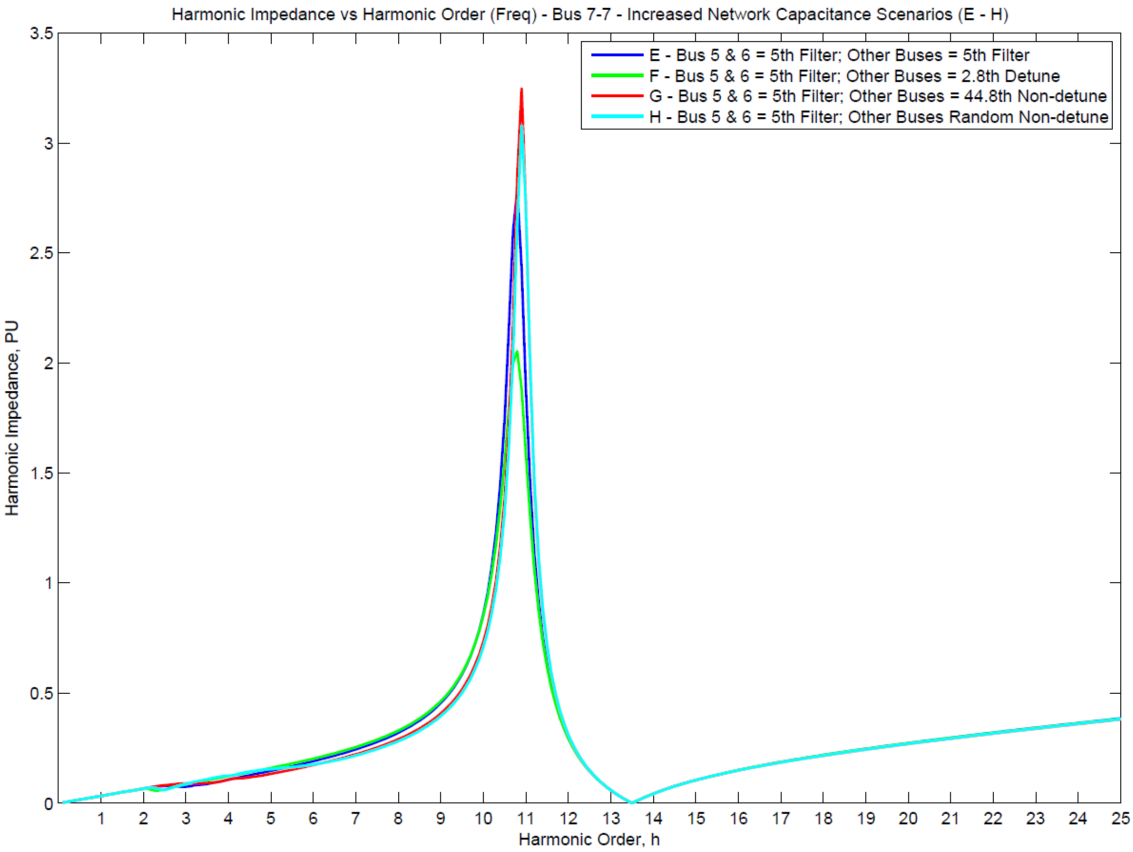
(d) Self-Impedance at Bus 4 $Z_{44}(h)$ – Capacitor Bank Scenarios (E – H)



(e) Self-Impedance at Bus 5 $Z_{55}(h)$ – Capacitor Bank Scenarios (E – H)



(f) Self-Impedance at Bus 6 $Z_{66}(h)$ – Capacitor Bank Scenarios (E – H)



(g) Self-Impedance at Bus 7 $Z_{77}(h)$ – Capacitor Bank Scenarios (E – H)

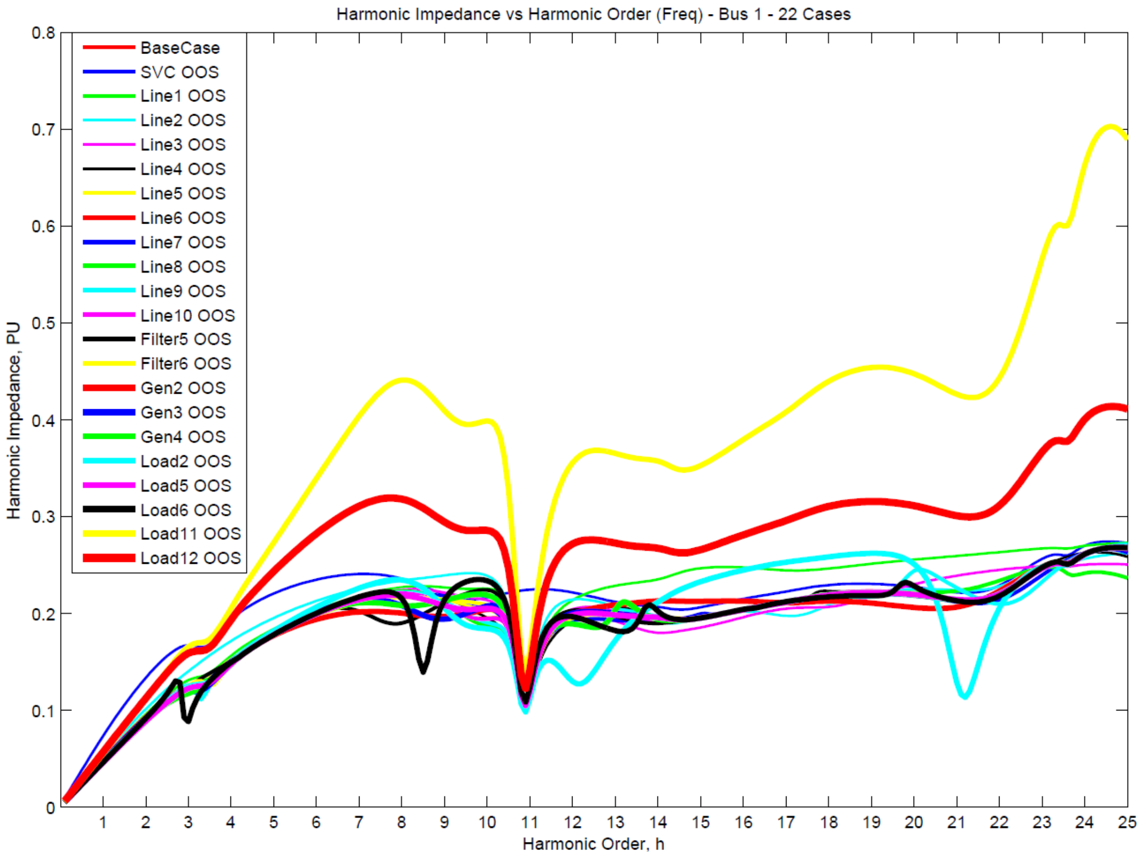
Figure 4.6 – Harmonic Self-Impedances ($Z_{j,j}(h)$) - Capacitor Bank Scenarios

Detuning every capacitor bank to a specific frequency, e.g. $h = 2.8$ (140 Hz) is expensive as detuning reactors must be individually sized to suit different capacitor banks. Furthermore, detuning a capacitor bank only helps to avoid high harmonic voltages at frequencies close to its detuned frequency at its connection point, but it still can form a parallel resonant circuit with the network inductance at other frequencies further away from its detuned frequency. The location of the capacitor bank, its series resonance frequency (or tuned/detuned frequency) and network short circuit power at the connection point play a key role in resonance condition as per the example and case study above. There is no evidence to support that detuning all voltage support capacitor banks in a transmission network will help reducing harmonic voltages, across the harmonic spectrum, at all buses. Depending on the installed location of that capacitor bank, SCP at its PCC, and its series resonance frequency, the opposite effects can also occur due to resonance conditions between capacitor banks and nearby inductive elements at other frequencies as demonstrated in the case study above.

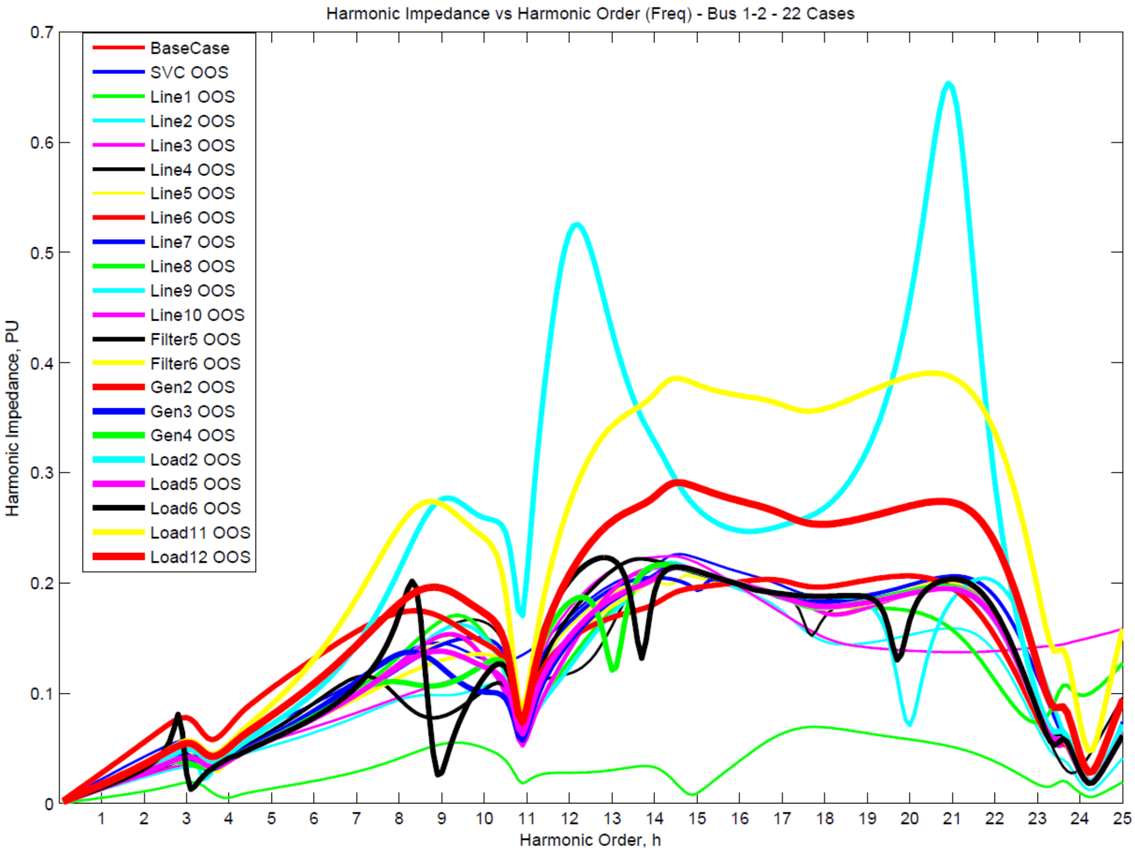
4.3.5 Harmonic Impedance under (N-1) Practical Network Contingency Scenarios

Harmonic impedances of the 7-bus transmission network in Figure 4.1 are examined under (N-1) network contingency scenarios listed in Table 4.2. In practice, many additional network scenarios exist, however, the study was limited to 22 contingency cases, selected in conjunction with experts from the relevant utility. Network harmonic impedances ([7x7] impedance matrix) have been determined and plotted to illustrate how characteristics vary from one network scenario to another. Only self-impedance at Bus 1 and mutual impedances between Bus 1 and other buses have been shown in Figure 4.7 (a) – (g) below. Other buses, e.g. Bus 3, show a similar trend are presented in Figure B.16 (a) – (g) in Appendix.

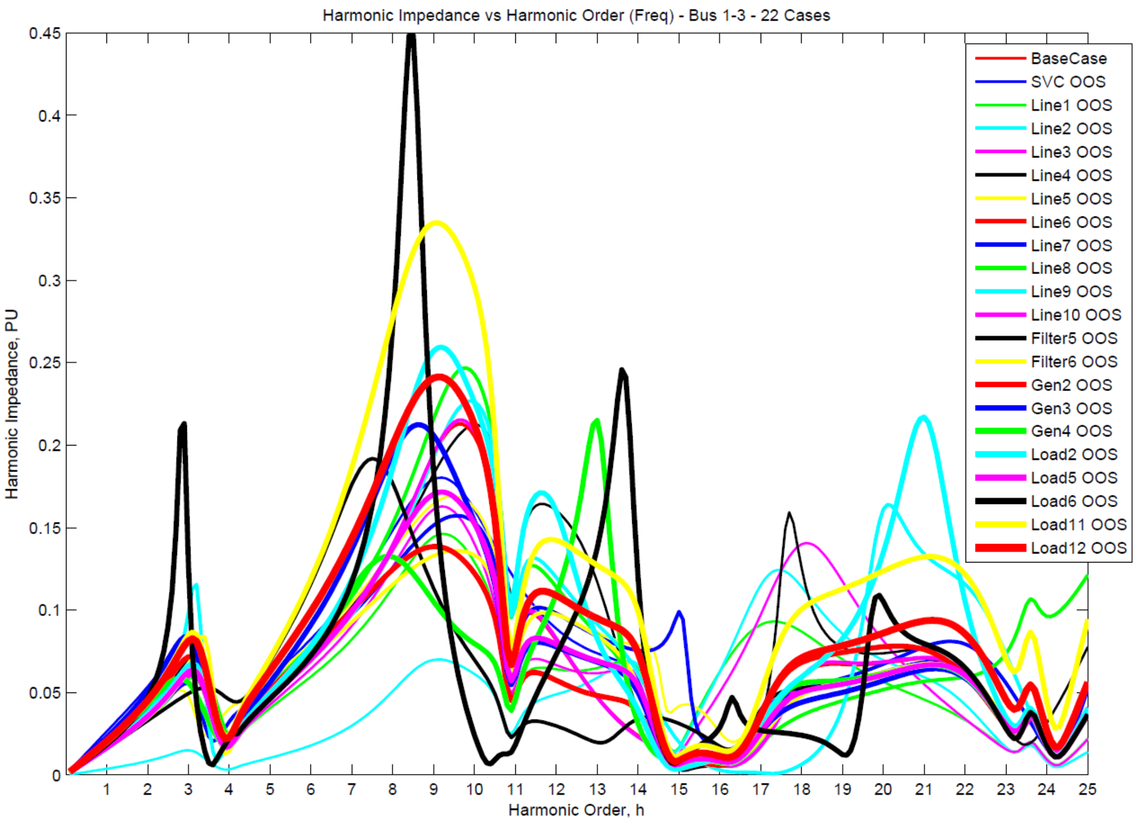
These graphs showed that magnitudes of harmonic impedances increase significantly under scenarios that loads are out of service. Given the high chances of parallel resonance conditions under heavy load network scenario as discussed above, the inclusion of energy consumption load models should be mandatory as it provides effective attenuation effects to harmonic impedances. These results also emphasise the importance of including appropriate load models in harmonic studies for transmission systems.



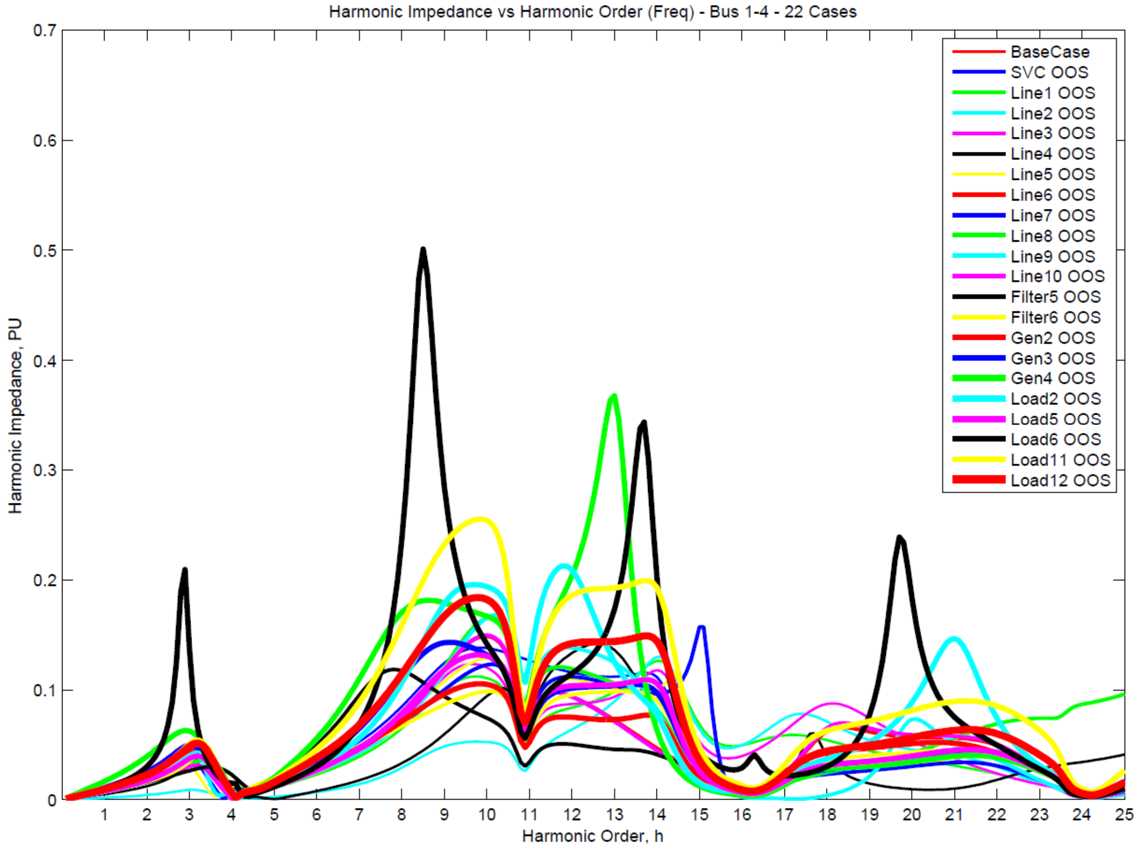
(a). Self-Impedance ($Z_{11}(h)$) at Bus 1 – 22 Network Scenarios (N-1)



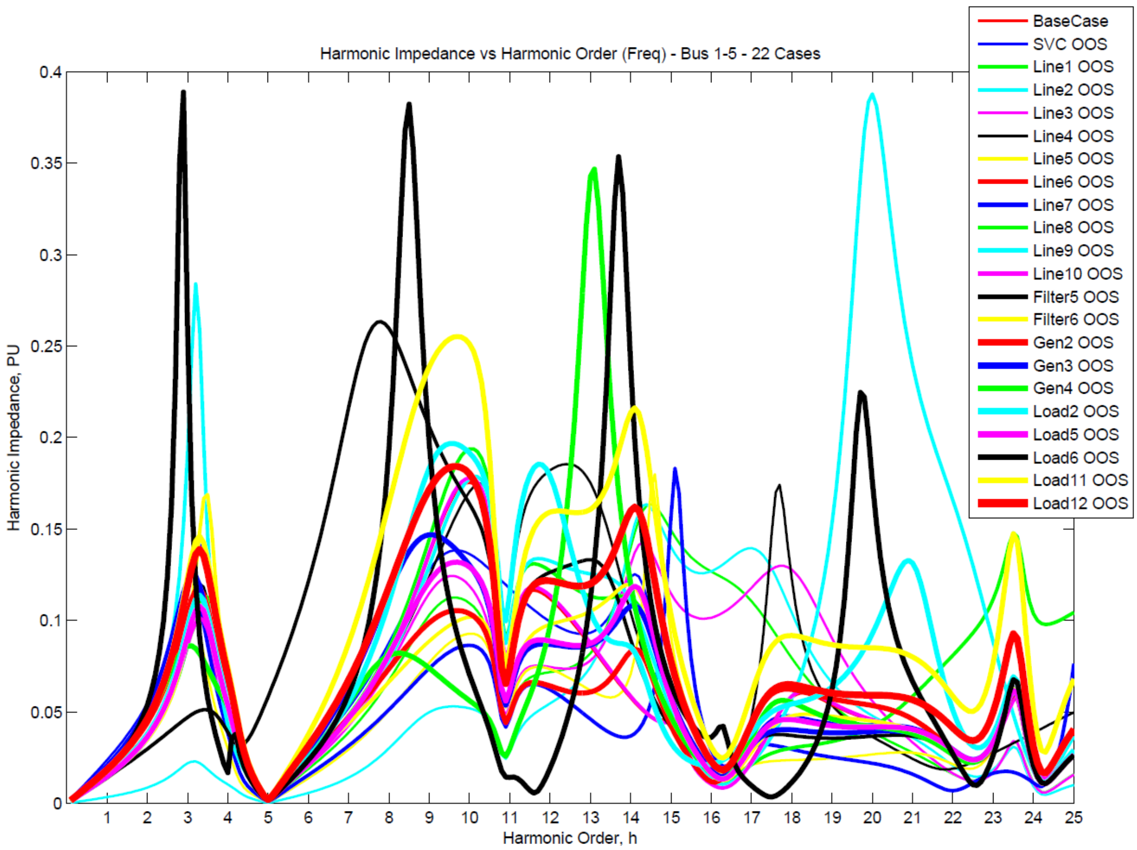
(b). Mutual-Impedance ($Z_{12}(h)$) Between Bus 1 and Bus 2 – 22 Network Scenarios (N-1)



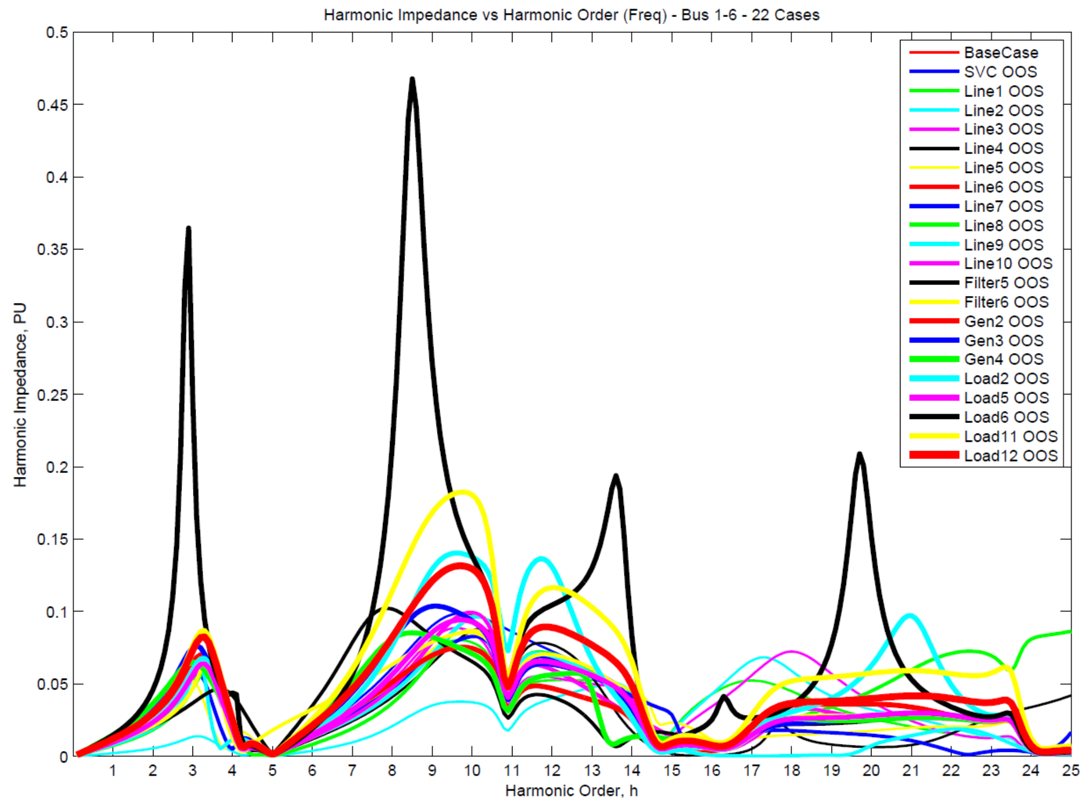
(c). Mutual-Impedance ($Z_{13}(h)$) Between Bus 1 and Bus 3 – 22 Network Scenarios (N-1)



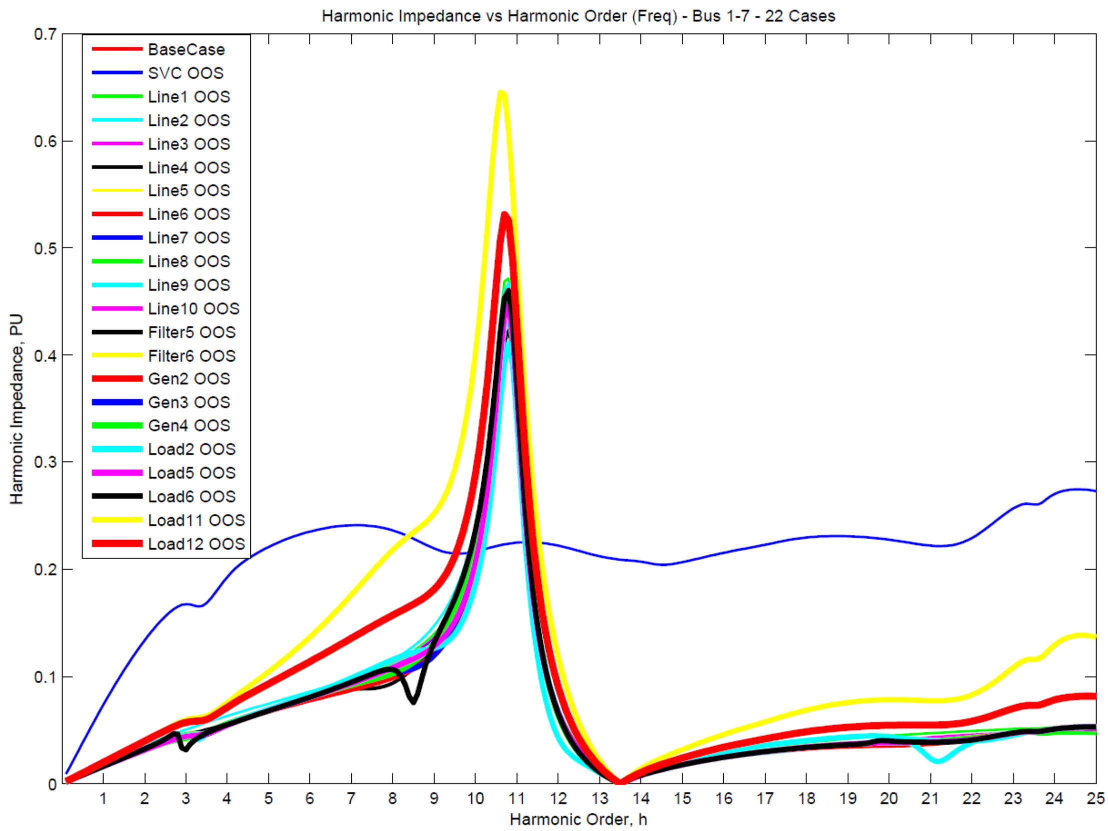
(d). Mutual-Impedance ($Z_{14}(h)$) Between Bus 1 and Bus 4 – 22 Network Scenarios (N-1)



(e). Mutual-Impedance ($Z_{15}(h)$) Between Bus 1 and Bus 5 – 22 Network Scenarios (N-1)



(f). Mutual-Impedance ($Z_{16}(h)$) Between Bus 1 and Bus 6 – 22 Network Scenarios (N-1)



(g). Mutual-Impedance ($Z_{17}(h)$) Between Bus 1 and Bus 7 – 22 Network Scenarios (N-1)

Figure 4.7 – Harmonic Impedances ($Z_{ij}(h)$) at Bus 1 - (n-1) Network Contingency Scenarios

4.3.6 Maximum Harmonic Impedances under (N-1) Practical Network Contingency Scenarios

Maximum self-impedances and mutual impedances of the 7 bus transmission network have been obtained from the 22 network contingency scenarios and recorded in Table 4.5 below. Specific network scenarios and frequencies corresponding with these maximum impedances have also been recorded in this table.

The results show that maximum harmonic impedances are associated with network scenarios that have loads Out Of Service (OOS). In this case study, loads were modelled using the CIGRE model, which becomes more inductive at high frequency as discussed previously. This supports the findings earlier that energy consumption loads provide very effective attenuation effects to network harmonic impedances.

The main purpose of Table 4.5 below is to demonstrate how impedances vary under different network scenarios. The main challenge for harmonic allocation methods, such as the IEC report, that rely on network impedances is the impacts on *Influence Coefficients* that are used in harmonic allocations methodology as discussed in Chapter 3. Results in Table 4.5 cannot be used to calculate *influence coefficients* as they show maximum impedance values from different network scenarios. *Influence coefficients* must be calculated for each network scenario, based on the corresponding self and mutual impedances. This brings another question as allocation of which network scenario is most suitable for the connecting load. Chapter 8 will develop a new methodology to select allocations, from a large number of network scenarios to best fit load requirements.

Table 4.5 – Network Harmonic Impedance Case Study – Network Scenarios

Network Impedance	Z_{11}	Z_{12}	Z_{13}	Z_{14}	Z_{15}	Z_{16}	Z_{17}
Max Magnitude (pu)	0.42	0.59	0.23	0.28	0.25	0.28	0.42
Element OOS, @ h order	Load 11, 25^{th}	Load 2 , 21^{st}	Load 6, 7^{th}	Load 6, 13^{th}	Load 6, 13^{th} Line 9, 20^{th}	Load 6, 8^{th}	Load 11, 11^{th}
Network Impedance	Z_{21}	Z_{22}	Z_{23}	Z_{24}	Z_{25}	Z_{26}	Z_{27}
Max Imp (pu)	0.59	0.31	1.15	1.25	1.4	0.77	0.57
Element OOS, @ h order	Load 2, 21^{st}	Load 2, 21^{st}	Load 2, 21^{st}	Load 6, 13^{th}	Load 6, 13^{th} Line 9, 20^{th}	Load 6 , 13^{th} Load 2, 12^{th}	Load 2, 11^{th}
Network Impedance	Z_{31}	Z_{32}	Z_{33}	Z_{34}	Z_{35}	Z_{36}	Z_{37}
Max Imp (pu)	0.23	1.15	3.75	3.1	3.5	3.2	0.24
Element OOS, @ h order	Load 6, 7^{th}	Load 2, 21^{st}	Load 6, 16^{th}	Load 6, 16^{th}	Load 6, 16^{th}	Load 6, 16^{th}	Load 2, 11^{th} Line 2, 11^{th}
Network Impedance	Z_{41}	Z_{42}	Z_{43}	Z_{44}	Z_{45}	Z_{46}	Z_{47}
Max Imp (pu)	0.28	1.25	3.1	1.5	9	3.1	0.25
Element OOS, h order	Load 6, 13^{th}	Load 6, 13^{th}	Load 6, 16^{th}	Load 6, 15^{th} Line 10, 15^{th}	Load 6, 15^{th} Line 10, 15^{th}	Load 6, 16^{th}	Gen 4, 11^{th} Load 2, 11^{th}
Network Impedance	Z_{51}	Z_{52}	Z_{53}	Z_{54}	Z_{55}	Z_{56}	Z_{57}
Max Imp (pu)	0.25	1.4	3.5	9	11.5	2.5	0.3
Element OOS, @ h order	Load 6, 13^{th} Line 9, 20^{th}	Load 6, 13^{th} Line 9, 20^{th}	Load 6, 16^{th}	Load 6, 15^{th} Line 10, 15^{th}	Line 5, 14^{th}	Load 6, 13^{th} Load 6, 16^{th}	Load 2, 11^{th} Line 1, 11^{th}
Network Impedance	Z_{61}	Z_{62}	Z_{63}	Z_{64}	Z_{65}	Z_{66}	Z_{67}
Max Imp (pu)	0.28	0.77	3.2	3.1	2.5	2.65	0.225
Element OOS, @ h order	Load 6, 8^{th}	Load 6 , 13^{th} Load 2, 12^{th}	Load 6, 16^{th}	Load 6, 16^{th}	Load 6, 13^{th} Load 6, 16^{th}	Load 6, 16^{th}	Load 2, 11^{th}
Network Impedance	Z_{71}	Z_{72}	Z_{73}	Z_{74}	Z_{75}	Z_{76}	Z_{77}
Max Imp (pu)	0.42	0.57	0.24	0.25	0.3	0.225	1.95
Element OOS, @ h order	Load 11, 11^{th}	Load 2, 11^{th}	Load 2, 11^{th} Line 2, 11^{th}	Gen 4, 11^{th} Load 2, 11^{th}	Load 2, 11^{th} Line 1, 11^{th}	Load 2, 11^{th}	SVC, 25^{th}

4.4 Impact of Network Scenarios on Harmonic Impedances and Allocations in Transmission Systems

As described earlier, harmonic impedances are one of the key contributors to the increases or decreases of harmonic voltages in the network. When using the IEC's summation law and alpha constants, impedance angles (and current angles) can be omitted to simplify the calculation of harmonic voltages. Therefore, changes in harmonic impedance magnitudes under different network scenarios would have significant impacts on harmonic allocations and harmonic voltage performance in the network.

In this project, harmonic allocation (voltage and current) was carried out based on the IEC's method for all loads (Load 2, 5, 6, 11 and 12) under 22 network scenarios. In all cases, the "Method of sharing planning levels and allocating emission limits in meshed HV-EHV systems", as described in Annex D of [10], were applied to ensure that harmonic voltages at all buses not exceeding the recommended planning levels for transmission systems in [10].

To simplify the allocation process, it was assumed that all loads (Loads 2, 5, 6, 11 and 12) are connected to the case study network at the same time. In practice, these loads would often be connected to the network at different points in time under different network scenarios and hence allocation should be undertaken according to that sequence.

In this case study, the SVC was installed previously, hence its allowable harmonic currents were previously allocated and would remain the same under all network scenarios, except for one scenario that the SVC is out of service. SVC's harmonic currents represent an existing harmonic load injecting its maximum allocated currents to the network. Harmonic current, and/or voltage, allocations to all loads were captured and compared across all scenarios. Minimum and maximum harmonic current allocations, from all network scenarios, were obtained for each load and presented as a single harmonic current source at each bus, as shown in Table 4.6 and Table 4.7. The differences between maximum and minimum values of the total allocated harmonic currents at each bus are recorded in Table 4.8. Results have shown that harmonic allocations can change significantly from one network scenario to another – anywhere from 24% to 97%. It is shown that depending on the network scenario chosen for harmonic allocation, harmonic absorption and impedance attenuation capabilities of the network can be drastically under-utilised. This raises a question as to what are the recommended tools and processes that can be adopted to perform harmonic allocations for transmission systems with a very large number of network scenarios, e.g. a few thousand network scenarios.

Table 4.6 – Minimum Harmonic Current Allocation to Loads from 22 Network Scenarios

Harmonic Order	Bus 1 (pu)	Bus 2 (pu)	Bus 5 (pu)	Bus 6 (pu)	Bus 7 (pu)
	Load 11 & Load 12	Load 2	Load 5	Load 6	SVC
2	0.0508	0.0117	0.0089	0.0226	0.0027
3	0.0312	0.0050	0.0012	0.0119	0.1161
4	0.0212	0.0046	0.0073	0.0160	0.0017
5	0.0538	0.0140	0.0125	0.0379	0.0355
6	0.0093	0.0019	0.0014	0.0050	0.0005
7	0.0398	0.0065	0.0040	0.0176	0.0022
8	0.0064	0.0009	0.0006	0.0040	0.0003
9	0.0093	0.0011	0.0010	0.0097	0.0089
10	0.0027	0.0002	0.0004	0.0038	0.0007
11	0.0263	0.0024	0.0026	0.0134	0.0082
12	0.0052	0.0006	0.0005	0.0040	0.0005
13	0.0258	0.0042	0.0017	0.0155	0.0031
14	0.0017	0.0003	0.0000	0.0023	0.0000
15	0.0013	0.0003	0.0001	0.0020	0.0015
16	0.0021	0.0009	0.0005	0.0022	0.0003
17	0.0108	0.0036	0.0013	0.0063	0.0033
18	0.0022	0.0005	0.0005	0.0035	0.0004
19	0.0213	0.0044	0.0013	0.0126	0.0024
20	0.0039	0.0011	0.0002	0.0016	0.0002
21	0.0048	0.0009	0.0006	0.0028	0.0003
22	0.0055	0.0013	0.0015	0.0049	0.0001
23	0.0111	0.0027	0.0112	0.0205	0.0013
24	0.0045	0.0012	0.0020	0.0057	0.0003
25	0.0152	0.0041	0.0016	0.0183	0.0016

Table 4.7 – Maximum Harmonic Current Allocation to Loads from 22 Network Scenarios

Harmonic Order	Bus 1 (pu)	Bus 2 (pu)	Bus 5 (pu)	Bus 6 (pu)	Bus 7 (pu)
	Load 11 & Load 12	Load 2	Load 5	Load 6	SVC
2	0.1094	0.0173	0.0214	0.0306	0.0027
3	0.1077	0.0148	0.0191	0.0247	0.1161
4	0.0450	0.0060	0.2476	0.2610	0.0017
5	0.1039	0.0183	0.0485	0.0648	0.0355
6	0.0189	0.0030	0.0056	0.0088	0.0005
7	0.0892	0.0123	0.0196	0.0355	0.0022
8	0.0158	0.0019	0.0028	0.0058	0.0003
9	0.0341	0.0038	0.0051	0.0148	0.0089
10	0.0100	0.0010	0.0014	0.0063	0.0007
11	0.0419	0.0034	0.0057	0.0318	0.0082
12	0.0110	0.0013	0.0027	0.0075	0.0005
13	0.0565	0.0067	0.0124	0.0342	0.0031
14	0.0111	0.0017	0.0013	0.0050	0.0000
15	0.0107	0.0030	0.0013	0.0045	0.0015
16	0.0091	0.0039	0.0023	0.0044	0.0003
17	0.0395	0.0122	0.0084	0.0241	0.0033
18	0.0123	0.0024	0.0015	0.0060	0.0004
19	0.0448	0.0080	0.0109	0.0259	0.0024
20	0.0114	0.0017	0.0043	0.0053	0.0002
21	0.0088	0.0012	0.0042	0.0043	0.0003
22	0.0108	0.0018	0.0067	0.0072	0.0001
23	0.0383	0.0127	0.0239	0.0383	0.0013
24	0.0098	0.0094	0.0118	0.0380	0.0003
25	0.0333	0.0153	0.0259	0.0645	0.0016

Table 4.8 – Variance between Max and Min Current Allocation to Loads from 22 Network Scenarios

Harmonic Order	Bus 1	Bus 2	Bus 5	Bus 6	Bus 7
	Load 11 & Load 12	Load 2	Load 5	Load 6	SVC
2	54%	32%	58%	26%	0%
3	71%	66%	94%	52%	0%
4	53%	24%	97%	94%	0%
5	48%	24%	74%	41%	0%
6	51%	36%	75%	44%	0%
7	55%	47%	80%	50%	0%
8	60%	55%	80%	31%	0%
9	73%	70%	79%	34%	0%
10	73%	77%	70%	40%	0%
11	37%	28%	54%	58%	0%
12	52%	53%	82%	47%	0%
13	54%	38%	86%	55%	0%
14	85%	84%	96%	54%	0%
15	88%	89%	91%	55%	0%
16	77%	77%	77%	50%	0%
17	73%	71%	85%	74%	0%
18	82%	79%	68%	42%	0%
19	52%	45%	89%	51%	0%
20	66%	32%	96%	70%	0%
21	45%	28%	85%	34%	0%
22	49%	29%	78%	32%	0%
23	71%	79%	53%	46%	0%
24	53%	87%	83%	85%	0%
25	54%	73%	94%	72%	0%

Key: ● Variance ≥ 65 %; ● 43 % ≤ Variance < 65% MVA; ● Variance < 43% MVA

4.5 Summary

Case studies conducted in this chapter have demonstrated that harmonic impedances can change significantly under different network scenarios and hence affecting the effectiveness of harmonic allocations to loads. A methodical research method, which was based on a systems engineering approach, has been employed to investigate the effects of different combinations and types of network elements on harmonic impedances. In this method, characteristics of harmonic impedances of individual network elements were examined. These elements were subsequently combined in stages to partially reconstruct the network from different types of network elements. Finally, the complete 7-bus network, including all elements, was studied under N-1 contingencies – 22 scenarios were considered.

It was found that the short circuit power, which is directly related to network self-impedance at a fundamental frequency, has a direct impact on network fundamental frequency voltages but no correlation to harmonic impedances and allocations. Although network self-impedances may appear inductive at a fundamental frequency, they do not change linearly with harmonic frequencies.

It was observed that long transmission lines are the key contributors to multiple sharp harmonic impedances, mainly due to resonance circuits formed between its shunt capacitance and series inductance. The shunt capacitor bank is another type of network element that contributes strongly to the parallel and series resonances in transmission systems. In contrast, inductive network elements such as power transformer, synchronous generators, motors and aggregated loads provide good attenuation effects to resonant impedances. In particular, synchronous generators and energy consumption loads can significantly attenuate harmonic resonant impedances and mitigate sharp resonance conditions in transmission networks.

It can be concluded that transmission network harmonic impedances are complex and their characteristics, which are highly dependent on different network scenarios (i.e. different mix of network elements) at different harmonic frequencies, cannot be precisely predicted based on simulations alone. They should be compared with actual experimental measurements, which are outside the scope of this thesis. However, the overall trend of harmonic impedances can still be estimated based on a different combination of network elements in an electrical network area.

Although not common, the worst *Influence Coefficient* (maximum $K_{j,i}(h)$ - remote amplification) would occur when the parallel resonance of mutual impedance (highest $Z_{i,j}(h)$) coincides with the series resonance of self-impedance (lowest $Z_{j,j}(h)$). Generally, remote amplification occurs when self-impedance at a PCC is lower than mutual impedance between that PCC and remote buses because the *Influence Coefficient* is greater than one, i.e. $Z_{i,j}(h)$) / $Z_{j,j}(h)$ >1. In particular, a harmonic source is connected to a low self-impedance bus (e.g. high *SCP* bus) can cause very high remote amplifications to remote buses that have high mutual impedance relative to the loaded bus.

The effect of changes of harmonic impedances, under different network scenarios, on harmonic allocation cannot be underestimated. It was found that, out of 22 network scenarios, harmonic allocation to loads could vary from 24% to 97% depending on the network scenarios chosen for harmonic allocations. This emphasises the need to include all network scenarios in harmonic allocation methodology for transmission systems. This raises an important question as to how many, and which, network scenarios should be selected for harmonic allocation, given that a typical transmission system can have up to a few thousands of network scenarios. The findings from this chapter will be used to help to define practical recommendations for harmonic allocations. These recommendations will be incorporated in the "Strategic Planning Framework and Procedures for Harmonic Allocations and Assessments in Transmission Systems" in Chapter 8.

5 Recommended Amendments to IEC/TR 61000-3-6

5.1 Introduction

Chapter 4 demonstrated that the harmonic impedance of transmission systems is complex and highly dependent on network scenarios (of which there are typically many). Harmonic allocation methodologies for transmission systems that are dependent on harmonic impedance must take into account this complexity and be able to deal with large numbers of network scenarios. The IEC allocation method takes impedances into account for emission allocations, and includes determination of *influence coefficients*, which are used to find the *maximum allowable global contributions* at PCCs, and thus will be sensitive to impedance complexities.

While Chapter 2 has indicated the IEC allocation method would be considered most suitable for transmission systems, Chapter 3 identified a number of deficiencies associated with its application. These include: (i) under-allocation and over-allocation due to the high level of its dependency on load forecast and prediction of future network scenarios; (ii) the method for sharing planning levels between HV-EHV buses fails to take into account the *spare supply capacity* at the PCC, hence the full network absorption capability is not utilised effectively; (iii) the method to assess (S_t) as the *total future load* versus (S_{tm}) as the *total supply capacity* at bus *m* is ambiguous – no clear distinction between them; and (iv) the method for determining individual limits, as the present expression suggests, does not take into account of harmonic allocation (previously allocated) and MVA sizes of existing loads – both would have material impacts on harmonic allocations. It was demonstrated that mere application of the IEC report would not always be practical for loads in a realistic transmission network with a large number of network scenarios.

The primary focus of this chapter is to propose relevant amendments to the existing IEC report to overcome the above deficiencies. The research methodology employed in this chapter includes: (i) a single scenario of the previously described 7-bus network was chosen as a base case for a harmonic allocation study; (ii) an in-depth analysis on both the existing IEC methodology and several proposed amendments to overcome existing deficiencies has been undertaken; (iii) harmonic allocation was then completed, with relevant step-by-step procedures, for loads at three buses (Bus 1, 2 and 5) following guidelines of the IEC's methodology – without and with the proposed improvements; and (iv) the allocations are then compared.

5.2 Proposed Amendments

5.2.1 Background and Principles

The existing IEC's method is dependent on knowledge of the *total power* (S_t) of all installations, i.e. total MVA power of all loads – including future loads, at a bus. It heavily relies on the accuracy of load forecasts and future network scenarios, including future network reconfigurations and augmentations. Thus, the method would only work effectively if both factors can be satisfied: (i) load forecast and prediction of future network scenarios are accurate, which is highly unlikely in practice; and (ii) *total loads* must exactly match *total supply capacities* at every busbar. The likelihood for both of these dependency factors to be met or predicted correctly is considered extremely low in practice, if not impossible. These are the major contributing factors to the deficiencies of the existing methodology in practical application.

Chapter 3 identified that the interdependent relationship between the total connecting loads and the *total supply capacity*, which includes harmonic absorption capability, is very important in harmonic management. Chapter 4 has demonstrated that both energy consumption loads and synchronous generating machines have attenuation effects on network harmonic impedances. Thus both loads and supply capacities play key roles in harmonic management. However, future supply capacities and future loads are directly influenced by economic forecast and future consumer load demands. These are unpredictable external influences that network utilities cannot control but need to accommodate for and adapt to accordingly. The harmonic allocation should be based on realistic network scenarios with a high degree of certainty, e.g. network scenarios that are included in the Transmission System Operator's (TSO's) Strategic Asset Management Plan (SAMP), which covers existing and new (proposed) loads, and corresponding available network supply capacities of all buses.

Once future loads and future supply capacities are removed from harmonic allocation procedures for present loads, the only remaining variable that can affect the balance between loads and supply capacity is the present network reconfigurations during operation and maintenance, which are under full control of the TSO. A fundamental assumption is that future loads will be subjected to network supply capacity at the time of connection. Only network augmentation that is included in the SAMP should be considered to address any shortfall of network supply capacity.

Based on the above, several amendments to the existing IEC report method are proposed to improve its practicality and effectiveness. The proposed changes are centred around the relationship between *total (present) load* and *total supply capacity* at PCCs, both of which can be accurately determined and planned for any given network scenarios in the SAMP. The aim is to maximise the *global harmonic contribution* ($G_m(h)$) at connection points that lead to the highest possible individual limits for loads while ensuring that planning levels will not be exceeded as per the current mandate of [10]. Based on the findings from Chapter 4, it can be said that fairness and equitability can only be practically achieved for loads that are installed at the same time, under the same network scenario. Allocations that were previously allocated to loads in the past under different network scenarios will be considered as background harmonic current sources injecting, their full emission right, into the present network scenario.

5.2.2 Assessing Total Load (S_t) and Total Supply Capacity

As discussed in Chapter 3, in a conventional power system the main source of supply is from synchronous generators, which are the source of *total supply capacity* and have the ability to attenuate harmonic impedances and provide low impedance paths for harmonic currents. It is suggested that the *total supply capacity*, hereafter referred to as (S_{tS}) at a bus, should provide the basis for sharing emission allocations. S_{tS} must be sufficient to accommodate all loads connected to that bus plus *spare supply capacity* required for system stability. The relationship between the *total supply capacity*, *total load* and *spare supply capacity* at a bus expressed in equation (3.28) is re-arranged below as (5.1) for clarity:

$$S_{tSm} = \sum_{a=1}^{n} S_{Loads\_ma} + S_{Spare\_m} \tag{5.1}$$

where

S_{tSm}: *Total Supply Capacity* at substation *m* at the time of assessment,

S_{Spare_m}: *Total Spare Capacity* at substation *m* at the time of assessment,

S_{Loads_ma}: *Total Load* ($Load_1$,…, $Load_a$,…, $Load_n$) to be connected, consists of existing and new loads being considered for connection, to bus *m* at the time of assessment,

Practical application of equation (5.1) to calculate the *total supply capacity*, s*pare capacity* and *total loads* (Load 11 and Load 12) connected to bus 1 of Figure 5.1 is shown in Table 5.1 below.

S*pare supply capacity* is the additional harmonic absorption capability that could be utilised to allow higher harmonic emissions from loads. Specifically, the *global contribution* at bus *m* (G_{hBm}) depends on the *total supply capacity* that caters for the *total (present) loads* and remaining *spare supply capacities*. Therefore, having a clear guideline and structured methodology to assess S_{tS} at each connection point in the network is important. In general, S_{tS} of a bus must adequately accommodate all loads connected to that bus under the lowest applicable contingency limit, which, depending on different jurisdictions, may include: thermal limit; steady-state-stability limit; transient stability limit; and electrical damping limit; and (*N*-1), (*N*-1-1), (*N*-2), and (*N*-1-50 MW) redundancy, where:

- (*N*-1): Network must be planned to supply loads at all time with one network element out of service;
- *(N-1-1)*: Network must be planned to supply full load under (*N*-1) condition and allow a forced outage of another network element while in (*N*-1) condition. The forced outage element must be restored as soon as possible or loads must be shed to maintain network stability;
- *(N-2)*: Network is planned to supply the full load with two network elements out of service under planned outage;
- *(N-1-50MW)*: A new planning criteria that allow the network to operate with one network element out of service and up to 50 MW of load can be shed.

It is proposed that the method for assessing *(S_{tS})* as the *total supply capacity* at a bus is proposed as follows (further details will be discussed in the proposed harmonic management framework in Chapter 8):

- Assessment of S_{tS} must ensure that any changes to S_{tS} in the future due to changes of network scenarios, e.g. network reconfigurations and network augmentations, will not cause any adverse effects to existing network participants. In practical terms, it means that once S_{tS} is planned for a bus, network planners must ensure that all existing network participants are not negatively impacted by any future scenarios.

- S_{tS} should be interpreted as the apparent power (MVA) "signed sum" of the *imported (incoming) power and export (outgoing) power* at a bus, satisfying all applicable contingency limits – the former must be at least equal to or higher than the latter.

- Network elements connected to a bus should be simplified and categorised into two groups:

(i) Group 1: *Importing/Incoming* power to a bus from other buses or substations via transmission lines, transformers, generators (including renewables and batteries) or HVDC;

(ii) Group 2: *Exporting/Outgoing* power from a bus to other buses or substations via transmission lines, transformers and all types of loads directly connected to that bus. The type of loads includes distribution loads at bulk supply points, metal refineries, rail electrification, mining, and power-electronic controlled loads, such as HVDC, SVC, STATCOM, Voltage Source Converters (VSCs) and other non-linear loads.

- Similar to a transmission line, an HVDC line transfers power from one substation to another, therefore, depending on the direction of power flow it could be counted either as an incoming (importing) or an outgoing (exporting) power supply at a bus accordingly. Network planners have to make the decision based on their network needs.

- Power-electronic based generators, e.g. wind, solar plant and HVDC should be considered both as a power generation source and a harmonic source, e.g. harmonic current source. These plants also have small station loads and losses, which should be treated as energy consumption loads, can often be up to 5% of their total capacity.

The proposed clarification of the assessment of the supply capacity at bus *m* (S_{tSm}) is mathematically expressed below:

$$S_{tSm} = \left[\sum_{i=1}^{n} S_{Gen\_i} + \sum_{x=1}^{n} S_{Import\_Power\_x}\right] - \left[\sum_{j=1}^{n} S_{Existing\_Loads\_j} + \sum_{y=1}^{n} S_{Export\_Power\_y}\right] \qquad (5.2)$$

S_{tSm}: *Total Supply Capacity* at substation *m* at the time of assessment;
S_{Gen_i}: Connected Generation Power *I*;
$S_{Existing\_Loads\_j}$: Connected existing load *j*;
$S_{Import\_Power\_x}$: Connected Import Power *x*;
$S_{Export\_Power\_y}$: Connected Export Power *y*.

Equation (5.2) can be used to find the existing *total supply capacity* at a bus bar, which is considered as the available supply capacity for new/future loads. It is noted that existing loads, which were previously connected to the bus, are subtracted from the existing supply capacity of the bus.

Practical application of equation (5.2) to calculate the *total supply capacity*, s*pare capacity* and *total loads* at all busbars of Figure 5.1 is shown in Table 5.1 below. The *Total Supply Capacity* (S_{tSm}) at substation *m* consists of:

- *Spare Supply Capacity* to accommodate new load(s) proposed for connection at bus *m*;

- *Unused Spare Supply Capacity* that can be used to share between HV-EHV substations; and

- *Minimum Reserved Spare Capacity* for a safety margin.

Once the existing total supply capacity at a bus is calculated from (5.2), it can be used to supply new loads, including *spare supply capacity* reserved for safety margin and future loads as shown in Equation (5.3).

The relationship between the *total supply capacity*, the *total load* and *spare supply capacity* at a bus expressed in equation (5.1) and repeated here with further clarification on the make-up of s*pare supply capacity, i.e. Reserve Capacity* for future loads and safety margin*,* and *Unused Spare Capacity*.

$$S_{tSm} = \sum_{a=1}^{n} S_{Load\_ma} + S_{mR} + S_{mFL} + S_{mS} \qquad (5.3)$$

S_{Load_ma}: *Total New Load a* connected to bus *m* at the time of assessment;

S_{mR}: *Spare Supply Capacity Reserved* for safety margin;

S_{mFL}: *Spare Supply Capacity Reserved* for future loads;

S_{mS}: *Unused Spare Supply Capacity* that is planned for sharing to allow higher harmonic emissions among buses.

In the event that existing supply capacity at a bus is not sufficient to supply the new load, network augmentation will be required and the associated cost should be factored in the pricing of the new Connection and Access Agreement (C&AA) between the transmission network service provider and the prospective proponents.

Although not recommended, in theory, the *minimum reserved capacity* at every bus can be set as low as zero (0) to achieve maximum *global contribution* at all buses in the network. In practice, the *minimum reserved capacity* at each bus is recommended to be set at *p(%)*, i.e. between 10% - 25% of the *total spare capacity,* of the sum of the *reserved spare capacities* (for future loads and safety margin) and the *unused spare capacity* for sharing, based on:

$$S_{mS} = (1 - p(\%)) \times \left(S_{tSm} - \sum_{a=1}^{n} S_{Load\_ma}\right); \qquad (5.4)$$

$$S_{mR} = \left(\frac{p(\%)}{1-p(\%)}\right) \times S_{mS}; \qquad (5.5)$$

p (%): *minimum reserved capacity* expressed in percentage of *total spare capacity* at each bus.

For example, a load of 25 MVA is proposed to be connected at substation *m*, which has the *total supply capacity* of 35 MVA and *reserved capacity p (%) = 15%.*

S_{tSm}= 35 MVA

S_{Load_ma} = 25 MVA

S_{mS} = (1 – 0.15) × (35 – 25) = 8.5 MVA

S_{mR} = (0.15 / (1 – 0.15)) × 8.5 = 1.5 MVA

Therefore, 8.5 MVA of *unused spare supply capacity* can be used to share among other buses in the network to increase harmonic allocations. Sharing of the *unused spare supply capacity* will be incorporated in the proposed amendment of IEC's method for "Sharing Planning Levels Between Buses in Meshed HV-EHV Systems" below.

5.2.3 Sharing Planning Levels Between Buses in Meshed HV-EHV Systems

The methodology for sharing planning levels between buses in meshed HV-EHV systems is defined by Equation 14 of the IEC technical report [10], further expanded in Appendix D of the same document, is repeated here with proposed modification to the *total supply capacity* terminology, i.e. (S_{tm}) to be renamed as (S_{tSm}), as shown equation (5.6). The *global contribution* of harmonic emission at bus m is defined as:

$$G_m(h) \le \sqrt[\alpha]{\frac{S_{tSm}}{(K_{1-m}^{\alpha}(h)\times S_{tS1})+(K_{2-m}^{\alpha}(h)\times S_{tS2})+..+(K_{n-m}^{\alpha}(h)\times S_{tSn})}} \times L_{HV-EHV}(h) \tag{5.6}$$

The same condition, as per equation (5.6), needs to be satisfied for all buses to ensure that planning levels are not exceeded. For a system of n buses, the maximum allowed *global harmonic contribution* at bus m, (G_{hBm}), is the lowest value from n cases of (G_{hBm}) as described in Chapter 3. Therefore, to maximise harmonic allocation to loads connected to bus m, the minimum values of (G_{hBm}), from n cases, need to be maximised under all n cases. Variables associated with equation (5.6), which can be regulated to increase the *global harmonic contribution* at a bus and harmonic allocation to its loads, are analysed as follows:

(i) $L_{HV\text{-}EHV}(h)$*:* The planning voltage level for the HV and EHV system is recommended in Table 2 of the IEC report. All case studies used in this thesis have been based on the IEC's recommended planning levels for HV and EHV systems.

(ii) *Alpha (α):* Constants applied to a specific range of harmonic orders as per the IEC method. Changing alpha *(α)* to achieve higher allowable *global contribution* may be possible, but would require extensive research and field measurements to verify, hence is not in the scope of this project.

(iii) $K_{i-m}(h) = V_{i-m}(h) = \left|\frac{Z_{(m,\ i)}(h)}{Z_{(i,\ i)}(h)}\right|$: Absolute *Influence coefficient* measured or calculated at node m when 1 p.u. voltage is applied at node i. *Influence coefficients* depend on network harmonic impedances, which are fixed for each network scenario. Changes of *influence coefficients*, due to variation of harmonic impedances, are only applicable under different network scenarios as described in Chapter 4. The optimisation of *influence coefficients*, which could be achieved from different network scenarios, to allow higher g*lobal harmonic contribution* at a bus will be explored in Chapter 8.

(iv) S_{tSi}, S_{tSm}: *Total Supply Capacity*, at node i or bus m respectively, consists of the s*upply capacity* for *new loads* as well as *unused spare capacity*. This represents network harmonic absorption capability that can be utilised to increase harmonic allocation to loads. In order to utilise the shared planning level method more effectively, the *unused spare capacity* of a bus is proposed to be incorporated in the s*hare planning level* equation (5.6). Equation (5.6) is proposed to be amended to include the *unused spare capacity* as shown in equation (5.7) below. Noting (S_{mS}) is the *unused spare capacity* at bus m that can be planned, adjusted and shared (as the *spare* c*apacity to share*) with other buses. As a result, the *global contributions* at buses in the system can be increased and the level of improvements depends on the location of connection points and applicable *influence coefficients* under each network scenarios.

For n bus system, the maximum allowable *Global Contribution* from bus m is proposed as follows:

$$G_m(h) \leq \sqrt[\alpha]{\frac{S_{tSm}}{K_{1-m}^{\alpha}(h)\times(S_{tS1}-S_{1S})+K_{2-m}^{\alpha}(h)\times(S_{tS2}-S_{2S})+..+K_{n-m}^{\alpha}(h)\times(S_{tSn}-S_{nS})}} \times L_{HV-EHV}(h) \tag{5.7}$$

S_{tSm}: *Total Supply Capacity* at bus m (any arbitrary bus of the n bus system);

S_{tS1}, S_{tS2},..,S_{tSn}: Total Spare Supply Capacity at Bus 1, Bus 2, …, Bus n;

S_{1S}, S_{2S},.., S_{nS}: Planned *Unused Spare Capacity* for Sharing at Bus *1*, Bus *2*, …, Bus n.

To ensure that planning levels will not be exceeded, the *global contribution* (G_{hBm}) at bus m in a system of <u>n buses</u> must satisfy all <u>n conditions</u> below - example provided for Bus 1:

***Global contribution* at Bus 1:**

Condition 1:

$$G_{B1}(h) \leq \sqrt[\alpha]{\frac{S_{tS1}}{K_{1-1}^{\alpha}(h)\times(S_{tS1}-S_{1S})+K_{2-1}^{\alpha}(h)\times(S_{tS2}-S_{2S})+..+K_{n-1}^{\alpha}(h)\times(S_{tSn}-S_{nS})}} \times L_{HV-EHV}(h) \tag{5.8}$$

Condition 2:

$$G_{B1}(h) \leq \sqrt[\alpha]{\frac{S_{tS1}}{K_{1-2}^{\alpha}(h)\times(S_{tS1}-S_{1S})+K_{2-2}^{\alpha}(h)\times(S_{tS2}-S_{2S})+..+K_{n-2}^{\alpha}(h)\times(S_{tSn}-S_{nS})}} \times L_{HV-EHV}(h) \tag{5.9}$$

Condition n:

$$G_{B1}(h) \leq \sqrt[\alpha]{\frac{S_{tS1}}{K_{1-n}^{\alpha}(h)\times(S_{tS1}-S_{1S})+K_{2-n}^{\alpha}(h)\times(S_{tS2}-S_{2S})+..+K_{n-n}^{\alpha}(h)\times(S_{tSn}-S_{nS})}} \times L_{HV-EHV}(h) \tag{5.10}$$

Noting that: $K_{1-1}(h) = K_{2-2}(h) = \ldots = K_{n-n}(h) = 1$

The main intention is to utilise the *spare supply capacity* available at relevant busbars (e.g. S_{1S}, S_{2S},..,S_{nS}) to increase the *maximum allowable global contribution* of the connection point (e.g. $G_{B1}(h)$). Therefore, only the term (S_{iS}) needs to be subtracted from the *total supply capacity* of each busbar (S_{tS1}, S_{tS2},.., S_{tSn}) in the denominator. The *total supply capacity* (e.g. S_{tS1}) in the nominator represents the maximum capacity of the PCC, including *spare capacity*, which deserves allocation to be proportional to its maximum capacity.

5.2.4 Method for Determining Individual Limits

The method for determining individual limits, expressed by equation (15) and (16) in Section 9.2.3 of [10], is repeated as equations (5.11) and (5.12). The former does not adequately account for harmonic emission of the existing loads connected to the same bus because it does not include voltage emission, e.g. $E_{Uh\_Existing\_Loads}$, from existing loads. Therefore, its application can result in over-allocation and harmonic voltages exceed planning levels due to unaccounted background harmonic voltages.

According to the existing IEC method, harmonic voltage and current allocations for load S_i connected to bus m are shown as (5.11) and (5.12) respectively:

Harmonic voltage allocation for load S_i connected to bus m is:

$$E_{Uih} = G_{hBm} \sqrt[\alpha]{\frac{S_i}{S_{tm}}} \tag{5.11}$$

The equivalent harmonic current allocation to that distorting load can be defined using:

$$E_{Ihi} = \frac{E_{Uhi}}{Z_{hi}} \tag{5.12}$$

Where according to the IEC report:

- E_{Uhi}: Is the emission limit of non-linear installation i at harmonic order h;
- G_{hBm}: Is the *maximum global contribution* to the h^{th} harmonic voltage of all distorting installations connected to substation *Bm;*
- S_i: Is the MVA rating of the distorting installation;
- S_{tm}: Is total supply capacity of substation *m.*

The term S_t in equation (3.21), repeated from equation (10) in Section 9.2.1 of the IEC report, was referred to as an approximation of the total power of all present and future loads. However, the same terminology was expressed by equation (5.11) above as the *total supply capacity* at bus m (as amended from S_{tm} *to* S_{tSm} is shown in (5.7) above). It appears that the IEC report assumed that the *total supply capacity* at a bus would always be the same as the *total load*, including all future loads, hence used these terminologies interchangeably. This assumption is not practical as the total supply capacity at a bus must always be greater than the total load connected to that bus for the power system to function. Therefore, *total load* and *total supply capacity* at a PCC should be distinguished. The inconsistent use of terminologies among different expressions can cause misinterpretation and result in unintended outcomes. It is recommended that the expression for individual emission limits (5.11) be amended as follows:

$$E_{U\,i}(h) = \sqrt[\alpha]{\left(G_m^{\alpha}(h) - \sum_j^n E_{U\_ExistingLoads\_j@m}^{\alpha}(h)\right)\left(\frac{S_i}{S_{tSm} - \sum_j^n S_{ExistingLoads\_j@m}}\right)} \tag{5.13}$$

New equation (5.13) is proposed to supersede (5.11) above, which is currently used by the IEC report. Noting $E_{U\_ExistingLoads\_j@m}(h)$ is the emission limit of the existing loads connected to bus m, and $S_{Existing\_Loadsj@m}$ is the agreed power (or MVA rating) of existing loads. The *total supply capacity* (S_{tSm}) also includes *reserved spare capacit*y and *unused spare capacity*, as expressed in equation (5.3), available for sharing with other buses.

Equation (5.13) now takes into account the total voltage emission from all existing loads, i.e. $\sum_j^n E_{U\_ExistingLoads\_j@m}^{\alpha}(h)$, connected to the PCC, and their total power, $\sum_j^n S_{ExistingLoads\_j@m}$. It means that the voltage allocation for load i, power S_i, connected to bus m that already has some pre-existing loads j share the maximum global contribution $G_m(h)$ (less the existing load emission); and proportional to its power S_i, relative to total supply capacity S_{tSm} at bus m (less the sum of existing load power).

5.3 Allocation Case Study – Without and With Proposed Amendments

A case study has been conducted to allocate harmonic emissions to loads of a simplified 7-bus transmission system presented in Figure 3.1 (Chapter 3) and modified as shown in Figure 5.1 below. Parameters of this network were provided in Table 3.1 – 3.5 in Chapter 3.

This case study focused on the application of the proposed amendments to the existing IEC method to overcome its deficiencies. Assumptions used in this case study have been based on a typical Australian transmission system and relevant rules and regulatory frameworks. It demonstrates how the global contribution (G_{hBm}) at connection points and the individual limits (E_{Uhi}) for loads can be practically improved by sharing the *unused spared capacities* in the network.

Harmonic allocation was undertaken for all loads shown in Figure 5.1 without and with the proposed amendments. The main aim was to demonstrate utilisation of the *unused spare supply capacities* to achieve maximum allowable *global harmonic contributions* at all buses. The following assumptions were applied to the case study network of Figure 5.1:

- Transmission lines Line 8, Line 9 and Line 10 are out of service (OOS);
- Capacitors Cap 5 and Cap 6 are out of service;
- Load 6 is an unknown future load, which would require network augmentation, and has been excluded from the allocation due to its uncertainty;
- SVC is an existing harmonic current source that was previously allocated and takes up its full allocation;
- All loads – Load 11, Load 12, Load 2 and Load 5 – will be allocated at the same time to simplify allocation procedures and minimise the efforts required. The impact of staged connections, i.e. different loads being connected at different times under different network scenarios, are considered later in the thesis (Chapter 8).

The network shown in Figure 5.1 is just one sample network scenario chosen for this case study. There are many possible scenarios, and it is acknowledged that different network scenarios can lead to different allocation results. However, the purpose of this case study is to demonstrate the relative improvements between the IEC methodologies – without and with proposed amendments above – under the same network scenario. This case study will demonstrate the procedural assessment of the *total supply capacity*, including reserved spare capacities for safety margins and future loads, as well as the unused capacity to share, and harmonic allocation to loads.

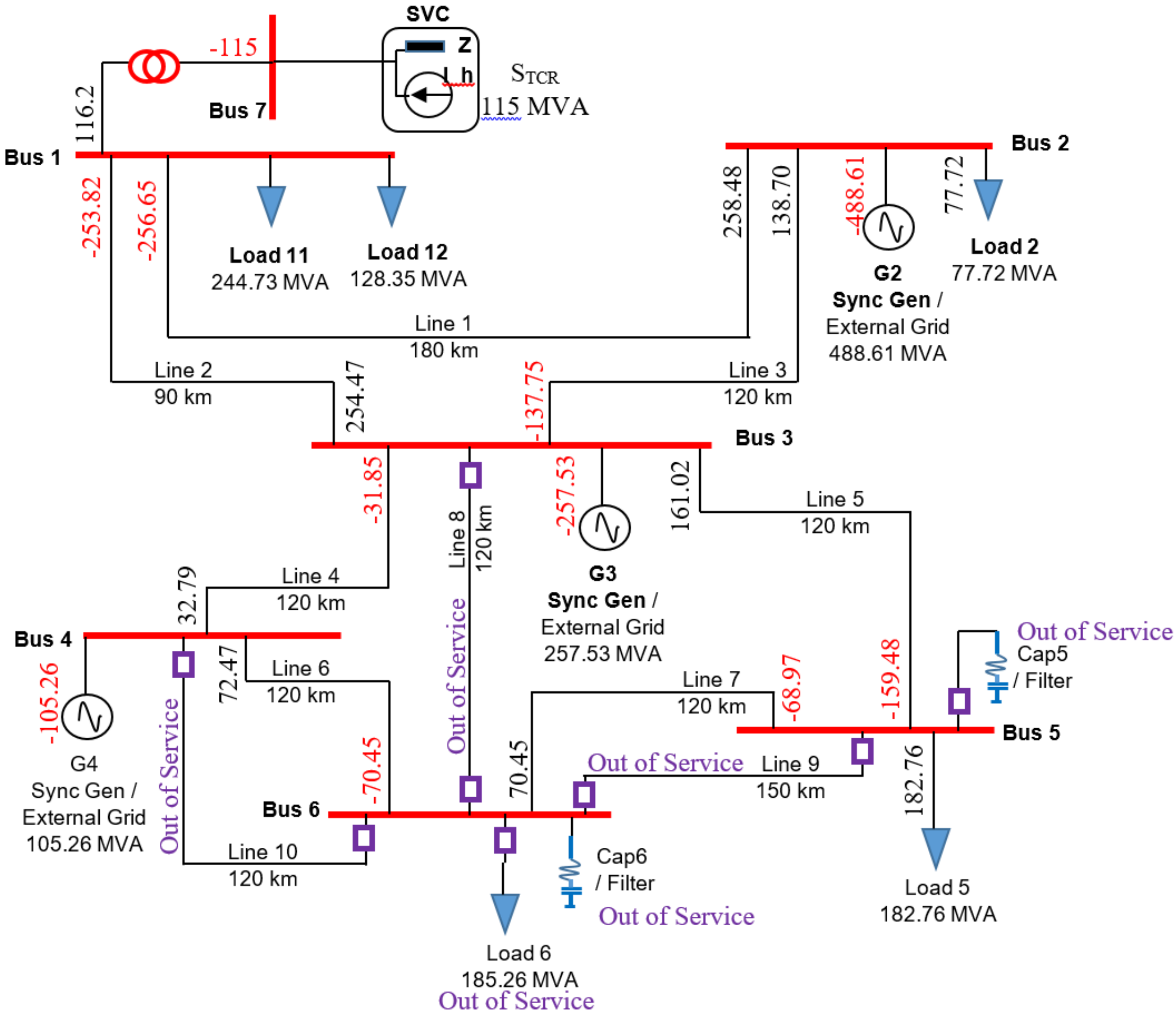


Figure 5.1 – Harmonic Allocation Case Study 7-Bus 132kV Transmission Network

5.3.1 Assessment of the *Total Supply Capacity* (S_{tS}) and Loads

Equations (5.1), (5.2) and (5.3) have been applied to calculate supply capacities at all buses and results are summarised in Table 5.1. An example calculation is provided below for Bus 1 (only) to demonstrate the process applied.

Application of equation (5.2) to calculate: ***Total Supply Capacity at Bus 1***

$$S_{tSm} = \left[\sum_{i=1}^{n} S_{Gen\_i} + \sum_{x=1}^{n} S_{Import\_Power\_x}\right] - \left[\sum_{j=1}^{n} S_{Existing\_Loads\_j} + \sum_{y=1}^{n} S_{Export\_Power\_y}\right];$$

$$\begin{aligned} S_{tS1} &= [0 + (256.65 + 253.82)] - [116 + 0] \\ &= 394.27\ MVA; \end{aligned}$$

Application of equation (5.1) to calculate: ***Total Spare Capacity at Bus 1***

Based on equation (5.1) and (5.3);

$$\left.\begin{aligned} S_{tSm} &= \sum_{a=1}^{n} S_{Loads_{ma}} + S_{Spare_m} \\ S_{tSm} &= \sum_{a=1}^{n} S_{Load\_a} + S_{mR} + S_{mFL} + S_{mS} \end{aligned}\right\} \xrightarrow{yields}$$

$$S_{Spare\_m} = S_{tSm} - \sum_{a=1}^{n} S_{Loads\_a}$$

$$= 394.27 - (244.73 + 128.35)$$

$$= 21.19\ MVA;$$

$$S_{Spare\_m} = S_{mR} + S_{mFL} + S_{mS}$$

$$= 21.19\ MVA;$$

Loads connected to transmission systems in Australia are often greater than 30 MVA [19], hence it is highly unlikely that 21.19 MVA will be sufficient for any future transmission load to be connected at Bus 1. The current asset management (network development) plan assumes that any future load to be connected at Bus 1 would require network augmentation to increase the *supply capacity* accordingly. The *reserved spare capacity* for safety margin is set at *p = 10%* of the *Total Spare Capacity*. Therefore, application of equations (5.1), (5.2) and (5.3) yields:

Spare Capacity Reserved for Future Load $S_{mFL} = 0$;

Spare Capacity Reserved for Safety Margin $S_{mR} = 10\% \times S_{Spare\_m}$

$= 0.1 \times 21.19$

$= 2.12$ MVA;

Unused Spare Capacity for Sharing $S_{mS} = S_{Spare\_m} - (S_{mR} + S_{mFL})$

$= 21.19 - 2.12$

$= 19.07\ MVA.$

Table 5.1 – Case Study – Demonstration of Total Supply Capacity, Spare Capacity and Loads

Network Elements	Loss (MVA)	Bus 1 (MVA)	Bus 2 (MVA)	Bus 3 (MVA)	Bus 4 (MVA)	Bus 5 (MVA)	Bus 6 (MVA)	Bus 7 (MVA)
Line 1 [Bus 1 – 2]	1.83	-256.65	258.48					
Line 2 [Bus 1 – 3]	0.65	-253.82		254.47				
Line 3 [Bus 2 – 3]	0.95		138.7	-137.75				
Line 4 [Bus 3 – 4]	0.94			-31.85	32.79			
Line 5 [Bus 3 – 5]	1.54			161.02		-159.48		
Line 6 [Bus 4 – 6]	2.02				72.47		-70.45	
Line 7 [Bus 3 – 5]	1.48					-68.97	70.45	
T1 Transformer	1.2	116.2						-115
Gen 2 (Bus 2)			-488.61					
Gen 3 (Bus 3)				-257.53				
Gen 4 (Bus 4)					-105.26			
Total Supply Capacity		**-394.27**	**-91.43**	**-11.64**	**0**	**-228.45**	**0**	**-115**
Load 2 (@ Bus2)			77.72					
Load 5 (@ Bus 5)					182.76			
Load 11 (Bus 1)		244.73						
Load 12 (Bus 1)		128.35						
Existing SVC								115
Total Load		**373.08**	**77.72**	**0.00**	**0.00**	**182.76**	**0.00**	**115**
Total Spare Supply Capacity		**21.19**	**13.71**	**11.64**	**0.00**	**45.69**	**0.00**	**0.00**
Reserved Capacity for Future Load		0	0	0	0	0	0	0
Reserved Capacity x (%)		10%	10%	10%		10%		0%
S_{mS} *(Shared Capacity)*		19.07	12.34	10.48	0.00	41.12	0.00	0.00
S_{mR} *(Reserved Capacity)*		2.12	1.37	1.16	0.00	4.57	0.00	0.00

-ve: Incoming / Importing Power

+ve: Outgoing / Exporting Power

5.3.2 Sharing of Planning Levels

Global harmonic contribution at each bus is calculated separately under two options – the IEC method without and with proposed improvements. As discussed above, for a 7-bus system, seven (7) conditions satisfying equations (5.7) - (5.10) need to be utilised to calculate the maximum allowable *global harmonic contributions* for each bus without and with recommended amendments respectively. The global harmonic contribution at loaded buses – Bus 1, Bus 2 and Bus 5 – have been plotted in Figure 5.2 below. This figure shows that there are considerable increases in allowable *global harmonic contributions* from Bus 1, 2 and 5 due to the proposed amendments applied to the IEC method.

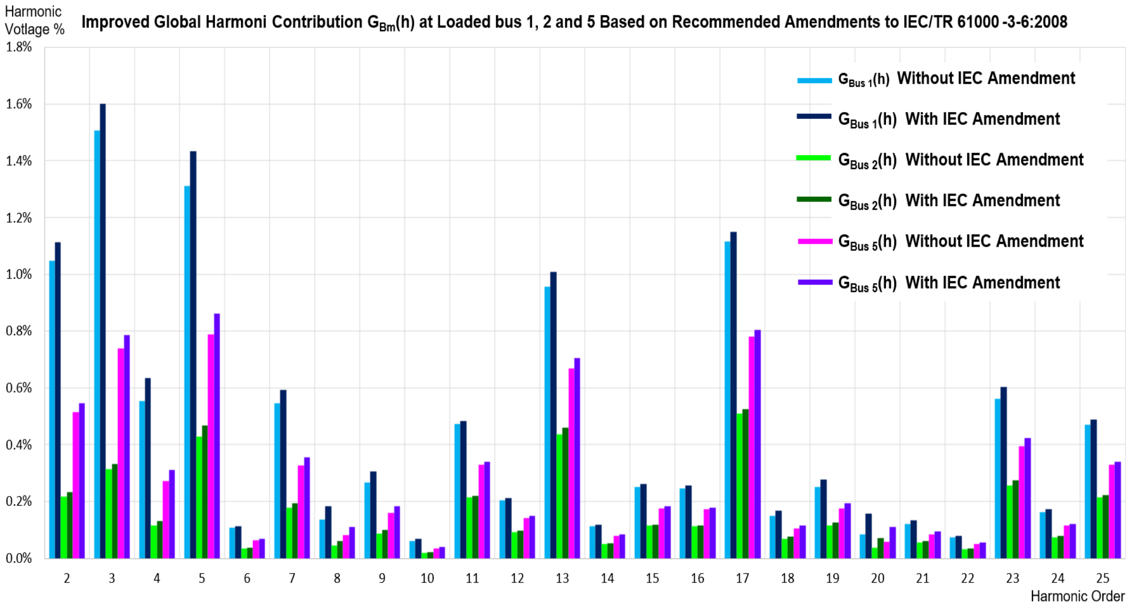


Figure 5.2 –Global Harmonic Contributions at Buses 1, 2 and 5 – Without and With Improvement.

This result shows that with the *spare capacity reserved* for safety margin is set at *p = 10%* as shown in Table 5.1, *global harmonic contributions* at loaded buses were increased accordingly, due to the recommended amendments, as shown in Table 5.2 below. The increase of harmonic allocation at Bus1, 2 and 3 varies at different frequencies, e.g. between 2.47% at the 11th harmonic and 86.35% at the 20th harmonic.

Table 5.2 – Recommended Current Allocation Based on Proposed Amendment to IEC/TR 61000-3-6 – With 10% Reserved Spare Capacity

	Minimum Allocated Currents			Recommended Allocated Currents (10% Safety Margin)			Increase (%)
h	I_{Bus1_Min}	I_{Bus2_Min}	I_{Bus5_Min}	I_{Bus1_Max}	I_{Bus2_Max}	I_{Bus5_Max}	
2	10.54%	1.42%	1.19%	11.17%	1.50%	1.26%	**5.98%**
3	10.69%	1.34%	1.03%	11.33%	1.42%	1.09%	**5.98%**
4	3.16%	0.36%	0.24%	3.62%	0.41%	0.27%	**14.62%**
5	6.43%	1.02%	0.39%	7.03%	1.12%	0.43%	**9.40%**
6	0.50%	0.07%	0.01%	0.53%	0.07%	0.01%	**5.90%**
7	2.73%	0.39%	0.09%	2.96%	0.42%	0.10%	**8.58%**
8	0.58%	0.07%	0.07%	0.79%	0.09%	0.10%	**34.84%**
9	1.11%	0.11%	0.43%	1.27%	0.13%	0.50%	**14.86%**
10	0.26%	0.02%	0.19%	0.30%	0.03%	0.22%	**14.61%**
11	3.87%	0.20%	0.53%	3.97%	0.20%	0.54%	**2.47%**
12	1.14%	0.11%	0.12%	1.19%	0.11%	0.12%	**4.41%**
13	5.35%	0.80%	0.29%	5.64%	0.84%	0.31%	**5.35%**
14	0.55%	0.16%	0.01%	0.58%	0.17%	0.01%	**5.81%**
15	1.21%	0.24%	0.02%	1.26%	0.25%	0.02%	**3.34%**
16	1.15%	0.46%	0.06%	1.19%	0.48%	0.07%	**3.40%**
17	4.99%	1.52%	0.60%	5.14%	1.57%	0.61%	**2.86%**
18	0.66%	0.14%	0.17%	0.74%	0.15%	0.19%	**11.20%**
19	1.11%	0.16%	0.72%	1.24%	0.18%	0.80%	**11.14%**
20	0.39%	0.04%	0.07%	0.72%	0.08%	0.13%	**86.35%**
21	0.49%	0.07%	0.06%	0.55%	0.08%	0.06%	**11.93%**
22	0.27%	0.23%	0.05%	0.30%	0.25%	0.05%	**7.67%**
23	2.19%	0.66%	0.50%	2.35%	0.70%	0.53%	**7.29%**
24	0.72%	0.12%	0.15%	0.76%	0.13%	0.16%	**6.09%**
25	2.56%	0.30%	0.23%	2.66%	0.31%	0.24%	**3.66%**

Notes: For allocation purpose, triplens harmonics are also included, as per the IEC method, because loads may generate triplen harmonics. This occurs even without a neutral connection when there is some unbalance, and that the triplens are not zero-sequence. It has an impact on the impedance Z_h used to convert E_{Uhi} to E_{Ihi}.

With the *spare capacity reserved* for a safety margin is set at *p = 10%.,* maximum harmonic voltages at all buses, when all loads take up their full allocations, are shown in Table 5.3, and graphically illustrated in Figure 5.3. The results show that harmonic allocation is maximised with a 10% safety margin, such that all busbar voltages are allowed to increase up to, but not exceeded, planning levels as shown.

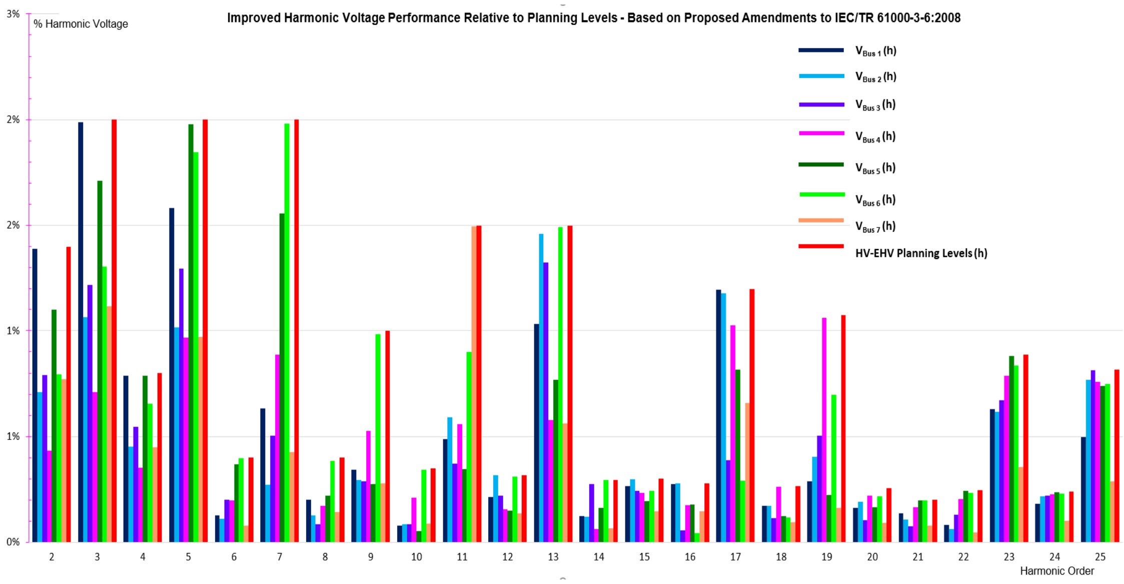


Figure 5.3 – Improved Harmonic Voltage Performance Relative To Planning Levels.

Table 5.3 – Harmonic Voltage Performance Relative to Planning Levels When Loads Take Up their Recommended Current Allocation.

Maximum Harmonic Voltage Performance Achieved Based on Proposed Amendment to IEC/TR 61000-3-6								
h	**L_{HV_EHV}**	**E_{UhBus1}**	**E_{UhBus2}**	**E_{UhBus3}**	**E_{UhBus4}**	**E_{UhBus5}**	**E_{UhBus6}**	**E_{UhBus7}**
2	**1.40%**	1.39%	0.71%	0.79%	0.43%	1.10%	0.79%	0.77%
3	**2.00%**	1.99%	1.06%	1.22%	0.71%	1.71%	1.31%	1.12%
4	**0.80%**	0.79%	0.45%	0.55%	0.35%	0.79%	0.66%	0.45%
5	**2.00%**	1.58%	1.02%	1.30%	0.97%	1.98%	1.85%	0.97%
6	**0.40%**	0.13%	0.11%	0.20%	0.20%	0.37%	0.40%	0.08%
7	**2.00%**	0.63%	0.27%	0.51%	0.89%	1.56%	1.98%	0.43%
8	**0.40%**	0.20%	0.13%	0.08%	0.17%	0.22%	0.38%	0.14%
9	**1.00%**	0.34%	0.30%	0.29%	0.53%	0.28%	0.98%	0.28%
10	**0.35%**	0.08%	0.09%	0.09%	0.21%	0.05%	0.34%	0.09%
11	**1.50%**	0.49%	0.59%	0.37%	0.56%	0.35%	0.90%	1.50%
12	**0.32%**	0.22%	0.32%	0.22%	0.16%	0.15%	0.31%	0.14%
13	**1.50%**	1.03%	1.46%	1.33%	0.58%	0.77%	1.49%	0.56%
14	**0.30%**	0.12%	0.12%	0.28%	0.06%	0.16%	0.29%	0.07%
15	**0.30%**	0.27%	0.30%	0.24%	0.23%	0.20%	0.24%	0.15%
16	**0.28%**	0.28%	0.28%	0.06%	0.18%	0.18%	0.04%	0.15%
17	**1.20%**	1.20%	1.18%	0.39%	1.03%	0.82%	0.29%	0.66%
18	**0.27%**	0.17%	0.17%	0.11%	0.26%	0.12%	0.12%	0.10%
19	**1.07%**	0.29%	0.40%	0.50%	1.06%	0.22%	0.70%	0.16%
20	**0.26%**	0.16%	0.19%	0.10%	0.22%	0.17%	0.22%	0.09%
21	**0.20%**	0.14%	0.11%	0.08%	0.17%	0.20%	0.20%	0.08%
22	**0.25%**	0.08%	0.06%	0.13%	0.21%	0.24%	0.23%	0.05%
23	**0.89%**	0.63%	0.62%	0.67%	0.79%	0.88%	0.84%	0.36%
24	**0.24%**	0.18%	0.22%	0.22%	0.23%	0.24%	0.23%	0.10%
25	**0.82%**	0.50%	0.77%	0.81%	0.76%	0.74%	0.75%	0.29%

Maximum allocations to loads have been achieved, as shown in Table 5.4 if all *reserved spare capacities* are set to zero (0), i.e. $p = 0$ %. It means that the *total available spare capacities* can be used to share among buses to maximise *global harmonic contributions* at all load buses. With zero safety margin, the increase of harmonic allocation at Bus1, 2 and 3 varies at different frequencies, e.g. between 2.75% at 11th harmonic and 114.67% at 20th harmonic. However, this is not recommended in practice because there are no margins left in the network as harmonic voltages reach planning levels at every harmonic as shown in Table 5.5 below.

Table 5.4 – Maximum Current Allocation Based on Proposed Amendment to IEC/TR 61000-3-6 – No Reserved Spare Capacity.

	Minimum Allocated Currents			Maximum Allocated Currents (Without Safety Margin)			Increase (%)
h	I_{Bus1_Min}	I_{Bus2_Min}	I_{Bus5_Min}	I_{Bus1_Max}	I_{Bus2_Max}	I_{Bus5_Max}	
2	10.54%	1.42%	1.19%	11.25%	1.51%	1.27%	**6.69%**
3	10.69%	1.34%	1.03%	11.41%	1.43%	1.10%	**6.69%**
4	3.16%	0.36%	0.24%	3.68%	0.42%	0.28%	**16.51%**
5	6.43%	1.02%	0.39%	7.11%	1.13%	0.43%	**10.58%**
6	0.50%	0.07%	0.01%	0.53%	0.07%	0.01%	**6.61%**
7	2.73%	0.39%	0.09%	2.99%	0.43%	0.10%	**9.64%**
8	0.58%	0.07%	0.07%	0.82%	0.10%	0.10%	**40.69%**
9	1.11%	0.11%	0.43%	1.29%	0.13%	0.50%	**16.85%**
10	0.26%	0.02%	0.19%	0.31%	0.03%	0.22%	**16.56%**
11	3.87%	0.20%	0.53%	3.98%	0.20%	0.54%	**2.75%**
12	1.14%	0.11%	0.12%	1.19%	0.11%	0.12%	**4.79%**
13	5.35%	0.80%	0.29%	5.67%	0.85%	0.31%	**6.00%**
14	0.55%	0.16%	0.01%	0.59%	0.17%	0.01%	**6.52%**
15	1.21%	0.24%	0.02%	1.26%	0.25%	0.02%	**3.74%**
16	1.15%	0.46%	0.06%	1.19%	0.48%	0.07%	**3.80%**
17	4.99%	1.52%	0.60%	5.15%	1.57%	0.61%	**3.20%**
18	0.66%	0.14%	0.17%	0.75%	0.15%	0.19%	**12.69%**
19	1.11%	0.16%	0.72%	1.25%	0.18%	0.81%	**12.62%**
20	0.39%	0.04%	0.07%	0.83%	0.09%	0.15%	**114.67%**
21	0.49%	0.07%	0.06%	0.55%	0.08%	0.06%	**13.53%**
22	0.27%	0.23%	0.05%	0.30%	0.25%	0.05%	**8.64%**
23	2.19%	0.66%	0.50%	2.37%	0.71%	0.54%	**8.20%**
24	0.72%	0.12%	0.15%	0.77%	0.13%	0.16%	**6.83%**
25	2.56%	0.30%	0.23%	2.67%	0.32%	0.24%	**4.09%**

Table 5.5 – Maximum Harmonic Voltage Performance Reached to Planning Levels When Loads Take Up their Maximum Current Allocation.

Maximum Harmonic Voltage Performance Achieved Based on Proposed Amendment to IEC/TR 61000-3-6								
h	L_{HV_EHV}	E_{UhBus1}	E_{UhBus2}	E_{UhBus3}	E_{UhBus4}	E_{UhBus5}	E_{UhBus6}	E_{UhBus7}
2	**1.40%**	**1.40%**	0.72%	0.80%	0.44%	1.11%	0.80%	0.78%
3	**2.00%**	**2.00%**	1.07%	1.23%	0.71%	1.72%	1.32%	1.12%
4	**0.80%**	0.80%	0.46%	0.56%	0.36%	**0.80%**	0.67%	0.46%
5	**2.00%**	1.60%	1.03%	1.31%	0.98%	**2.00%**	1.87%	0.98%
6	**0.40%**	0.13%	0.11%	0.20%	0.20%	0.37%	**0.40%**	0.08%
7	**2.00%**	0.64%	0.28%	0.51%	0.90%	1.57%	**2.00%**	0.43%
8	**0.40%**	0.21%	0.13%	0.09%	0.18%	0.23%	**0.40%**	0.15%
9	**1.00%**	0.35%	0.30%	0.30%	0.53%	0.28%	**1.00%**	0.28%
10	**0.35%**	0.08%	0.09%	0.09%	0.21%	0.05%	**0.35%**	0.09%
11	**1.50%**	0.49%	0.59%	0.37%	0.56%	0.35%	0.90%	**1.50%**
12	**0.32%**	0.22%	**0.32%**	0.22%	0.16%	0.15%	0.31%	0.14%
13	**1.50%**	1.04%	1.47%	1.33%	0.58%	0.77%	**1.50%**	0.57%
14	**0.30%**	0.13%	0.12%	0.28%	0.06%	0.16%	**0.30%**	0.07%
15	**0.30%**	0.27%	**0.30%**	0.24%	0.23%	0.20%	0.24%	0.15%
16	**0.28%**	0.28%	**0.28%**	0.06%	0.18%	0.18%	0.04%	0.15%
17	**1.20%**	**1.20%**	1.18%	0.39%	1.03%	0.82%	0.29%	0.66%
18	**0.27%**	0.17%	0.18%	0.12%	**0.27%**	0.13%	0.12%	0.10%
19	**1.07%**	0.29%	0.41%	0.51%	**1.07%**	0.23%	0.71%	0.17%
20	**0.26%**	0.19%	0.22%	0.12%	0.26%	0.19%	**0.25%**	0.11%
21	**0.20%**	0.14%	0.11%	0.08%	0.17%	0.20%	**0.20%**	0.08%
22	**0.25%**	0.08%	0.06%	0.13%	0.21%	**0.25%**	0.24%	0.05%
23	**0.89%**	0.63%	0.62%	0.68%	0.79%	**0.89%**	0.84%	0.36%
24	**0.24%**	0.18%	0.22%	0.22%	0.23%	**0.24%**	0.23%	0.10%
25	**0.82%**	0.50%	0.77%	**0.82%**	0.76%	0.74%	0.75%	0.29%

The new methodology has provided adequate clarifications and improvements to overcome deficiencies of the existing IEC methodology. It also created the flexibility for network planners to have maximum control in managing harmonic allocations in their network. The results shown above indicate that the methodology is very effective in utilising the *spare network supply capacities* to increase *global harmonic contributions* and harmonic allocations to loads while ensuring that planning levels are not exceeded. The *reserved spare capacities*, include allowance for future loads and safety margin, can be fully utilised to regulate the additional harmonic allocations to loads.

5.3.3 Determination of Individual Limits Based on the Proposed Modifications

In this case study, apart from the SVC as an existing harmonic current source that was previously allocated, Loads 2, 5, 11, 12 were assumed to be installed at the same time. In this scenario, the *global harmonic contribution* at each bus is evaluated and must satisfy seven conditions required for a 7-bus network as described above. It is required that each scenario is evaluated to identify the minimum contribution allowed. Once the global contribution is determined for each bus, it is distributed to loads connected to the respective bus, proportional to their MVA sizes.

The example below demonstrates how improved *global contributions (G_{hBm})* obtained from Sections 5.2.2 and 5.2.3 above can be fairly distributed to all loads connected to the applicable bus. It illustrates harmonic allocation for Load 11 and Load 12 connected to Bus 1, which has improved *global contribution (G_{hB1})* from 2.75% at 11th harmonic to 114.67% at 20th harmonic with zero safety margin. The *global contribution* should be fairly and equally distributed among loads, sharing the same connection point, according to their MVA sizes. It is recommended that the *global contribution (G_{hB1})* has sufficient *reserve capacity*, e.g. *$p = 10\%$*, for safety margin as discussed. In this scenario, the *global contribution (G_{hB1})* can be increased from 2.47% at the 11th harmonic to 86.35% at the 20th harmonic with a 10% safety margin.

a) *Total Supply Capacity* at Bus 1.

Equation (5.3) can be applied to Bus 1 and its connected loads as follows

$$S_{tS1} = S_{Load\ 11} + S_{Load\ 12} + S_{1R} + S_{1FL} + S_{1S} \tag{5.14}$$

b) Harmonic allocation for Load 11 can be based on (5.13).

There was no existing load before Load 11.

$$\left.\begin{array}{c} E_{U\ Load\ 11}(h) = \sqrt[\alpha]{\left(G_{B1}^{\alpha}(h) - \sum_j^n E_{U\ ExistingLoads_j@B1}^{\alpha}(h)\right)\left(\frac{S_{Load\ 11}}{S_{tS1}-\sum_j^n S_{ExistingLoads\_j@B1}}\right)} \\ \sum_j^n E_{U\ ExistingLoads_j@B1}^{\alpha}(h) = 0 \\ \sum_j^n S_{ExistingLoadsj@B1} = 0 \end{array}\right\} \xrightarrow{yields}$$

$$E_{U\ Load\ 11}(h) = \sqrt[\alpha]{(G_{B1}^{\alpha}(h) - 0)\left(\frac{S_{Load\ 11}}{S_{tSB1}-0}\right)} = G_{B1}(h)\sqrt[\alpha]{\left(\frac{S_{Load\ 11}}{S_{tSB1}}\right)} \tag{5.15}$$

c) Harmonic allocation for Load 12.

Load 11 is now considered as an existing load that was connected to Bus 1 before Load 12. Application of equation (5.13) to calculate harmonic voltage allocation to Load 12.

$$\left.\begin{array}{c} E_{U\ Load\ 12}(h) = \sqrt[\alpha]{\left(G_{B1}^{\alpha}(h) - \sum_j^n E_{U\ ExistingLoads_j@B1}^{\alpha}(h)\right)\left(\frac{S_{Load\ 12}}{S_{tS1}-\sum_j^n S_{ExistingLoads\_j@B1}}\right)} \\ \sum_j^n E_{U_{ExistingLoadsj@B1}}^{\alpha}(h) = E_{U\ Load\ 11}^{\alpha}(h) \\ \sum_j^n S_{ExistingLoadsj@B1} = S_{Load\ 11} \end{array}\right\} \xrightarrow{yields}$$

$$E_{U\ Load\ 12}(h) = \sqrt[\alpha]{[G_{B1}^{\alpha}(h) - E_{U\ Load\ 11}^{\alpha}(h)]\left(\frac{S_{Load\ 12}}{S_{tSB1}-S_{Load\ 11}}\right)} \tag{5.16}$$

d) Estimate the equivalent harmonic allocation for the *unused spare capacity* (E_{UhIS}) that has been shared with other buses to increase their *global contributions*.

$$\left.\begin{array}{c} E_{U\,Load\ 1S}(h) = \sqrt[\alpha]{\left(G_{B1}^{\alpha}(h) - \sum_j^n E_{U\,ExistingLoads_j@B1}^{\alpha}\ (h)\right)\left(\frac{S_{1S}}{S_{tS1}-\sum_j^n S_{ExistingLoads\_j@B1}}\right)} \\ \sum_j^n E_{U_{ExistingLoadsj@B1}}^{\alpha}\ (h) = E_{U\,Load\ 11}^{\alpha}(h) + E_{U\,Load\ 12}^{\alpha}(h) \\ \sum_j^n S_{ExistingLoadsj@B1} = S_{Load\ 11} + S_{Load\ 12} \end{array}\right\} \xrightarrow{yields}$$

$$E_{U\,1S}(h) = \sqrt[\alpha]{[G_{B1}^{\alpha}(h) - E_{U\,Load\ 11}^{\alpha}(h) - E_{U\,Load\ 12}^{\alpha}(h)]\left(\frac{S_{Load\ 1S}}{S_{tSB1}-S_{Load\ 11}-S_{Load\ 12}}\right)} \tag{5.17}$$

e) Estimate harmonic emission right that could have been allocated for the *reserved capacity* (E_{UIR}(h)) – safety margin.

$$\left.\begin{array}{c} E_{U\,1R}(h) = \sqrt[\alpha]{\left(G_{B1}^{\alpha}(h) - \sum_j^n E_{U\,ExistingLoads_j@B1}^{\alpha}\ (h)\right)\left(\frac{S_{1R}}{S_{tS1}-\sum_j^n S_{ExistingLoads\_j@B1}}\right)} \\ \sum_j^n E_{U_{ExistingLoadsj@B1}}^{\alpha}\ (h) = E_{U\,Load\ 11}^{\alpha}(h) + E_{U\,Load\ 12}^{\alpha}(h) + E_{U\,1S}^{\alpha}(h) \\ \sum_j^n S_{ExistingLoadsj@B1} = S_{Load\ 11} + S_{Load\ 12} + S_{Load\ 1S} \end{array}\right\} \xrightarrow{yields}$$

$$E_{U\,1R}(h) = \sqrt[\alpha]{[G_{B1}^{\alpha}(h) - E_{U\,Load\ 11}^{\alpha}(h) - E_{U\,Load\ 12}^{\alpha}(h) - E_{U\,1S}^{\alpha}(h)]\left(\frac{S_{1R}}{S_{tSB1}-S_{Load\ 11}-S_{Load\ 12}-S_{1S}}\right)} \tag{5.18}$$

The proposed modification for assessing the individual limits as shown in (5.19) conforms to the summation law and displays in (5.20) below because

$$S_{1R} = S_{tSB1} - S_{Load\ 11} - S_{Load\ 12} - S_{1S} \tag{5.19}$$

And

$$G_{B1}(h) = \sqrt[\alpha]{[E_{U\,Load\ 11}^{\alpha}(h) + E_{U\,Load\ 12}^{\alpha}(h) + E_{U\,1S}^{\alpha}(h) + E_{U\,1R}^{\alpha}(h)]} \tag{5.20}$$

It is important to note that the *unused spare capacity* to share among busbars has been deducted from the denominator terms of the Share Planning Levels equations (5.7) – (5.10). Therefore, the *spare capacity* to share no longer exists because it has been used to increase the global contribution at all buses. Subsequently, the allocation of individual limits for the *unused spare capacity* to share ($E_{U\,1S}$(h)) should not be included in the calculation of the total harmonic emission at the bus. The *total harmonic emission* at bus 1 would be expressed as:

$$E_{U\,B1}(h) = \sqrt[\alpha]{[G_{B1}^{\alpha}(h) - E_{U\,1S}^{\alpha}(h)]} = \sqrt[\alpha]{[E_{U\,Load\ 11}^{\alpha}(h) + E_{U\,Load\ 12}^{\alpha}(h) + E_{U\,1R}^{\alpha}(h)]} \tag{5.21}$$

The *total harmonic current injection*, which would be used to evaluate harmonic voltage compliance at Bus 1, is:

$$E_{I\,B1}(h) = \frac{E_{I\,B1}(h)}{Z_{1,1}(h)} \tag{5.22}$$

5.4 Summary

Several amendments to the IEC's method have been proposed to overcome existing deficiencies to improve its useability and effectiveness. They include: (i) proposed clarifications and modifications for redefining and assessing the *total loads* (S_t) and *total supply capacity* (S_{tSm}) of present network configurations only - excluding all future scenarios; (ii) proposed modification to the existing method for sharing planning levels between busbars in meshed HV-EHV systems to maximise the global harmonic contribution through the sharing of *unused spare capacities*; and (iii) proposed modification to the existing method for assessing individual limits to take into account of harmonic emissions from existing loads. The combined amendments have resulted in a new allocation methodology that has successfully overcome the exiting IEC report's deficiencies.

A case study was conducted and explained in details, with step-by-step examples, to demonstrate how the new methodology should be applied in practice to improve harmonic allocations. Maximum allowed *global harmonic contribution*, harmonic allocations and voltage compliance were recorded and assessed. The results have proven that the new allocation methodology has been very effective as it provided necessary clarifications and significant improvements to overcome deficiencies of the existing IEC methodology. Overall, its application has resulted in maximum improvement to harmonic allocations, from 2.75% up to 114.67% at certain harmonics and depend on network scenarios, by utilising the *spare supply capacity* to allow maximum global harmonic contributions at relevant loaded buses, while maintaining harmonic voltage compliance within the planning levels.

Furthermore, the new methodology demonstrated relevant procedures and flexible mechanisms for network planners to have maximum control on how they can regulate the global harmonic contributions and allocation to individual loads through the settings of the *reserved spare capacity*. The risks associated with the inaccurate estimation of uncertain future supplies, loads and network scenarios have been significantly reduced with the new allocation method. It is acknowledged that the new methodology is very effective for harmonic allocation to loads in transmission system based on a chosen network scenario only. However, it does not address the issues related to changes of harmonic impedances due to different network scenarios that could affect harmonic allocations as identified in Chapter 4. Therefore, the new method, i.e. IEC methodology with incorporated proposed amendments, could be further improved through the determination of the most relevant network scenarios to be used for harmonic allocation. This will be addressed in Chapter 8 through the optimisation of harmonic allocations to suit specific requirements, e.g. harmonic profiles, of different loads.

6 Evaluation of Harmonic Allocation Methodologies

6.1 Introduction

Management of harmonics currently vary across different transmission networks and the practical application of guidelines and standards can differ widely. It is influenced by the competency, expertise and experience of Transmission Service Operator (TSO) planners. Deficiencies of existing standards, as discussed in Chapters 2 and 3, can lead to misinterpretation of assumptions, inconsistent applications and ultimately poor harmonic management. TSOs thus heavily rely on established standards and methodologies to manage harmonics in their network. The question is which standard/methodology would be most suitable for harmonic allocation to transmission systems?

Chapter 2 has reviewed the conceptual differences of existing standards and methodologies. However, demonstration of the differences through practical applications in a realistic transmission network would provide in-depth knowledge as to how and why one methodology is more suitable for transmission systems than others. It also highlights potential issues and adverse consequences that can occur if an unsuitable methodology is used to allocate harmonics to loads in transmission systems. Network planners need to be aware of these advantages and disadvantages and their consequences to make an informed decision as to which methodology to employ.

In this chapter, the application of existing allocation methodologies, including the new methodology developed in Chapter 5 (IEC method proposed modifications), are compared through a practical harmonic allocation case study. The aim, based on results and analysis obtained, is to determine the most practical allocation method for transmission systems, such that maximum harmonic allocations to loads can be achieved fairly and equitably while ensuring compliance with their respective planning levels. While not all issues related to applications of the various standards/methodologies are addressed, the following work aims at contributing to further improvement of existing guidelines and provide recommendations that can be adapted to lead to a more practical and prudent harmonic management.

6.2 Evaluation of Practical Application of Existing Allocation Methodologies

6.2.1 Allocation Requirements

Allocations to loads in a realistic transmission network have been examined and compared in the following based on five allocation methods: (i) IEC report; (ii) New allocation method derived in Chapter 5; (iii) IEEE standard; (iv) ESAA method; and (v) AS-2279.2 (now obsolete). Key findings regarding allocation requirements already obtained from previous chapters are summarised in Table 6.1 below.

Table 6.1 – Comparison of Allocation Requirements

Allocation Requirements	New Method (Chapter 5)	IEC/TR	ESAA (One-Third Planning Level)	IEEE-519	AS-2279.2
Field Measurements for Allocation	No	No	No	No	Yes
Independent on future loads and future supply capacity prediction	Yes	No	Yes	Yes	Yes
Inclusion of background harmonics	Yes	No	No	No	Yes (Meas.)
Calculation of network impedances	Yes	Yes	No	No	No
Inclusion of remote amplifications (Influence Coefficients)	Yes	Yes	No	No	No
Independent of *SCP* at PCC	Yes	Yes	Yes	No	No
Inclusion methodologies to manage changes of network scenarios	No	No	No	No	No
Pre-connection Compliance Assessment	Yes	Yes	Yes	No	No
Post-commissioning Field-Measure Compliance Assessment	Yes	Yes	Yes	Yes	Yes
Ease in Practical Application	No	No	Yes	Yes	Yes
Suitable for realistic transmission systems	Yes	Yes	No	No	No

Key commentaries:

- Only AS-2279.2 requires pre-allocation measurements to determine background harmonics. Some practitioners also rely on field measurements for allocations. While this makes sense from an engineering approach, it may lead to contractual disputes later because existing loads may not have taken up their full allocations at the time the measurements were made.

- Allocation methodologies that rely on Short Circuit Ratio (*SCR*) to regulate harmonic allocations are unlikely suitable for realistic transmission systems as changes of harmonic impedances in transmission system is non-linear with frequencies as identified in Chapter 4. Characteristic of transmission network impedance is predominantly influenced by impedance and admittance of transmission lines, both of which are not linear with frequencies.

- None of the methodologies listed above, including the new method in Chapter 5, can manage harmonic allocations from a large number of network scenarios in transmission systems identified in Chapter 4. This deficiency will be addressed in Chapter 8.

- Only the IEC report and the new allocation methods have relevant allocation requirements that are suitable for transmission systems. The latter is more advanced as it includes improvements, as demonstrated in Chapter 5, to overcome deficiencies of the IEC method identified in Chapter 3.

- The commonality between the IEC report and the IEEE standard is that they both have recommended planning levels at PCCs and methodologies to allocate harmonic emissions to loads. However, the practical application of both planning levels and harmonic allocation methodologies are completely different and not compatible in their original form. It highlights the need to reference only one standard across multiple jurisdictions of an interconnected network. Different standards can be applied to isolated networks; however, the question is how different planning limits and different allocations will affect equipment tolerances and its susceptibility levels if the equipment is manufactured according to a common standard?

The practicality and effectiveness of the different harmonic allocation methodologies (i) - (v) were compared. Due to significant differences between the IEEE standard and the IEC report as discussed in Chapter 2 and above, the comparison focused only on harmonic allocations, which affect voltage performance in the network, concerning only one method, i.e. the IEC report. Practical applications of these allocation methods for loads in transmission systems were also evaluated. The following tasks were required:

(a) Establish a referenced planning level, e.g. the IEC report's recommended planning level in [10];

(b) Allocate harmonic currents or voltages according to requirements of relevant methods; and

(c) Evaluate pre-connection voltage compliance based on a common voltage calculation method, e.g. general summation law and alpha exponent in [10].

Voltage limits (planning levels) of all methods have been scaled/normalised to planning levels in the IEC report. The voltage or current allocations to individual loads were scaled relative to the normalized planning levels. Busbar harmonic voltages have been calculated using the summation law and alpha law as per the IEC method. The resulting voltages were then compared against their normalised planning levels for pre-connection compliance assessment.

6.2.2 Case Study Network

The case study network in Chapter 3 is repeated below in Figure 6.1. The network features a meshed network with long transmission lines at a high voltage level, large capacitor banks, large synchronous generators, large loads, and a static VAr compensator (SVC), which represents an existing harmonic source. Both capacitor banks and long transmission lines of the network contribute to multiple resonances, which are sensitive to changes in network scenarios. Harmonic voltages at PCCs can also increase or decrease depending on network scenarios, and large energy consumption loads provide effective impedance attenuation leading to lower harmonic voltages at relevant connection points.

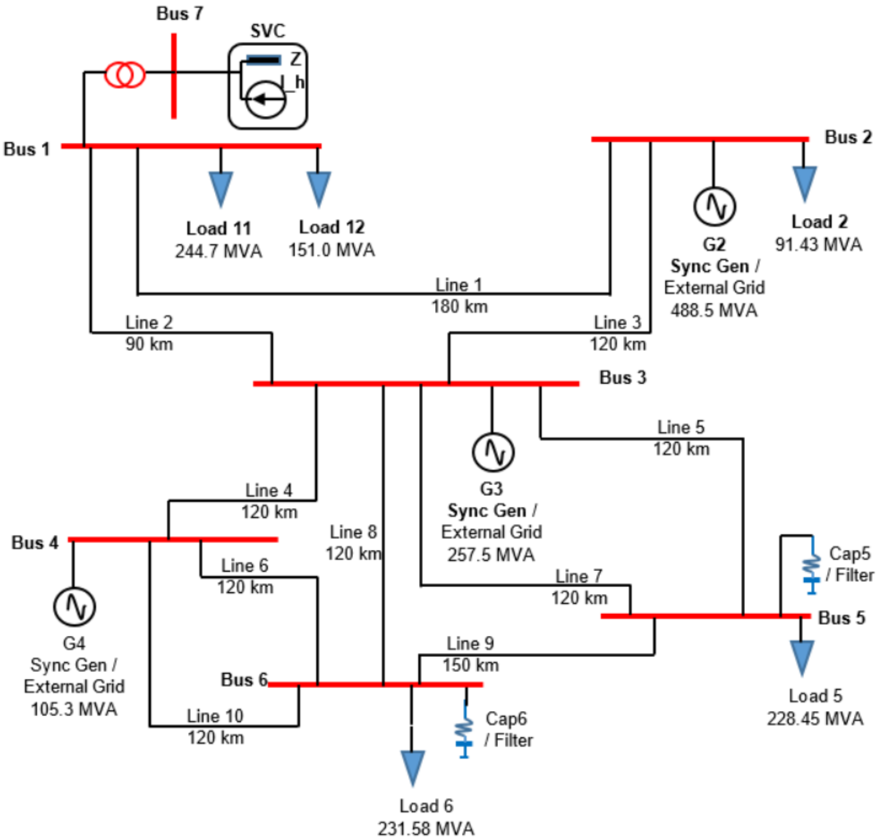


Figure 6.1 – 7-Bus 132kV Case Study Network – A Realistic Meshed Transmission Network

6.2.3 Normalised Planning Levels

Voltage limits of different allocation methods, as previously shown in Table 2.4, are scaled to IEC planning levels as shown in Table 6.2 below.

Table 6.2 – Harmonic Planning Levels (Voltage Limits) from Various Harmonic Allocation Standards

	IEEE519		IEEE519 Scaled to IEC		IEEE519		IEEE519 Scaled to IEC		AS 2279	AS 2279	One-Thrid	IEC 61000-3-6
	PCC	Load	PCC	Load	PCC	Load	PCC	Load	PCC	PCC	Load	PCC
h	V_{limit_PCC}	Max I_{h_Load}	IEC V_{limit_PCC}	Max I_{h_Load}	V_{limit_PCC}	Max I_{h_Load}	IEC V_{limit_PCC}	Max I_{h_Load}	V_{limit_PCC}	V_{limit_PCC}	Max V_{h_Load}	V_{limit_PCC}
	[> 161] kV		[> 161] kV		[69-161] kV		[69-161] kV		[22 - 66] kV	>= 110 kV	MV, HV & EHV	MV, HV & EHV
	I_{sc}/I_L <25		I_{sc}/I_L <25		I_{sc}/I_L <20		I_{sc}/I_L <20					
	%	%	%	%	%	%	%	%	%	%		%
2	1.0	N/A	1.400	N/A	1.5	N/A	1.400	N/A	1.0	0.5	0.467	1.400
3	1.0	1.000	2.000	2.000	1.5	2.000	2.000	2.667	2.0	1.0	0.667	2.000
4	1.0	0.250	0.800	0.200	1.5	0.500	0.800	0.267	1.0	0.5	0.267	0.800
5	1.0	1.000	2.000	2.000	1.5	2.000	2.000	2.667	2.0	1.0	0.667	2.000
6	1.0	0.250	0.400	0.100	1.5	0.500	0.400	0.133	1.0	0.5	0.133	0.400
7	1.0	1.000	2.000	2.000	1.5	2.000	2.000	2.667	2.0	1.0	0.667	2.000
8	1.0	0.250	0.400	0.100	1.5	0.500	0.400	0.133	1.0	0.5	0.133	0.400
9	1.0	1.000	1.000	1.000	1.5	2.000	1.000	1.333	2.0	1.0	0.333	1.000
10	1.0	0.250	0.350	0.088	1.5	0.500	0.350	0.117	1.0	0.5	0.117	0.350
11	1.0	0.500	1.500	0.750	1.5	1.000	1.500	1.000	2.0	1.0	0.500	1.500
12	1.0	0.125	0.318	0.040	1.5	0.250	0.318	0.053	1.0	0.5	0.106	0.318
13	1.0	0.500	1.500	0.750	1.5	1.000	1.500	1.000	2.0	1.0	0.500	1.500
14	1.0	0.125	0.296	0.037	1.5	0.250	0.296	0.049	1.0	0.5	0.099	0.296
15	1.0	0.500	0.300	0.150	1.5	1.000	0.300	0.200	2.0	1.0	0.100	0.300
16	1.0	0.125	0.279	0.035	1.5	0.250	0.279	0.046	1.0	0.5	0.093	0.279
17	1.0	0.380	1.200	0.456	1.5	0.750	1.200	0.600	2.0	1.0	0.400	1.200
18	1.0	0.095	0.266	0.025	1.5	0.188	0.266	0.033	1.0	0.5	0.089	0.266
19	1.0	0.380	1.074	0.408	1.5	0.750	1.074	0.537	2.0	1.0	0.358	1.074
20	1.0	0.095	0.255	0.024	1.5	0.188	0.255	0.032	1.0	0.5	0.085	0.255
21	1.0	0.380	0.200	0.076	1.5	0.750	0.200	0.100	2.0	1.0	0.067	0.200
22	1.0	0.095	0.246	0.023	1.5	0.188	0.246	0.031	1.0	0.5	0.082	0.246
23	1.0	0.150	0.887	0.133	1.5	0.300	0.887	0.177	2.0	1.0	0.296	0.887
24	1.0	0.038	0.239	0.009	1.5	0.075	0.239	0.012	1.0	0.5	0.080	0.239
25	1.0	0.150	0.816	0.122	1.5	0.300	0.816	0.163	2.0	1.0	0.272	0.816
THD_V	1.5		3.000		2.5		3.000					3.000
TDD_I		1.500		3.000		2.500		3.000				

6.2.4 Relationship between Transmission Network Impedance and Frequency

As discussed in Chapter 2, both the IEEE-519 and AS-2279.2 allocation methods rely on *SCR* at PCCs, while the IEC method and the new method (also derived from the IEC) rely on harmonic impedances. It was found that harmonic impedances in transmission systems change non-linearly with frequencies as shown for Bus 2, 3 and 4 in Figure 6.2 – 6.4 respectively (admittances are plotted instead of impedances). The green bars are harmonic admittances calculated from the realistic transmission network in Figure 6.1. A "moving average" trend line was also added for each graph. Orange bars are admittances, which has the same fundamental admittance of the realistic transmission network but its harmonic frequency quantities vary linearly with frequency (i.e. if it were assumed the network was inductive only). It clearly shows that realistic transmission network impedances do not vary linearly with frequencies due to their complex characteristics, which mostly contributed from long transmission lines and large capacitor banks, as discussed in Chapter 4. At lower frequencies, network impedance is more inductive hence impedance varies more linear with frequency – green and orange bars are very similar. However, at higher frequencies, differences between the green and orange bars are more obvious due to the influence of transmission line characteristics on the realistic network impedance.

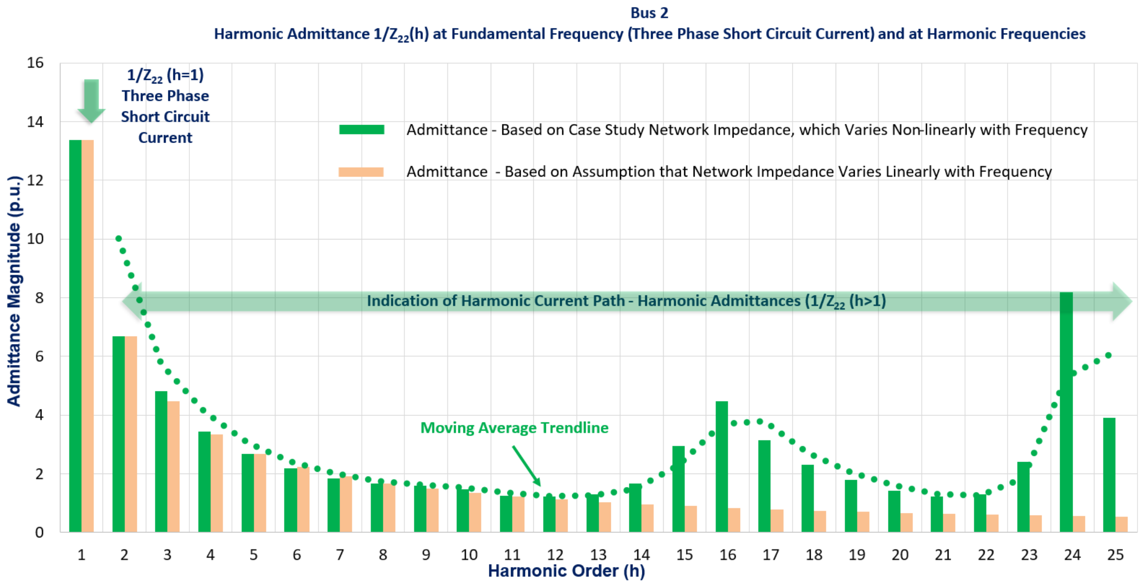


Figure 6.2 – Harmonic admittance at Bus 2 and its variations with frequency (1 / Z_{22} (h))

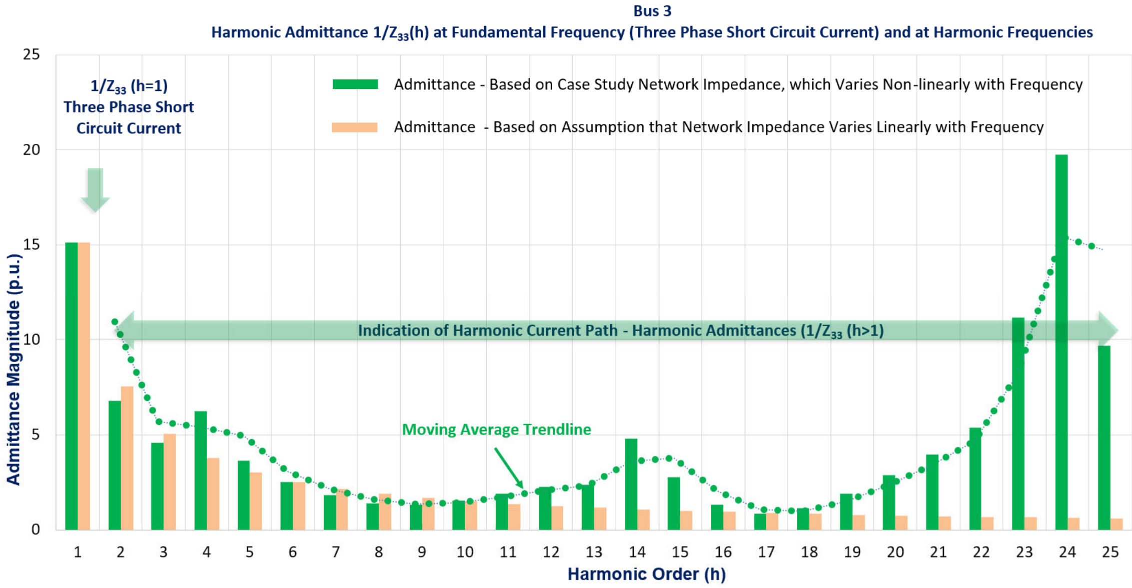


Figure 6.3 – Harmonic admittance at Bus 3 and its variations with frequency (1 / Z_{33} (h))

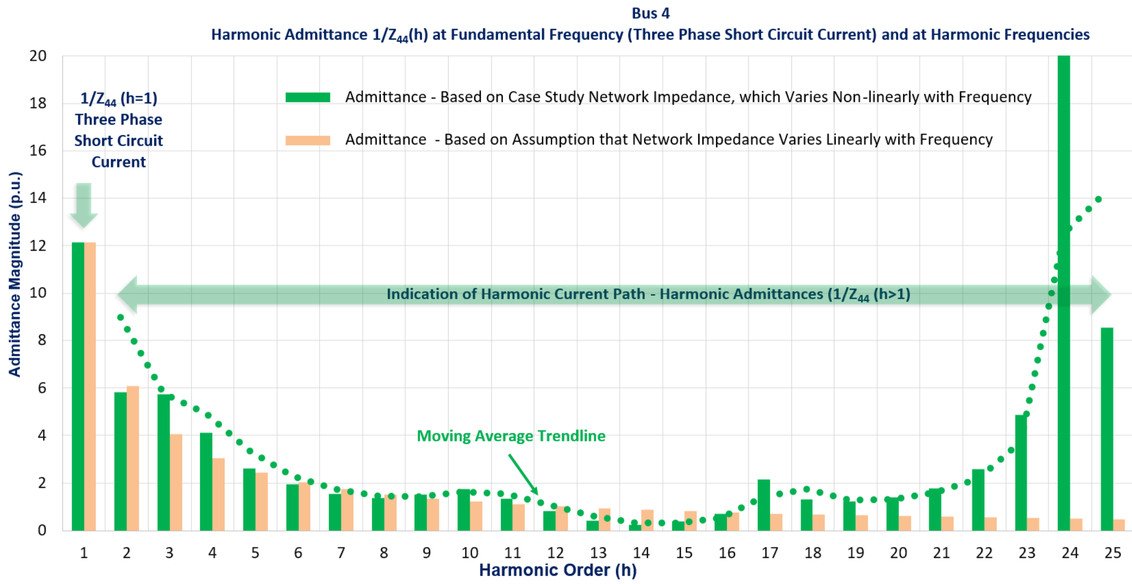


Figure 6.4 – Harmonic admittance at Bus 4 and its variations with frequency (1 / Z_{44} (h))

Chapter 4 emphasised that harmonic impedances in transmission network can change significantly depending on network scenarios. It was also pointed out that there are much higher chances of harmonic resonances in transmission network than in distribution network due to transmission lines and large capacitor banks. The best way that these resonance conditions can be accounted for is by using detailed network modelling to assess harmonic impedances, which are complex for transmission systems. Methodologies not using harmonic impedances would be less suitable for transmission systems as variations of impedances and resonance conditions are not properly accounted for. Given the complexity of transmission system impedances, the IEC and the new allocation methods (also derived from the IEC), which make use of network harmonic impedances, would be considered more suitable for transmission systems.

6.3 Case Study – Comparing Practical Harmonic Allocation Methodologies

Harmonic allocations were carried out for Loads 11 and 12 (Bus 1), Load 2 (Bus 2), and Load 5 (Bus 5) in the network of Figure 6.1. Harmonic currents allocated for loads at Bus 1, 2 and 5 are shown in Figures 6.5 - 6.7 respectively. Harmonic voltages were calculated based on the IEC report method, i.e. using the summation law and alpha exponents outlined in [10].

6.3.1 Option 1 – Existing IEC/TR 61000-3-6

This option included harmonic allocations to Loads 11 and 12 (Bus 1), Load 2 (Bus 2), and Load 5 (Bus 5), using the existing IEC report method. It was identified in Chapter 5 that this method heavily relies on: (i) the accuracy of the forecast of *total future loads* to be installed at a PCC; (ii) the method for sharing planning levels between HV-EHV busbars; and (iii) the method for allocation of individual limits. The methodology for sharing planning levels amongst HV-EHV busbars, which is defined by equation (14) in [10], is to ensure that *Maximum Global Contribution* at all busbars does not result in exceeding planning levels. Allocation using the existing IEC method was already demonstrated in Chapters 3 and 5.

Allocations to Loads 2, 5, 11, and 12, as shown in Figures 6.5, 6.6 and 6.7, resulted in busbar voltages complying with planning levels, mainly due to under-allocation. Over-allocation, which always results in planning levels being exceeded, can also occur if the estimation of total future loads exceeds supply capacity, harmonic absorption and impedance attenuation capabilities of the network as demonstrated in Chapter 3. It was observed that remote amplification, harmonic absorption capabilities and impedance attenuation at PCCs play a vital role in harmonic management. However, they are not effectively utilised by the existing methods.

6.3.2 Option 2 – New Method (Derived in Chapter 5)

A new harmonic allocation method has been derived and recommended in Chapter 5, based on the IEC method, to improve the practicality and effectiveness of the existing IEC method. Spare supply capacities at busbars, which inherently includes harmonic absorption and impedance attenuation capability, were utilised to increase harmonic allocation to loads.

The principle of the new method is that harmonic allocation should be proportional to the supply capacity, taking into account spare supply capacities at all busbars under the most credible network scenario/s. It removes uncertainties of estimated future loads. The supply capacity at connection points should be strategically planned, e.g. purposely reconfigure the network to allow higher supply capacity at some strategic PCCs, and maintained according to the network absorption and attenuation capabilities at that location.

As shown in Figures 6.5 - 6.7, this method results in maximum harmonic allocations, i.e. up to 30% increase in harmonic allocation, for all loads and also comply with planning levels. The main advantages of the new allocation method include:

- Strategic network planning can provide certainty for supply capacities across the network. In principle, busbars that are strategically planned for future load connection will be given higher capacity. This helps to remove the need to estimate future loads and future network augmentation.

- Unused spare capacities at busbars can be reserved as safety margins or shared among busbars to increase harmonic allocations to loads connected to other busbars.

6.3.3 Option 3 – ESAA (One-Third Planning Level) Method

This method is very similar to the AS 2279.2 method as far as a headroom approach is concerned. A headroom approach is simply making an allowance, or reserving some of the existing margins between present harmonic voltage levels and the planning levels, for both existing and future loads. The main assumption of this method is that background harmonics contribute to one-third of the planning level, the allocation for the proposed load should be one-third, and the remaining one-third is reserved for future loads.

It is understood that this method was derived before 1975 based on a very different distribution of harmonic-producing loads to what we have today. The question is can it be modified and improved based on the understanding we now have to meet today's situation? Based on the information gathered from Chapter 2 – 4, it is unlikely that this method is suitable for transmission systems as it does not take into account network impedances, which are complex and have direct influences on harmonic allocation for loads in transmission systems. Another deficiency of this method is that it assumes all loads have the same harmonic allocation regardless of their type, size and location in the network. In practice, load type, size and location can significantly influence harmonic spectrums and diversities across the transmission network.

Figures 6.5 – 6.7 have shown that allocated harmonic currents for Load 2 at Bus 2 and Load 5 at bus 5 are too high for some harmonics compared to the busbars capacity. Therefore, planning levels (voltage limits) at Buses 2 – 6 were exceeded, especially Bus 4 and 6 were exceeded by 235% and 260% respectively, as shown in Figure 6.8 below when all loads injecting into their allocated emissions.

6.3.4 Option 4 – IEEE-519 Method

This standard recommends the maximum allowable harmonic load currents as a percentage of the fundamental load currents, relative to *SCR at a PCC*. It implies that harmonic current distortion limits can be increased proportionally to the "*system strength*" (*SCR*) of the network at PCCs. While this may be fine for low order harmonics, it can cause some issues at high harmonic orders as discussed above due to non-linear changes of transmission network impedances at high frequencies.

In this case study, all loads were allowed to inject to their maximum allowable current limits at all harmonics as shown in Table 6.2. Total Harmonic Distortion (*THD*) limits were exceeded. In other words, this standard inherently assumes that there are diversity factors across the harmonic spectrum of each load – not all harmonic currents reach limits at the same time. This assumption can potentially create issues as load owners may gradually increase their existing loads as long as all harmonic currents are at or below the maximum limits. This issue, where all loads inject to their maximum allowable harmonic currents, has been demonstrated and results are shown in Figures 6.5 – 6.7. This method resulted in too little current allocations for Loads 11 and 12 at Bus 1, and too high currents for Load 5 at Bus 5, compared to their PCCs' capabilities. As a result, planning levels were exceeded at Buses 2 – 6, especially Bus 4 -6 voltages were above 600% of planning level as shown in Figure 6.9. Overall, this method does not have procedures to ensure that allocations are proportional to the supply capacity, voltage amplification, impedance attenuation and absorption capabilities at PCCs in the network.

6.3.5 Option 5 – AS 2279.2 Method

The AS 2279.2 standard has been obsolete. It focuses on the harmonic voltage headroom at each PCC. Table 6.2 shows that each voltage level has only one limit for all odd harmonics, and one limit, which is half of the odd harmonic limit, for all even harmonics at each PCC. This standard implies that there are no diversity factors among different odd harmonics and the same intention applied for even harmonics. However, it included diversity factors for multiple converter loads connected to the same busbar, which is interesting.

Case study results have shown that even if allocated harmonic voltages for individual loads are significantly reduced to only 25% of planning limits at the PCCs, and a maximum diversity factor of 0.5 is applied, planning levels were exceeded. Similar to the IEEE standard and ESAA (one-third planning level) method, this method does not have any process to ensure that allocations are proportional to the supply capacity, voltage amplification, impedance attenuation and absorption capabilities at PCCs in the network.

Allocated harmonic currents for Load 2 at Bus 2 and Load 5 at Bus 5 are too high at some harmonics. Therefore, planning levels were exceeded at Bus 3, 5 and 6 as shown in Figure 6.10 below.

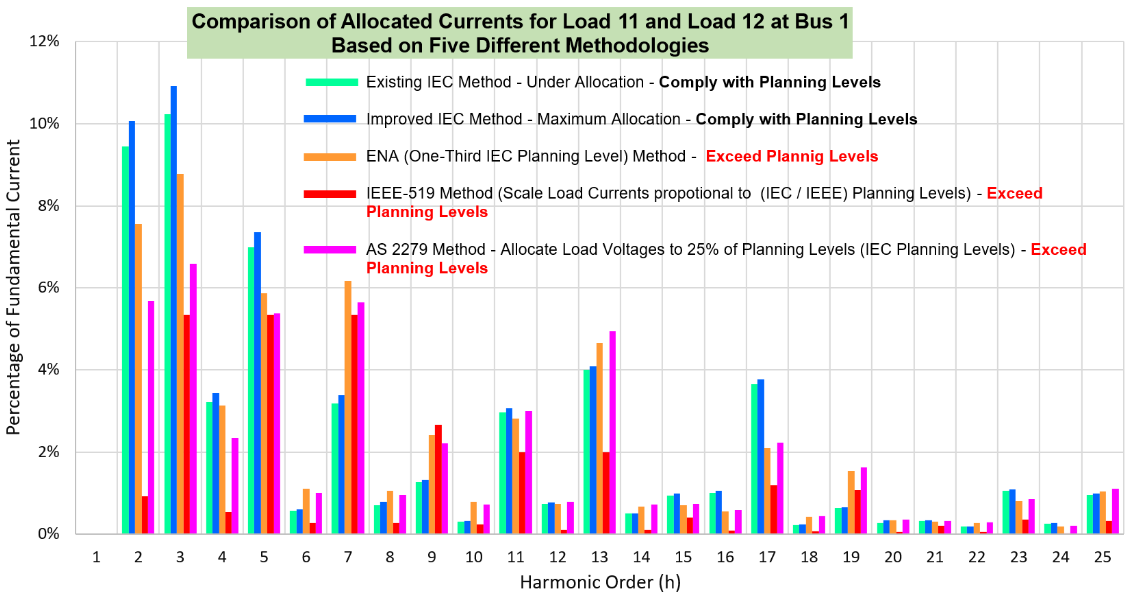


Figure 6.5 – Comparison of Harmonic Allocations for Load 11 and Load 12 at Bus 1, Based on Five Different Methodologies

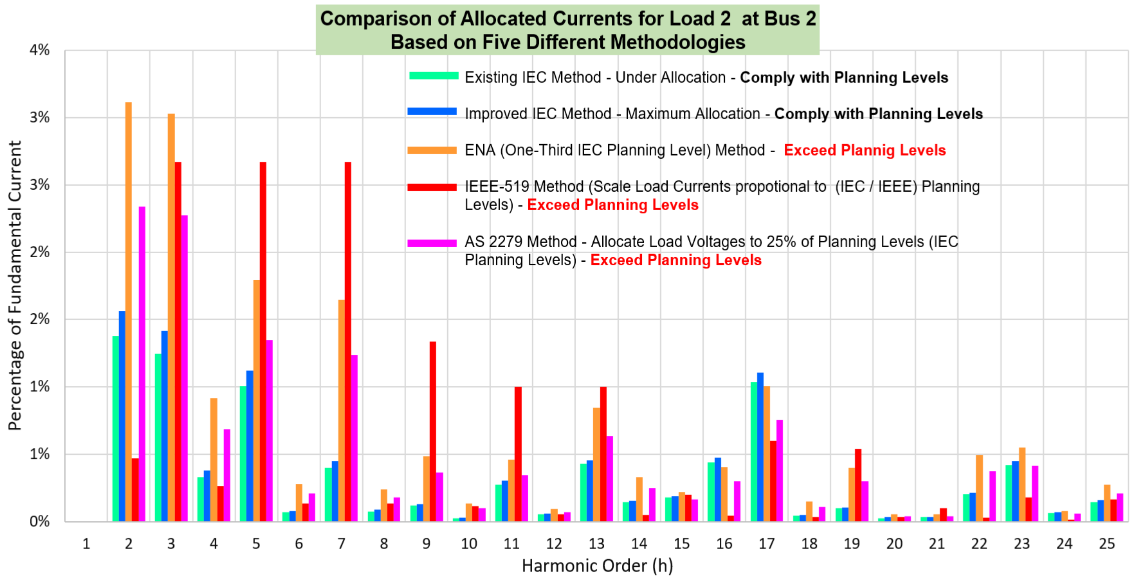


Figure 6.6 – Comparison of Harmonic Allocations for Load 2 at Bus 2, Based on Five Different Methodologies

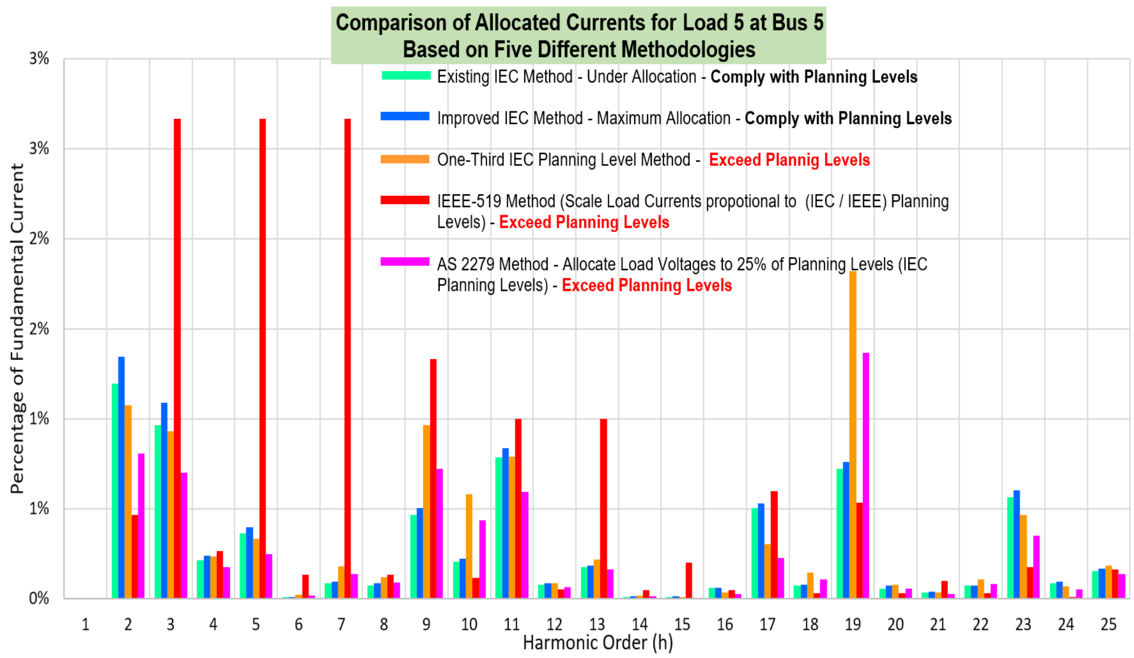


Figure 6.7 – Comparison of Harmonic Allocations for Load 5 at Bus 5, Based on Five Different Methodologies

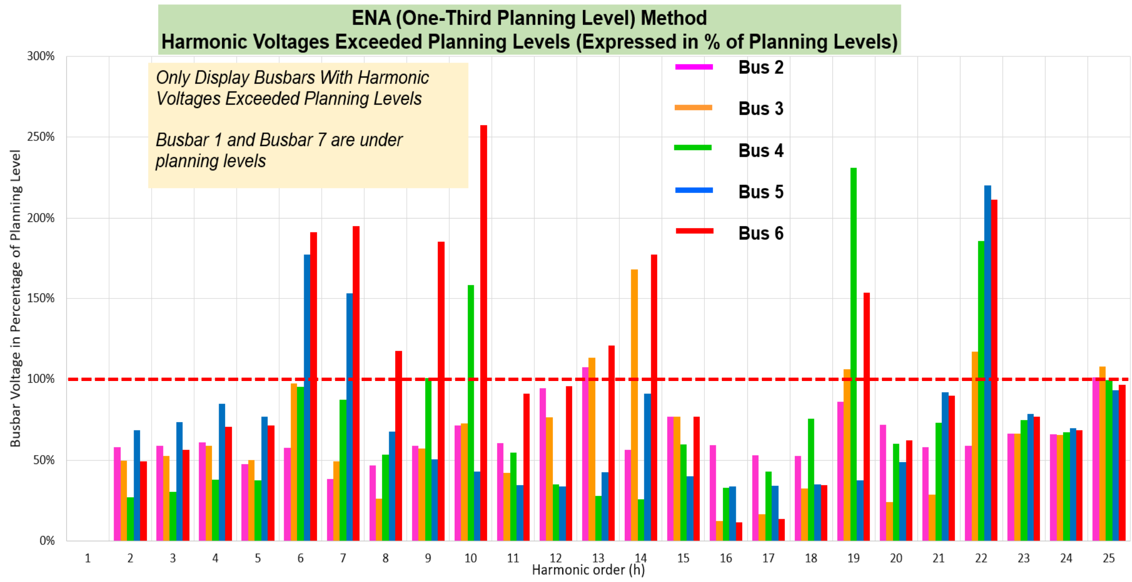


Figure 6.8 – ESAA (One-Third Planning Level) Method – Harmonic Voltages Exceeded Planning Levels

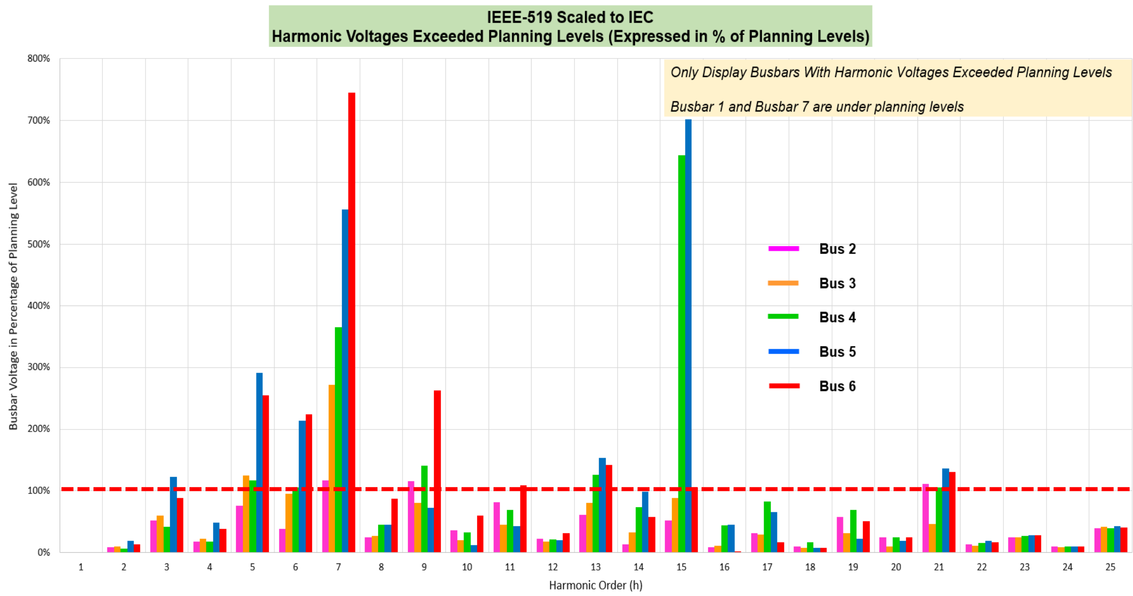


Figure 6.9 – IEEE-519 Scale to IEC – Harmonic Voltages Exceeded Planning Levels

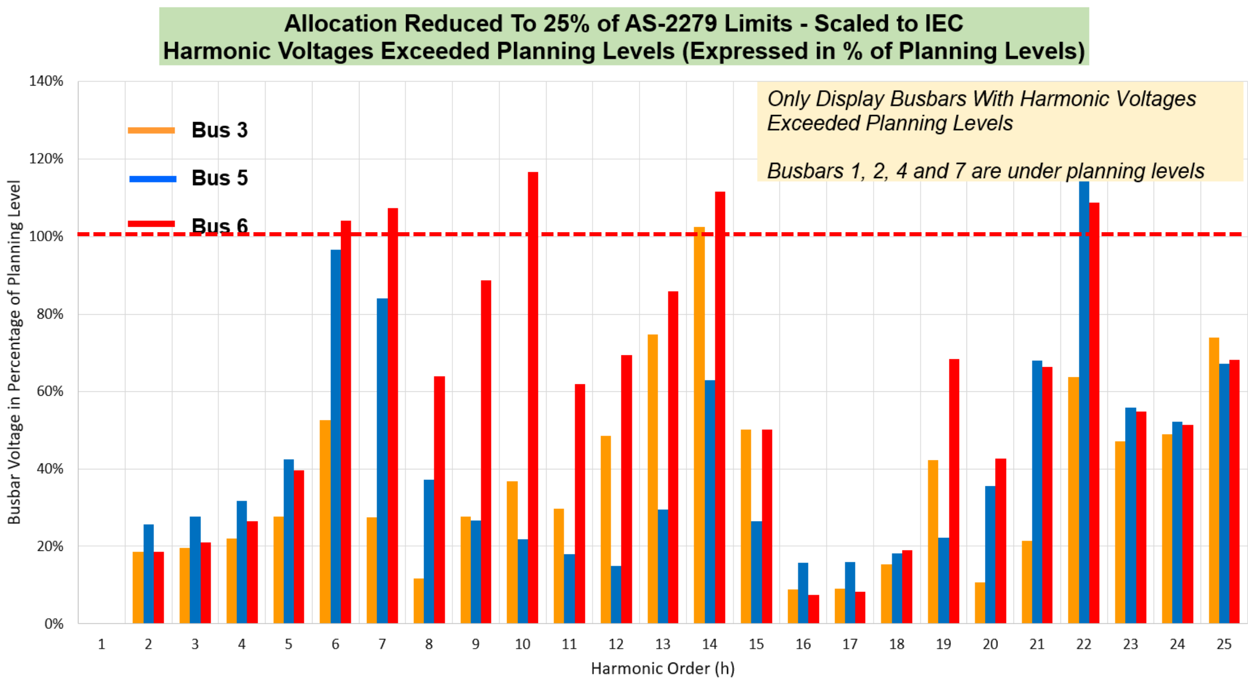


Figure 6.10 – AS2279 Method Scale to IEC – Harmonic Voltages Exceeded Planning Levels

6.3.6 Comparison of Allocation Results

Figures 6.5 – 6.7 above showed that only the IEC report and the new allocation method, which was also based on the IEC report method as discussed in Chapter 5, resulted in busbar voltages comply with planning levels.

Busbar voltages resulted from other allocation methods, e.g. ESAA (One-Third Planning Level), IEEE-519 and AS-2279.2, exceeded planning levels by very large margins as shown in Figures 6.8 – 6.10. Harmonic allocation using the AS-2279 standard was reduced to only 25% of the recommended level, but still resulted in voltages exceeded planning levels. Only the IEC and the new methodologies have appropriate procedures to ensure that planning levels will not be exceeded. The new method achieved *Maximum Total Harmonic Current and Voltage Distortions* (THD_I and THD_V), which are ranked from best to worst in Table 6.3. In this case study, *THD* is used as a second criterion to analyse differences in harmonic allocations. Allocation methods that do not have procedures to take harmonic impedances and *Influence Coefficients* into account result in lower *THD* and cause harmonic voltages exceeding planning levels. Based on the results shown in Figures 6.5 – 6.10, it can be concluded that the new (method) and IEC methods are suitable for harmonic allocations to loads in transmission systems. The new allocation method is considered the best.

Table 6.3 – Total Harmonic Distortions Based on Allocation Methodologies

Allocation Methodologies	THD_I (%)	THD_V (%)	Bus Voltages are Compliant to Planning Levels
New Method (Chapter 5)	18.64	3.12	Yes
IEC / TR	17.61	2.96	Yes
ESAA (One-Third Planning Level)	16.31	2.79	No
IEEE-519	10.24	1.89	No
AS-2279.2	13.95	2.51	No

Five allocation methodologies have been ranked based on their practical application and performance, which are considered relevant and suitable for transmission systems, as shown in Table 6.4.

Table 6.4 – Ranking of Harmonic Allocation Methodologies from Best to Worst

Harmonic Allocation Methods	Exceed Planning Levels	Recommendation Ranking from Best (5) to Worst (1)
New Method (IEC/TR 61000-3-6:2008, Ed. 2 With Amendments)	No	5
Existing IEC/TR 61000-3-6:2008, Ed. 2 Without Amendments	No – Under-allocation Yes – Over-allocation	4
ESAA (One-Third Planning Level) Method	Yes – Lower Chances *Depend on the remaining network absorption*	3
IEEE-519: 2014	Yes – Higher chances *Depend on the remaining network absorption*	2
AS-2279.2 (Obsolete)	Yes – Often	1

6.4 Summary

Practical application of five different harmonic allocation methods, including the IEC method, a new method (derived in Chapter 5), ESAA (One-Third Planning Level), IEEE-519 and AS-2279.2, have been examined and evaluated in detail using a realistic transmission network model. Key allocation requirements from these allocation methods were compared and analysed.

Only the IEC and new methods can ensure harmonic voltages comply with planning levels and provide maximum THD_V or TDD_I. The main reasons being that the IEC and the new method have relevant procedures to take into account harmonic impedances and *influence coefficients*, which are critical to transmission systems. They both have appropriate processes, e.g. sharing planning level equations, to ensure that *maximum global contributions* at PCCs will never exceed planning levels. Both the *influence coefficients* and *maximum global contributions* at PCCs are major attributes of the IEC report and the new allocation methods. However, the IEC report method often results in under-allocation due to its deficiencies identified in Chapter 3. The new method includes several improvements, as recommended in Chapter 5, to overcome deficiencies of the IEC method.

The ESAA method is simple to apply and somewhat similar to the AS 2279.2 method. Harmonic allocation obtained from this method resulted in planning levels being exceeded by a considerable level. The main issue of this method is that it does not take into account harmonic amplification, impedance attenuation and harmonic absorption capabilities at different busbars.

The IEEE-519 and AS-2279.2 methods rely heavily on *SCR* at PCCs, which are not closely linked to harmonic impedances in transmission systems, especially at high frequencies. The correlation between the *SCR* at a fundamental frequency and harmonic impedances, currents and voltages could not be established. Their dependency on *SCR* is the main reason that leads to lower THD_V or TDD_I and busbar voltages exceeded planning levels. They lack clarity, processes and likely produce undesirable harmonic allocations that can lead to contentious challenges between the network utility and other network participants.

It is important to note that the philosophy of IEEE 519 is one of "shared responsibility" wherein all users are allocated a certain current emission and, if the resultant voltage disturbance levels exceed defined limits, action is required by the network operator. It is not anticipated that having all network users producing their allowable current emissions will lead to voltage disturbance levels equal to the given target values. The fundamental premises and philosophies of the IEEE and IEC approach are different. Therefore, it is not unexpected that any results obtained will be equally different.

The most suitable allocation method for transmission systems is the new allocation method derived in Chapter 5. It was based on the IEC method, with improved modifications designed to overcome deficiencies of the existing IEC method. It significantly improves harmonic allocations to loads, i.e. achieves maximum harmonic allocations, while ensuring compliance with planning levels at PCCs. More importantly, the new method provides network planners flexible tools to manage harmonic allocations in a fair, equitable manner according to network characteristics and capabilities, e.g. impedance attenuation and harmonic absorption capability, at relevant PCCs. The new allocation method is recommended for harmonic allocation to loads in transmission systems.

7 Allocation to Renewable Generators

7.1 Introduction

Large wind and solar plants have become popular alternatives to conventional thermal generating plants as outlined in Chapter 2. Without long-term investment in large base-load thermal and hydro generators, wind, solar and battery plants are likely to become the main generation sources of future power systems. Such plants rely on power electronic converters, which produce significant harmonic emissions [6]. The performance of their control systems, e.g. phase lock loop function, can be affected by the distorted voltage and current waveforms due to harmonics [2 – 8]. Converter harmonic emission magnitude and frequency profiles can vary widely depending on their control system, switching frequency, level of power modules [29], and cost. Converter manufacturers often employ different control system algorithms to minimise harmonic emissions from their plants. However, even with the best intention, these plants still generate considerable harmonics at PCCs and often require in-built capacitors/harmonic filters that in turn add more capacitances to the network and lead to higher chances of harmonic resonances. Accordingly, power electronic converter based generation presents new challenges to the network operators, plant owners and consumers [2].

Transmission System Operators (TSOs) are solely responsible for managing harmonics in their network. TSOs have been looking for innovative solutions and methodologies, with respect to harmonic allocations, to accommodate more renewable generators in their networks. A new harmonic allocation methodology was derived in Chapter 5 to overcome some of the existing challenges, and its practical application for loads in transmission systems was assessed via case studies in Chapter 6. In this chapter, the new method is specifically applied to allocate harmonics to large solar or wind plants connected to an existing transmission network. It also examines and recommends options that can be considered to improve harmonic management for transmission networks with pending high penetration of renewable sources.

7.2 Case Study Network and Recommended Harmonic Allocation Methodology

7.2.1 Case Study Network and Assumptions

The case study network used here is an extension of previous case studies conducted in Chapters 3, 4, 5 and 6. The original 7-bus 132 kV network used in these chapters has been augmented to become a 10-bus 132 kV network and includes three large scale renewable generators - two solar farms (*G8* and *G9*) and one wind farm (*G10*) - as shown in Figure 7.1. This network reflects changes that have already occurred and anticipation of future changes that may eventuate to a number of real transmission systems in Australia. It essentially includes three large renewable generators connected to new remote substations, which are linked to the traditional network via long transmission lines. In addition to characteristics of the existing network identified in previous chapters, this network includes new features that are unique to renewable generators connected to remote busbars in transmission systems as follows:

- Significant increase of harmonic sources from renewable converters;
- Potential negative resistance behaviour as discussed in Chapter 4 due to interactions between DC converters and AC system impedances. This is not currently in the scope of the thesis;
- Low SCRs at renewable PCCs;
- Low harmonic absorption capability and high chances of harmonic resonance at renewable generators' PCCs due to new remote busbars.

Wind and solar farms, which are often installed at remote buses via long transmission lines, have considerable medium voltage, e.g. 33 kV, cables, step-up transformers and sometimes capacitors/harmonic filters on the generator side of PCCs. In practice, these MV network elements also contribute to changes of network harmonic impedance that can affect harmonic allocations as discussed in Chapter 4. They have been deliberately omitted in this case study to limit the complexities involved.

The following assumptions have been applied to this case study to resemble real changes that have occurred to some operational networks with high renewable penetration.

- The combined *total supply capacity* of wind and solar farms, (*G8*), (*G9*) and (*G10*) generators, is approximately 970 MVA compared to 851 MVA of the existing synchronous generators (*G2*), (*G3*) and (*G4*);
- When renewable generators are generating at their maximum output, Synchronous Generators (*G2*), (*G3*) and (*G4*) remain in service and run as synchronous condensers, i.e. connected to the network, supporting voltages and *SCP*;
- The base case network scenario represents the system intact with all generators (synchronous and asynchronous), loads and capacitor banks in service;
- The total supply capacity, network absorption and impedance attenuation at existing PCCs remain the same as previous case study networks, but much lower at new renewable PCCs;
- Prior to the installation of renewable generators, maximum harmonics were allocated to existing Load 2, 5, 6, 11 and 12 as per the new harmonic allocation methodology recommended in Chapter 5;
- All existing loads take up their full allocations, ignoring variation of harmonic spectrums of different types of loads or renewable generators;
- Station loads (energy consumption loads) at Bus 8, 9 and 10, where renewable generators (*G8*), (*G9*) and (*G10*) are connected respectively, are very small, typically below 5% of the plants' generating capacity;

- Prior to the connection of three new renewable generators, the remaining network absorption capability was only 10%, which is measured based on the remaining *total supply capacity* at existing PCCs;
- The supply capacities at busbars are defined by equation (5.2), as proposed for the new allocation method in Chapter 5. The reserved spare capacity, (S_{mR}), as defined by equations (5.4) and (5.5) – surplus supply capacity reserved for future loads, was approximately 10% (equivalent to about 85 MVA) of the *total supply capacity* limits (851 MVA).

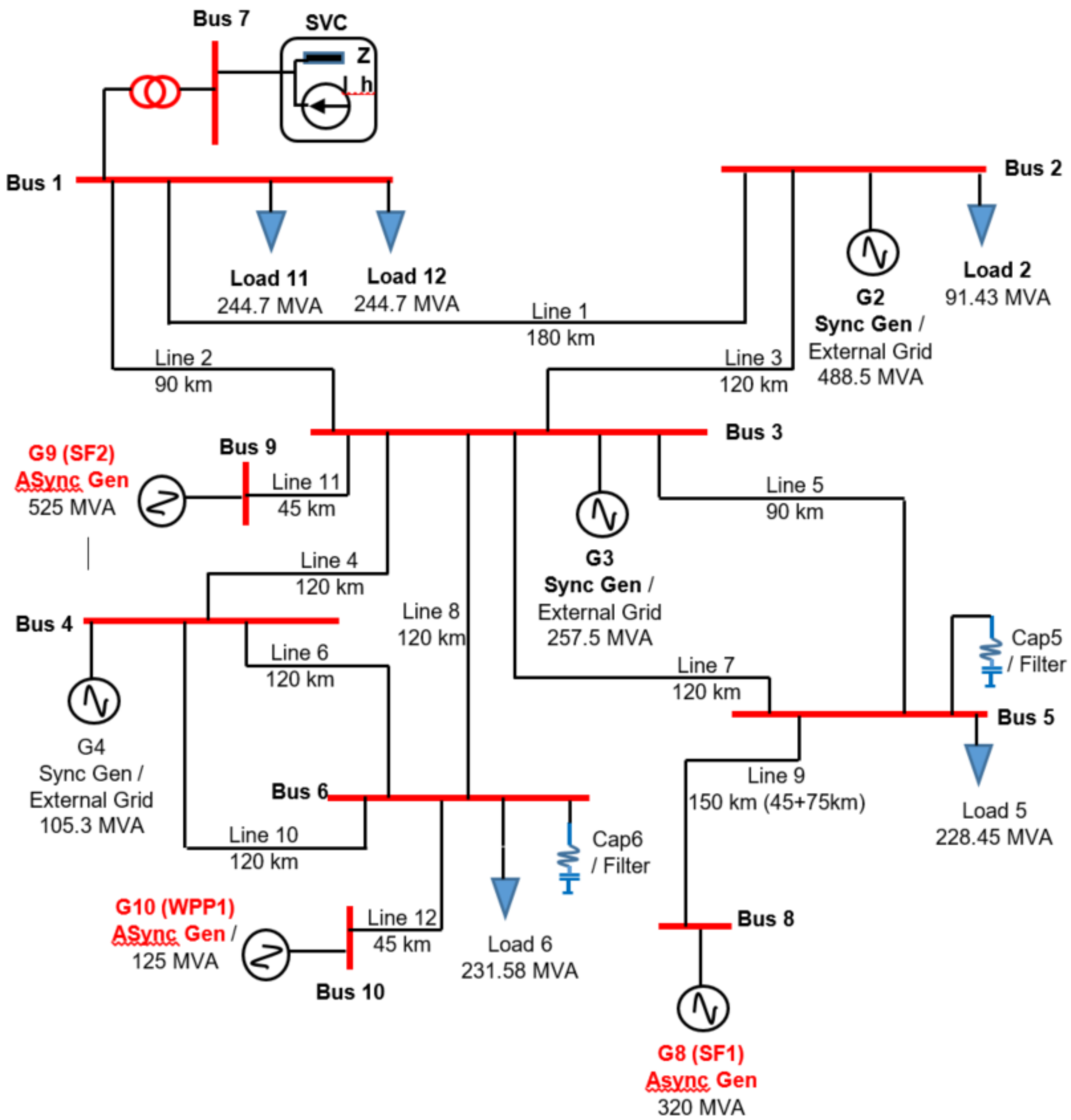


Figure 7.1 – Case Study 10-bus 132 kV Network

7.2.2 Application of New Allocation Method for Renewable Generators

The new methodology, derived in Chapter 5 for transmission systems, was applied to allocate harmonics to wind and solar farms in this case study. It was designed to achieve *maximum global contribution* (G_{hBm}) at PCCs through the effective utilisation of network absorption capability and impedance attenuation, which are predominantly provided by synchronous rotating generators and energy consumption loads respectively. They are represented by the supply capacity (S_{tS}) supplying loads at PCCs as per (7.3). Network elements were modelled as per the CIGRE guidelines [22]. Key aspects of the recommended allocation methodology are repeated below for clarity:

- Adhere to the summation law and α constants as per equations (7.1) and (7.2). This needs to be satisfied for all buses, across all harmonics, with exponent α selection as per Table 7.1.
- *The global harmonic contribution* of a bus is proportional to the *total supply capacity* (S_{tS}) of that bus. (S_{tS}) should be strategically planned to accommodate all present loads connected to the bus, plus any spare capacity reserved for future loads, safety margin or shared with other buses. The proposed amendments in Chapter 5 for the assessment of capacity at bus m (S_{tSm}) is given by equation (7.3).
- Assessment of *total supply capacity* (S_{tS}) must ensure that any changes, e.g. due to network reconfiguration, will not cause adverse effects to existing network participants.
- *Total supply capacity* (S_{tS}) is interpreted as the apparent power that can be *imported* to a bus, satisfying applicable contingency limits.
- *Global contribution* (G_{hBm}) at PCCs can be increased/decreased by adjusting the *spare/reserved capacity* (S_{mS}) as expressed in (7.4) for sharing planning levels.
- Estimated harmonic voltages calculated based on the IEC report method, i.e. summation law and α constants from [10].
- Method for assessing individual limit uses (7.5) to account for emissions from existing loads at PCCs.
- For allocation purposes, variation of harmonic spectrums of different types of loads are ignored and all harmonic loads at the PCC inject their maximum allocation.
- More detailed explanations of terminologies used in these equations can be found in Chapter 5.
- The new allocation method was based on an assumption that harmonic allocation is relative to the size of energy consumption loads, which inherently contribute to harmonic absorption and impedance attenuation effects. It can be said that both factors underpin the foundation for all existing harmonic allocation methodologies. In other words, both the network absorption capability from synchronous rotating machines and impedance attenuation from energy consumption loads are key parameters to be considered for harmonic allocation. The lack of either element can lead to the reduction of harmonic allocations unnecessarily.

$$\left(K_{h1-m}^{\alpha}\left(\sum\nolimits_{i\ at\ B1} E_{Uhi}^{\alpha}\right)+K_{h2-m}^{\alpha}\left(\sum\nolimits_{i\ at\ B2} E_{Uhi}^{\alpha}\right)+\cdots+K_{hn-m}^{\alpha}\left(\sum\nolimits_{i\ at\ Bn} E_{Uhi}^{\alpha}\right)\right)^{\frac{1}{\alpha}} \leq L_{hHV-EHV} \tag{7.1}$$

$$Where\ \sum\nolimits_{i\ at\ Bj} E_{Uhi}^{\alpha} \leq G_{hBj}^{\alpha} \tag{7.2}$$

Table 7.1 – Harmonic Summation Exponent from [10]

Harmonic (h)	Alpha (α)
$h < 5$	1
$5 \le h \le 10$	1.4
$h > 10$	2

$$S_{tSm} = \left[\sum_{i=1}^{n} S_{Gen\_i} + \sum_{x=1}^{n} S_{Import\_Power\_x}\right] - \left[\sum_{j=1}^{n} S_{Existing\_Loads\_j} + \sum_{y=1}^{n} S_{Export\_Power\_y}\right] \quad (7.3)$$

$$G_m(h) \le \sqrt[\alpha]{\frac{S_{tSm}}{K_{1-m}^{\alpha}(h)\times(S_{tS1}-S_{1S})+K_{2-m}^{\alpha}(h)\times(S_{tS2}-S_{2S})+..+K_{n-m}^{\alpha}(h)\times(S_{tSn}-S_{nS})}} \times L_{HV-EHV}(h) \quad (7.4)$$

$$E_{U\,i}(h) = \sqrt[\alpha]{\left(G_m^{\alpha}(h) - \sum_j^n E_{Existing\_Loads\_j@m}^{\alpha}(h)\right)\left(\frac{S_i}{S_{tSm}-\sum_j^n S_{Existing\_Loads\_j@m}}\right)} \quad (7.5)$$

7.3 Harmonic Allocation to Renewable Generators

7.3.1 Responsibilities and Procedures for Transmission System Operator

The TSO is responsible for setting planning levels, allocating harmonics to renewable generators at PCCs and ensuring that harmonic voltages are compliant with planning levels at all busbars. The TSO often provides network harmonic impedances, colloquially known as polygon plots (one plot for each harmonic order at the proposed PCC) and "preliminary" harmonic allocations for the Renewable Proponent (RP) to demonstrate their pre-connection compliance at their PCC. Polygon plots are harmonic impedance envelopes based on polar plots of the worst-case credible network scenarios. Polygon plots that apply to this case study network will be illustrated in Chapter 8. "Credible network scenarios" should be defined as network scenarios that represent 95th percentile weekly values of rms voltages (rms of individual harmonics over a 10-min period) not exceeding planning levels at all buses in the network, i.e. not just at the proposed PCC.

7.3.2 Proposed Responsibilities and Procedures for Renewable Proponents

The Renewable Proponent (RP) must demonstrate compliance of their plant at the proposed PCC taking into account their plant harmonic performance, cables, transformers, reactors, capacitors and harmonic filters. The RP provides design parameters of generator configurations – including relevant models of converters, cables, transformers and capacitors – to the TSO for re-evaluation of harmonic voltages at all network buses. Based on the new plant parameters, the TSO carries out the final harmonic voltage assessment to ensure that harmonics are still compliant with planning levels and no adverse effects at any buses. The preliminary allocation may require readjustment at this point to ensure these conditions are satisfied.

This chapter includes an evaluation of harmonic voltages at all buses. However, it only considers harmonic injections based on allocated levels and ignores variation of different harmonic spectrums, associated with cables, transformers, reactors and capacitors. In practice, these should be included as far as practicable because they can contribute to the amplification of background harmonics.

7.3.3 Fundamental Information and Renewable Generator Harmonic Model

This case study carries out a harmonic allocation to three renewable generators *G8*, *G9* and *G10*, as shown in Figure 7.1, using the new allocation method recommended in Chapter 6. This method was used to allocate harmonics to existing non-linear loads - Load 11, 12, 2, 5 and 6. Before the connection of three renewable generators, these existing loads take up their full allocations. The existing network absorption capability and impedance attenuation effects were effectively utilised such that only a very small margin, approximately 10%, remained in the network as described above. Harmonic voltages at all buses were below planning levels as demonstrated in Chapters 5 and 6.

Harmonic allocations are required for the connection of three renewable asynchronous generators, 320 MVA Solar Farm 1 (*G8*), 525 MVA Solar Farm 2 (*G9*) and 125 MVA Wind Farm 1 (*G10*). Their *station load*, (S_i) is the same as the *total load* (S_t) and *total supply capacity* (S_{tS}) at Buses 8, 9 and 10, respectively, are shown in Table F.1 in Appendix F. Renewable generators are modelled with their station loads (energy consumption loads) and harmonic source as shown in Figure 7.2. Only relevant data required for harmonic allocation, extracted from Table F.1, are shown in Table 7.2 for clarity. The new harmonic allocation method is based on load size proportional to the *total supply capacity* at the PCC. In this chapter, two allocation options are considered: (i) option 1 – allocation is based on MVA size of loads (energy consumption loads) as per the new harmonic allocation method; (ii) option 2 – allocation is based on generators' MVA rating.

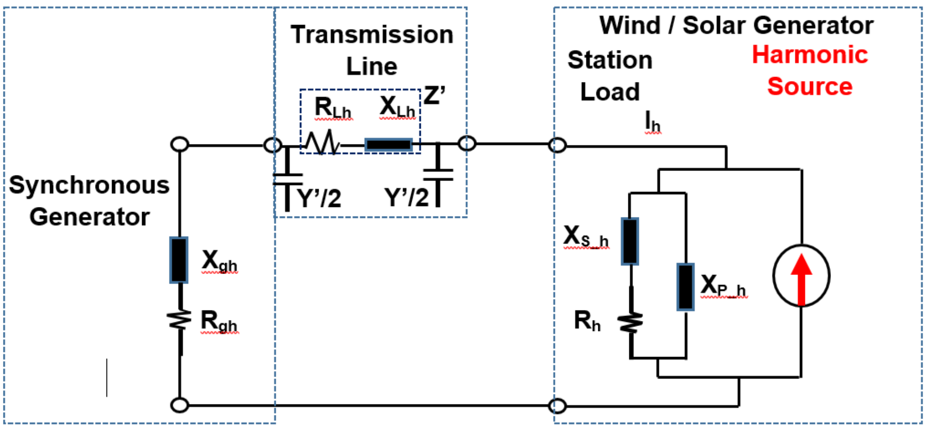


Figure 7.2 – Simplified Renewable Generator Model Connected to Traditional Transmission Network

Table 7.2 – Generators G8, G9 and G10 – Relevant Data Required for Allocation

PCC	Bus 8	Bus 9	Bus 10
Plant Name	**G8**	**G9**	**G10**
Plant Type	**Solar**	**Solar**	**Wind**
Generator Output Capacity (MVA)	**320**	**525**	**125**
Total New Load S_i *(*= 5% of Generator Output Capacity (MVA)	**16.00**	**26.25**	**6.25**
Total Supply Capacity *(*S_{tSm}*)* (MVA, According to (7.3))	**16.00**	**26.25**	**6.25**
Total Existing Loads	0	0	0
Total Export Power (MVA) at PCC	320	525	125

7.3.4 Option 1 - Allocation Based on Load Size

The new method allocates harmonics to loads according to their load size (S_i). In this case, S_i at renewable PCCs, i.e. Bus 8, 9 and 10, is very small, often less than 5% of its generating capacity, however, their harmonic sources are proportional to their generating (MVA) capacity – very significant harmonic sources.

Equation (7.3) was applied to determine the total supply capacity (S_{tSm}) at PCCs of generators *G8 (Bus 8), G9 (Bus 9) and G10 (Bus 10) as* shown in Table 7.2 above. Equation (7.4) was applied to find the maximum global harmonic contribution that satisfies 10 conditions of a 10 bus system. Allocations to (*G8*), (*G9*) and (*G10*), in the percentage of fundamental voltage, are record in Table F.2 in Appendix F. Allocation for (*G8*) solar farm is shown in Figure 7.3 below, and similar plots for (*G9*) and (*G10*) are shown in Figures F.1 and F.2 respectively in Appendix F. Their allocations are very small and considered to be well below the level that renewable generators can meet. Nevertheless, harmonic voltages at all busbars comply with planning levels. In this option, renewable generator owners would have to install additional harmonic filters at their converters. As discussed earlier, renewable generators do not contribute network absorption capability like synchronous generators. Station loads of renewable generators are very small, such that they contribute negligible impedance attenuation effects, as discussed in Chapter 4. The question is: what is the effectiveness of the new harmonic allocation method for renewable load in this option? The following analysis provides useful information for the response to this question.

- As stated in the assumptions above, before the installation of renewable plants, the remaining total network supply capacity was approximately 10%, i.e. Equivalent to 85.1 MVA, supplied by synchronous generators. In practice, it would be sufficient to supply approximately 65 MVA energy consumption loads, including 20 MVA reserved for operating margin. It means that this network still can supply up to 65 MVA passive harmonic load, which absorbs harmonic power, provides impedance attenuation and generates harmonics.

- When three renewable generators connected to this network, their combined station load, i.e. energy consumption load, would be 48.5 MVA, i.e. 5% of 970 MVA, the total generation capacity. The total station load absorbs harmonic power and provides impedance attenuation equivalent to that of 48.5 MVA passive harmonic load. However, three renewable converters, with a total combined generating capacity of 970 MVA, would generate much more harmonics than that of the 48.5 MVA passive harmonic load.

- It can be said that the new allocation method utilises all remaining harmonic absorption and impedance attenuation of the network to allocate emission rights to the new renewable generators effectively and fairly while ensuring that harmonic voltages at all busbars comply with the planning level. The only challenge is that the allocations would be very small for these renewable sources, such that they may need to install additional harmonic filters at their converters to comply. Otherwise, the network needs to be augmented to increase harmonic absorption and impedance attenuation capabilities so that more allocations can be given to the three renewable generators. Under the current Australian Electricity Rules. i.e. NER, it is highly likely that the owners of the renewable generators will have to pay for the network augmentation costs based on the principle of "do no harm" to the system.

7.3.5 Option 2 - Allocation Based on Generators' MVA Rating

In this option, it is assumed that the renewable generators generate harmonics equivalent to harmonic (non-linear) passive loads, which have the same MVA rating as the renewable generators. The new allocation method can then be applied the same way as it was for option 1, but with much larger (*Si*), e.g. 320 MVA, 525 MVA and 125 MVA for (*G8*), (*G9*) and (*G10*) respectively. It means that the remaining network absorption and impedance attenuation capability, e.g. equivalent to 65 MVA harmonic passive load, will be well below the level of harmonics allocated to the renewable generators (970MVA). Allocations to (*G8*), (*G9*) and (*G10*) are also recorded in Table F.2 in Appendix F. Allocation for (*G8*) solar farm is shown in Figure 7.3 below, and similar plots for (*G9*) and (*G10*) are shown in Figures F.1 and F.2 respectively in Appendix F. Their allocations are much higher compared to Option 1 above. As expected, harmonic voltage performance at relevant busbars exceeded the planning level as shown in Table 7.3 below. In this case, TSO would have to install harmonic filters at the applicable PCCs and pass on the additional cost to all network participants and consumers. This option would be considered as over-allocation and can be seen as unfair for existing network participants and consumers. It is neither fair for passive loads, which contribute significant harmonic energy absorption and impedance attenuation to the network but still receive the same allocation as the new renewable generators that contribute negligible effects to network harmonic absorption capabilities.

7.3.6 Comments on Allocation Options

The new allocation method was used to allocate harmonics to both options. Under the assumed condition that the network only has 10% absorption capability left, the results obtained from Option 1, i.e. allocate according to the size of renewable generator's station loads, seems to be fair and reasonable. Another option that can be considered to compare with Option 1 is to equally share the remaining absorption capability of the network across three renewable generators. It means that the remaining absorption capacity of 65 MVA, i.e. 85.1 MVA less 20.1 MVA reserved capacity for operational margin, can be shared among three renewable generators. The 85.1 MVA can be divided as 25% reserved for operating margins and the three renewable generators would receive 25% each. In other words, 10% remaining absorption capacity of the traditional network can be divided as 2.5% as the reserved capacity for operating margin, and each renewable generator would receive 2.5%. One may argue that generators G8, G9 and G10 should receive different portions relative to their generating capacity. Nevertheless, as long as the allocation does not exceed the total network absorption capability, the results would be the same as Option 1. However, allocation as per Option 1 provides a link between the remaining supply capacity and anticipated loads that will help to assess if the network can accommodate the new loads. On the other hand, Option 2 would result in a much higher allocation than what the network can absorb that the TSO needs to install harmonic filters or augment the network. As discussed in Chapter 4, installing additional harmonic filters will increase capacitance in the network that leads to higher chances of harmonic resonances and have adverse effects on harmonic voltages at busbars.

The new allocation method provides a consistent principle, which can be applied to allocate harmonics for a wide range of sources. It provides practical procedures to assess if the network can accommodate the connection of new plants or network augmentation may be required. Ultimately, once the network absorption capability is below the required level to support new connections, a range of harmonic management options needs to be considered.

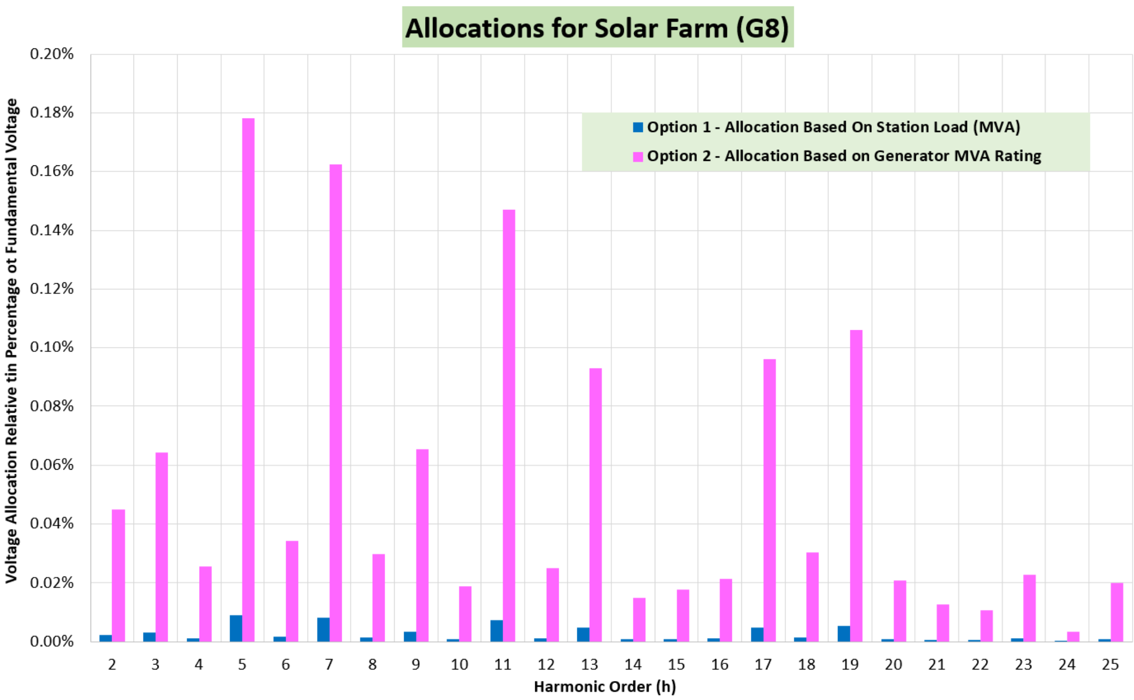


Figure 7.3 – Allocation for Solar Farm (G8)

Table 7.3 – Bus Harmonic Voltages Exceeded Planning Level as a Result of Over-Allocation based on Generators' output

h	Buses Exceeded Planning Level As a Result of Over-Allocation Based on Generators' Output						
	1	2	4	7	8	9	10
2	131%			149%	107%	129%	
3	113%			133%		119%	
4	101%			122%		110%	
12					124%		
13		114%	117%		123%		
15		124%					
16	114%	116%		119%			
17	123%	118%		127%			
20	121%	144%		125%	102%		114%
21		150%		103%			
22		104%					
23	107%			112%		147%	210%
24	137%			141%		125%	357%
25	168%			171%		317%	272%

7.3.7 Assessment of Harmonic Voltages under Different Scenarios

Based on the new harmonic allocation method for loads, renewable generators would receive very little allocations, due to their inability to contribute to network absorption capability and harmonic impedance attenuation. It is most likely that harmonic filters will be required at the PCC or built-in to the converter circuitries of renewable generators. The cost and complexities of active harmonic filters will be very significant hence can be impractical to deploy. Static harmonic filters are often used to filter certain harmonics from renewable generators. However, it will also introduce more capacitance into the network that leads to higher chances of harmonic amplifications at other busbars.

Alternatively, if harmonic allocations to renewable generators are increased beyond the level recommended by the new harmonic allocation method, harmonic voltages at busbars will certainly increase and can significantly exceed planning levels, depending on the remaining harmonic absorption and attenuation capability of the network at that time. Therefore, options to mitigate excessive harmonic voltages may be required. The following scenarios are purposely designed to illustrate different options that can be considered to help lowering harmonic voltages and reduce adverse effects from over-allocation if and when the situation eventuates as a result of high renewable penetration.

7.4 Harmonic Management Options

7.4.1 Scenario 1 – Over-Allocations to Renewable Generators at Remote Buses

It was observed that over-allocated harmonic current sources connected to remote buses increase the chances of harmonic amplification, as shown in Figure 7.4 and 7.5 below. These plots only show busbars that have harmonic voltages that exceeded planning levels. Harmonic voltages at existing busbars 1 – 7 exceeded planning levels but not as significant as at Bus 8, 9 and 10, i.e. renewable generator PCCs. The main contributing factors for high harmonic voltages are:

(i) Over-allocation leads to additional harmonic power flow in the network; coupled with

(ii) Higher network impedances at remote busbars; and

(iii) Higher chances of amplifications from long transmission lines due to additional network capacitances.

It is noted that not all busbars have harmonic voltages exceeding planning levels, e.g. Bus 3, 5 and 6. Busbar voltages that exceed planning levels, do not occur at every harmonic, e.g. 5th to 12th harmonic orders for Bus 1, 2, 4 and 7 and a similar trend for Bus 8, 9 and 10. As discussed in Chapter 4, transmission network impedances are very complex, predominantly due to transmission line characteristics, less so with large capacitor banks in meshed networks, and the mix of different network elements in different network scenarios. Each network scenario results in unique impedance characteristics, which is not practical to simplify or predict, but complete frequency scanning procedures should be applied to every possible network scenario to calculate *Influence Coefficients* and work out harmonic allocations under different network scenarios. Chapter 8 will look further into these challenges and recommend suitable methodologies to allocate harmonics to suit different load profiles.

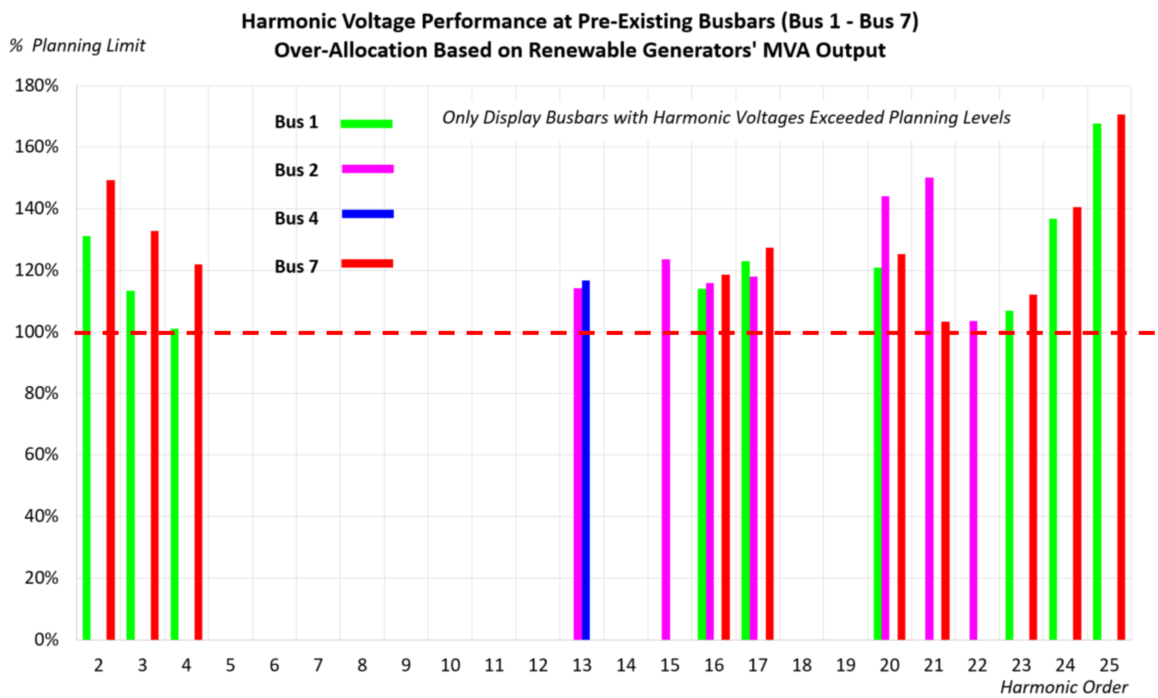


Figure 7.4 – Harmonic Voltage Performance at Pre-Existing Busbar – Over-Allocation Based on Renewable Generators' MVA Output

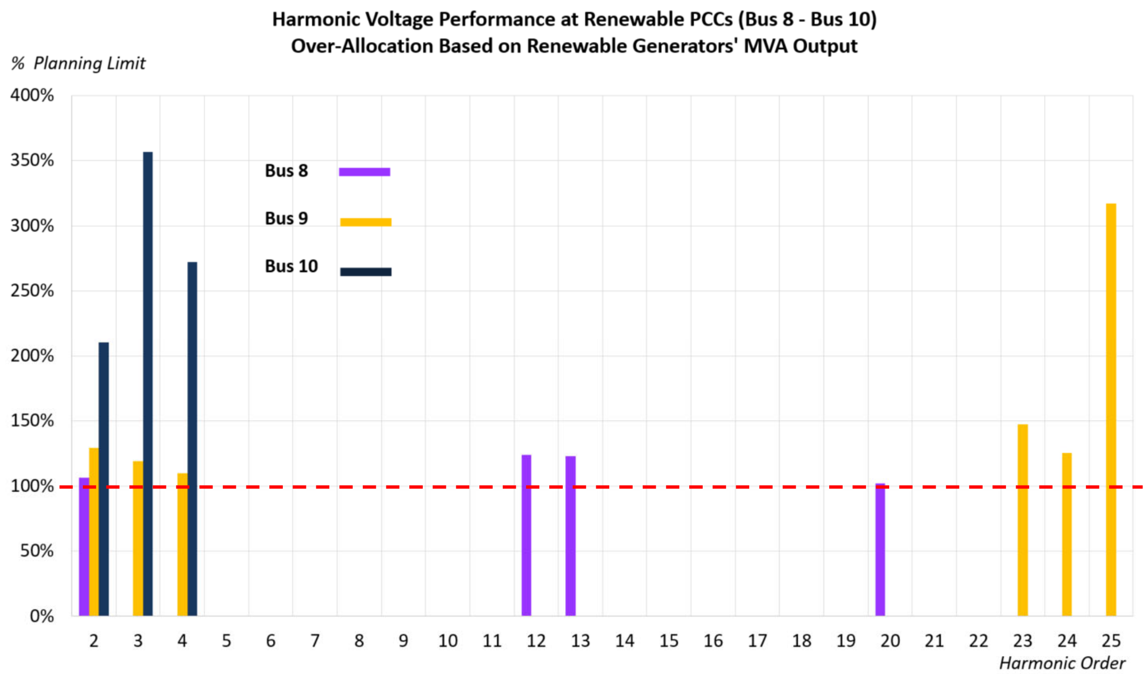


Figure 7.5 – Harmonic Voltage Performance at New Renewable PCCs – Over-Allocation Based on Renewable Generators' MVA Output

7.4.2 Scenario 2 – Over-Allocations to Renewable Generators at Existing Buses

In this scenario, renewable generators are connected to local buses, i.e. *G8*, *G9* and *G10* connected to Bus 5, 3 and 6 respectively. Therefore, Lines 9, 11 and 12 will not be required and the additional line capacitances between the existing network and new renewable generator buses are removed from the network, such that chances of harmonic amplification are reduced and harmonic voltages shown in Figure 7.6 are significantly lower than voltages shown in Figures 7.4 and 7.5 above. It means that renewable generators would be able to receive higher allocations if they are connected to existing busbars and at the same time void the additional cost of new transmission lines and remote substations. These advantages can be considered against the cost of, and the suitability of, land use required for renewable generators. Further discussion on this topic and similar arrangement, e.g. renewable zones, will be examined in Chapter 8.

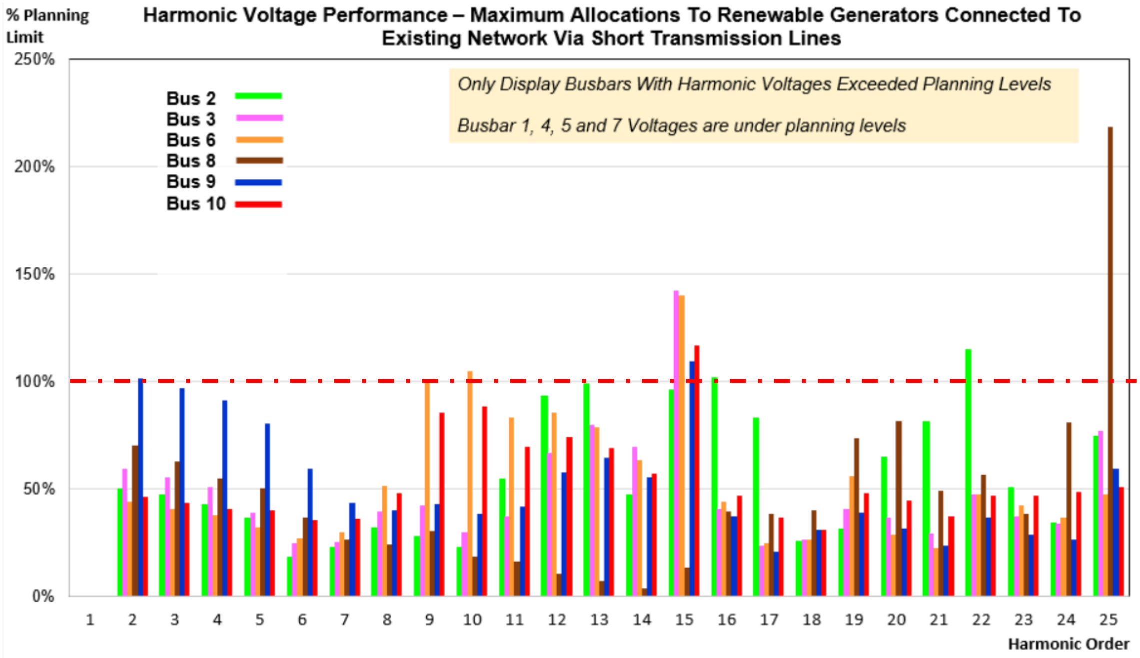


Figure 7.6 – Harmonic Voltage Performance – Renewable Generators Connected to Existing Busbars

7.4.3 Scenario 3 – Effects of Consumer Loads at Renewable Generators' PCCs

In this scenario, renewable generators are connected to remote buses via long transmission lines as per Scenario 1. Additional consumer loads 300 MVA, 500 MVA and 100 MVA are connected to renewable generator buses 8, 9 and 10 respectively. It is intended that these loads match the generating output of renewable generators, such that most of the energy generated from renewable generators directly supply loads connected to the same PCC. To focus on the main points, it is assumed that these loads are predominantly linear, hence they generate an insignificant amount of harmonics, which can be omitted in this scenario. These linear loads are modelled as CIGRE linear load model described in the CIGRE guideline [22]. Otherwise, in practice, the total allocation at each PCC would have to be shared between the renewable generator and consumer loads at that PCC. In any case, it was observed that harmonic voltages were significantly reduced as shown in Figure 7.7. This result indicated that loads at renewable generator PCCs can provide very effective harmonic impedance attenuation effects and harmonic power absorption effects right at the source, hence reduce the chances of harmonics propagation to other buses. The more harmonic power absorbed closer to the source, the less harmonic power flows to other parts of the network. The more impedance attenuation, the less chances of amplifications to remote buses. However, if these loads are connected to Bus 5, 3 and 6 instead of renewable generator PCCs (Buses 8, 9 and 10), harmonic absorption effects are much less effective due to the additional transmission lines and capacitances between loads and renewable harmonic sources.

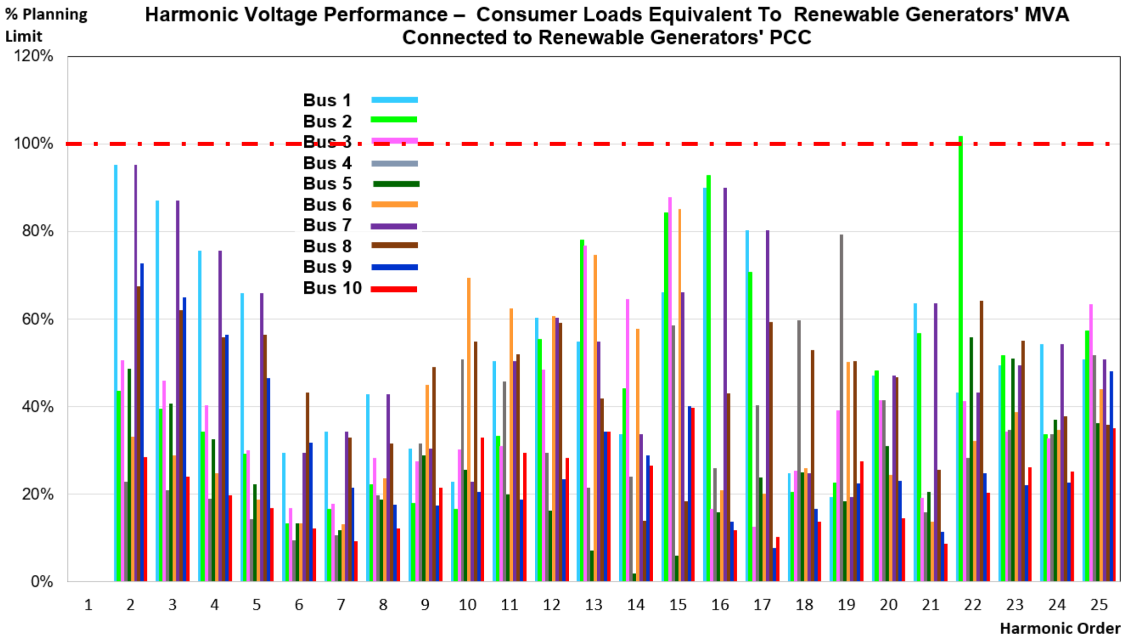


Figure 7.7 – Harmonic Voltage Performance – Presumably Consumer Loads Connected to Renewable Generators' PCCs

Harmonic allocations at these renewable PCCs (global contribution at PCC) can be increased significantly as shown in Figure 7.8 if these loads are installed at renewable PCCs. For comparison purpose, Figure 7.8 shows differences in harmonic allocations between two cases – with and without energy consumption loads connected to renewable PCCs – both result in all busbar voltages complying with planning levels. It can be interpreted that large consumer loads installed close to renewable harmonic sources, e.g. connect to renewable PCCs, increases harmonic power absorption capability and impedance attenuation at these connection points, such that renewable generators can receive much higher allocations. It also means that harmonic allocation to wind or solar plant can be increased significantly if they are connected to a PCC that has, or is being closer to, large commercial or industrial loads, e.g. processing plant, refinery or mines.

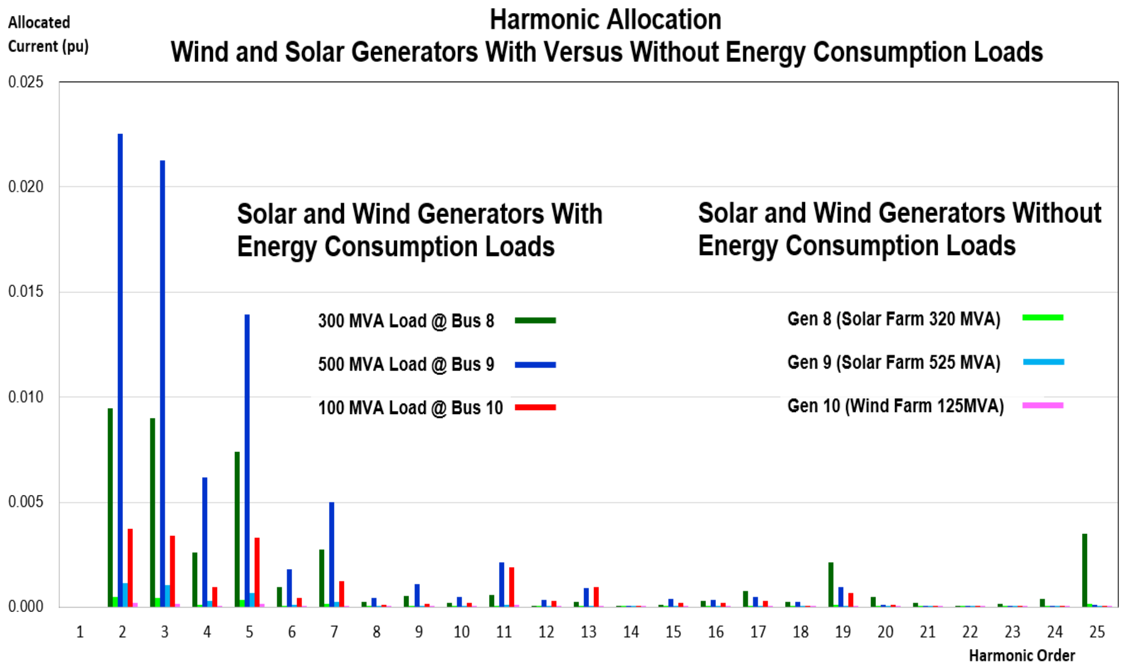


Figure 7.8 – Harmonic Allocation – Renewable Generators With and Without Energy Consumption Loads

7.4.4 Scenario 4 – Synchronous Condensers at Renewable Generators' PCC

Synchronous condensers are installed at Bus 8, 9 and 10 where renewable generators are connected. Harmonic voltages are reduced as shown in Figure 7.9. Similar to the loads' ability to absorb harmonics, synchronous condensers connected directly to renewable PCCs can also provide very effective harmonic absorption. If these synchronous condensers are connected to Bus 5, 3 and 6 instead of renewable generator PCCs (Bus 8, 9 and 10), harmonic absorption is less effective. Therefore, from a harmonic point of view, it is best to install synchronous condensers as close to harmonic sources as possible or vice versa.

It is noted that both energy consumption loads (Scenario 3) and Synchronous Condensers (Scenario 4) provide effective harmonic absorption effects that result in a very significant reduction of harmonic voltages at all buses as shown in Figures 7.7 and 7.9. However, harmonic voltage profiles between these figures are somewhat different due to the mix between their characteristic impedances and the network impedances as discussed in Chapter 4. The synchronous condensers reduce voltages at lower frequencies more effectively than at mid-frequency range, e.g. 10th to 22nd harmonics. Loads, modelled as CIGRE load, appear to reduce harmonic voltages more at higher frequencies and around the 7th harmonic order. These profiles are subject to changes in network scenarios and locations of plants.

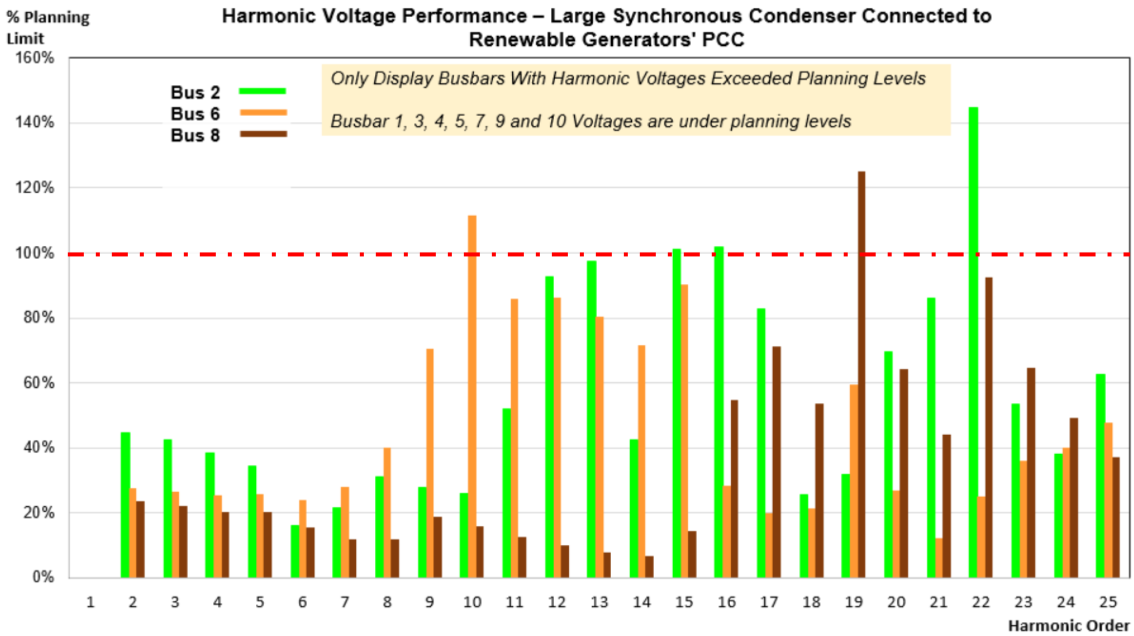


Figure 7.9 – Harmonic Voltage Performance – Synchronous Condensers Connected to Renewable Generators' PCCs

7.4.5 Scenario 5 – Retirement of a Large Synchronous Generator

Retirement or disconnection of the synchronous generator (*G3*) at Bus 3 would cause background harmonic voltages to increase beyond planning levels at a number of buses. Especially, increases of low order harmonics such as 2*nd* order harmonics are serious concerns, due to loss of harmonic absorption from synchronous generators, as shown in Figure 7.10. Harmonic voltages at the low-frequency range increased significantly compared to voltages show in Figure 7.9 above, which has an additional synchronous machine installed. High-frequency harmonics at Buses 2, 9 and 10 also increase substantially as their network impedances increase.

This scenario is very likely for future networks with higher renewable penetration as conventional thermal generators may not be financially viable to compete with renewable generation sources. Therefore, it is important to recognise the important roles of conventional synchronous generators in the network and perhaps an amendment to the electricity rules would be necessary to financially support synchronous generators and prevent/delay their pre-mature retirement dates. Chapter 8 will recommend options to help to prolong or maintaining harmonic absorption capability from synchronous machines.

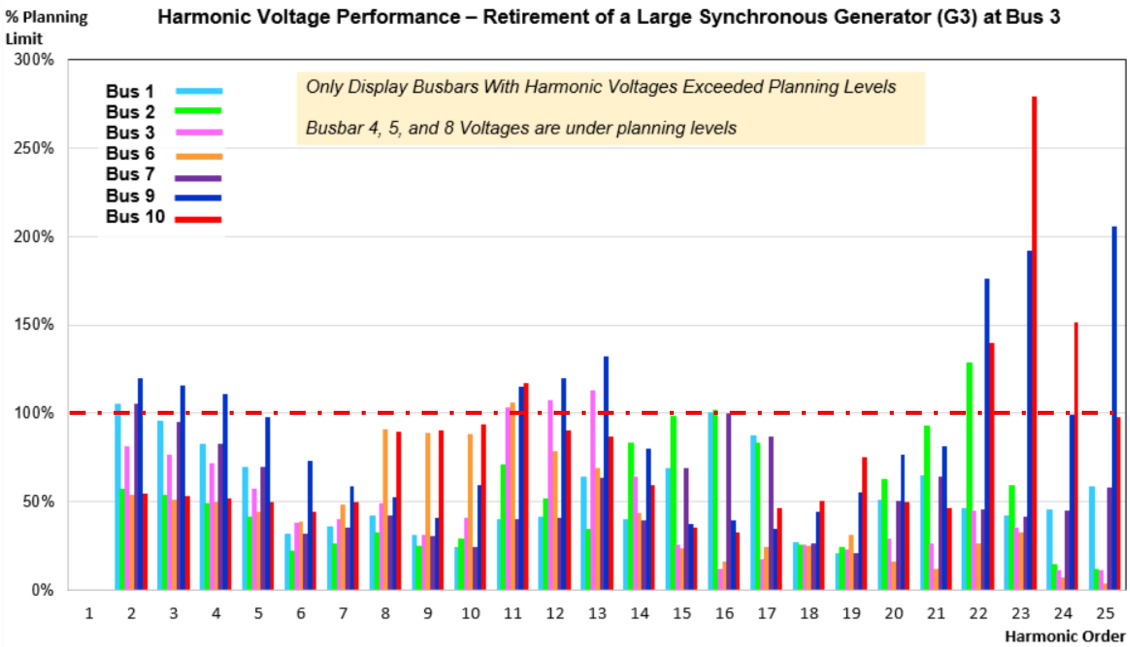


Figure 7.10 – Harmonic Voltage Performance – Retirement of a Large Synchronous Generator (G3) At Bus 3

7.4.6 Scenario 6 – Harmonic Filters at Renewable Generators' PCC

When harmonic voltages at a PCC exceed planning levels, harmonic filters are often required to mitigate. In this scenario, a passive harmonic filter was installed at Bus 10 which leads to harmonic currents reducing significantly. The resulting harmonic voltages at other buses in the system are shown in Figure 7.11 for those that exceed planning levels. A "type C" passive harmonic filter, which has an additional resistor as described in the literature review, was also modelled and installed at Bus 10 to filter high harmonic currents and provide additional impedance attenuation effects at the renewable generators PCC. It was found that the "type C" filter, which introduces extra resistance in the circuitry, provides only additional absorption (and filtering effects) at the local PCC, i.e. Bus 10, otherwise, it is very similar to other passive filters that increase capacitance in the network and higher chances of harmonic resonances for both local and remote buses. Both harmonic filtering and impedance attenuation effects are effective around the tuned frequency of the filter, i.e. the series resonance point of the filter. Impedances at frequencies further away from the filter's tuned frequency can often be amplified much higher due to higher chances of parallel resonances between the filter and network inductive elements at those frequencies. For this reason, there is no evidence to support that detuned voltage support capacitor banks will have positive effects on reducing voltages across all harmonics as discussed in Chapter 4. Results obtained from case studies conducted in Chapter 4 showed that if all voltage support capacitor banks are detuned at a particular frequency, e.g. 2.8^{th} (140 Hz in 50 Hz system), harmonic impedances around 140 Hz will be substantially reduced due to series resonant impedances connected as shunt elements at applicable busbars. However, these low frequency detuned capacitor banks can also form parallel resonant circuits with other capacitive network elements and increase resonant impedances at frequencies above the tuned / detuned frequency as discussed in Chapter 4. A general rule of thumb is that the more shunt capacitance added to the network the higher chances of parallel resonances will be.

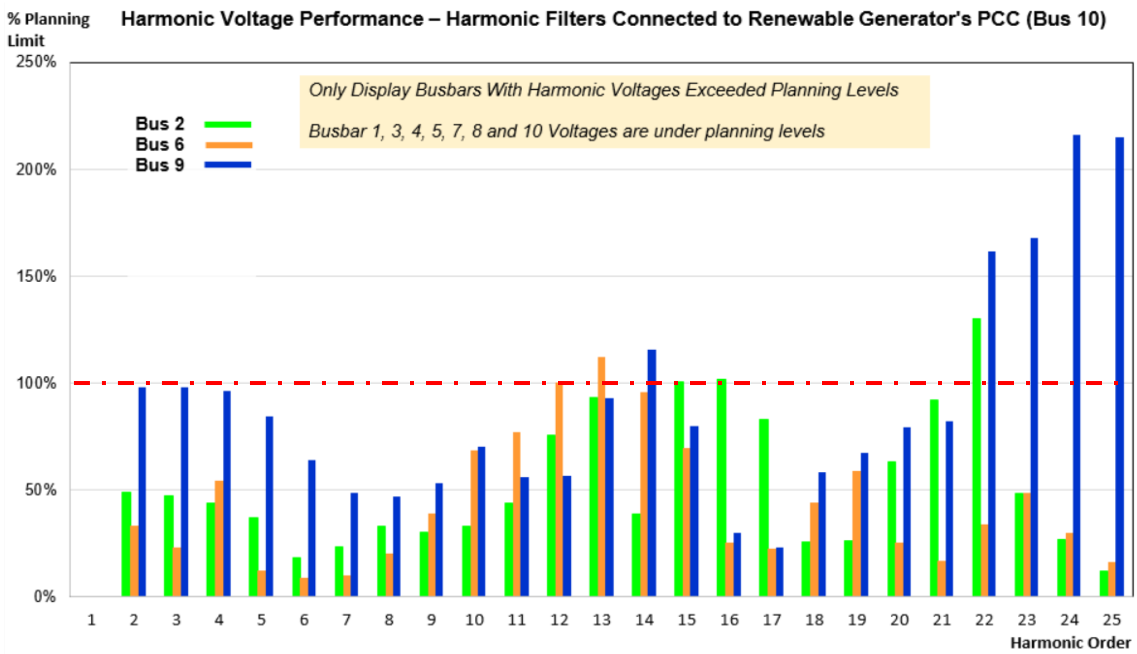


Figure 7.11 – Harmonic Voltage Performance – Harmonic Filters Connected to Renewable Generator's PCC (Bus 10)

7.5 Considerations for High Renewable Penetration Network

The purpose of this case study was to apply the new method to allocate harmonics to renewable generators connected to a transmission network. As discussed above, the new methodology would only allow very small allocations to renewable generators based on fair and equitable principles. Unlike passive harmonic producing (non-linear) loads, renewable generators offer very small harmonic power absorption and impedance attenuation capabilities to the network. Renewable generators rely on the remaining network absorption and impedance attenuation capabilities, which predominantly are contributed by other network participants, including synchronous generators and energy consumption loads. In this case study, it was identified that, before the installation of renewable generators, the remaining network absorption capability was very low, approximately 10%, hence renewable generators should only be allocated with a very small allocation as discussed. It is considered that the new harmonic allocation method is fair, consistent, flexible and suitable for solar and wind generators. Only very small allocations would be allocated to renewable generators, hence it is likely that the owners of renewable generators need to install additional filters to lower their emissions. Alternatively, renewable generators may be given more allocations if they contribute financially to the network solutions to increase network absorption and attenuation capability. This topic will be further discussed in Chapter 8.

The case study conducted in this Chapter has not considered the reduction of harmonic allocations to new passive loads as a means of giving something useful to renewable generation. The reason is that the new harmonic allocation method, derived in Chapter 5, aims to maximise allocations to network participants, who can demonstrate firm commitments to participate in the network, whether as a passive or active load. Its principle is to minimise dependencies on the uncertainties of future network scenarios, which can be highly unreliable. As discussed in previous chapters, if an unplanned passive or active load needs to connect to the network at a particular time that the network absorption capability is insufficient, then network augmentation may not be avoided.

This research project provides a limited number of cases to demonstrate different possible options to manage harmonics in transmission systems. In practice, many more allocation scenarios for renewable generators can be examined depending on the specific needs and circumstances of individual networks. The case study has not examined a scenario where a passive load, e.g. a distribution load, and an active load, e.g. a solar farm, are to be connected to a common PCC. In this scenario, a lower weighting can be applied to the active load and a higher weighting for a passive load. This approach is to do something proactively for renewables without being too threatening to other passive loads. It may give a decreased weighting to later renewable generation installations since what is certain now deserves a better allowance than the later uncertain possibilities. This approach would be considered as "pro-renewable" and may be challenged based on fairness and equality measures. However, the TSO has the ultimate privilege and responsibility to allocate harmonics to all transmission network participants. It is important that pre-existing network participants are not adversely affected by new loads, concerning both technical performance and cost. The terms fairness and equality should be interpreted for loads installed under the same network scenario.

Higher penetration of renewable generators in the network will eventually require additional solutions to help manage harmonics in the system. Once the network absorption capacities are fully utilised, additional measures such as filters or synchronous condensers will likely be required for network support. This case study also explored practical options to improve network harmonic absorption and impedance attenuation capabilities to potentially allow higher allocation to renewable generators. Unfortunately, these options will likely result in additional costs that should be factored in the Connection and Access Agreements (C&AAs) with renewable plant owners. Several practical options can be considered to increase harmonic allocations to renewable generators.

7.5.1 Increase Harmonic Absorption and Impedance Attenuation Effects

Figure 7.7 of Scenario 3 emphasised that passive loads are critical for harmonic absorption and impedance attenuation effects, which would lessen as the electrical distance between harmonic sources and passive loads increases. This implies that network reconfiguration, e.g. splitting load buses due to maintenance or reconfiguration to accommodate project work, can significantly reduce network harmonic absorption capability. Thus, load location and balance between supply power and loads are very important to harmonic allocations. While a TSO will, in practice, have little control over the physical location of either load or generation plant, they will influence the electrical location for less remote installations.

7.5.2 Install Synchronous Condensers

Figure 7.9 of Scenario 4 showed that synchronous condensers could increase network harmonic absorption capability. Similar to loads, as synchronous condensers are installed further away from harmonic sources, their absorption effects will lessen. Therefore, the most effective location for synchronous condensers to maximize harmonic absorption capability is at renewable generator PCCs.

Under some unique network scenarios, interactions between reactance of synchronous condensers, transformers, capacitances of transmission lines, capacitor banks or SVCs could also result in resonances at some frequencies. These can cause increases or decreases of harmonic voltages at remote buses. Therefore, checking for increases of harmonics at all buses due to resonances is an important step in the allocation process.

7.5.3 Postpone Retirement of Large Synchronous Generators

As more solar and wind plants are connected to the power system, there are increasing chances of synchronous generators retiring prematurely. In Scenario 5, an existing synchronous generator, *G3*, was disconnected from Bus 3. Figure 7.10 showed that background harmonics rose sharply as a result, especially at the remote buses, e.g. Bus 9 and 10, connected to the system via long transmission lines and effectively decoupled from harmonic absorption sources. A major contributing factor that leads to the early retirement of synchronous generators connected to the network is financial competitiveness. Therefore, it is in the interest of all network participants, and especially renewable generator owners, that large synchronous generators should be incentivised with the appropriate network support contracts to remain connected to support the network as long as possible. This poses another question as to who will be responsible for additional cost to support these contracts. Alternatively, additional cost may be required to mitigate the increase of background harmonics following the retirement of synchronous generators.

7.5.4 Install Harmonic Filters

Harmonic filters are often used to filter particular harmonic currents. Passive filters generally have good filtering effects at local buses where harmonic current sources are connected. However, they are sensitive to variations of network impedances, network topologies and frequencies. Active harmonic filters, which are effective in cancelling specific harmonics, are generally not sensitive to network elements, however, they are very expensive and complex compared to passive filters. Therefore, this thesis considered only passive filters. Scenario 6 included passive harmonic filters installed at Bus 10, which effectively reduced harmonic currents locally, as shown in Figure 7.11. However, it also increased harmonics at Bus 9 due to resonances between the network and its capacitances. Recently, "type C" passive harmonic filters have also been used to filter harmonics as well as to increase harmonic absorption and impedance attenuation effects at renewable generator PCCs. However, these effects are limited to local PCCs only. Overall, passive filters can reduce harmonics, near its tuned frequency, at a local bus, but can also increase the chances of parallel resonances at frequencies further away from its tuned frequency and at other remote buses. Therefore, checking for increases of background harmonics across the entire harmonic spectrum and at all buses in the network is essential whenever passive filters or capacitor banks (detuned or non-detuned) are installed.

7.6 Summary

This chapter examined the suitability of the new harmonic allocation methodology for renewable generators, namely solar and wind plants. While conventional synchronous generators and energy consumption loads contribute significantly to the network harmonic absorption capability and attenuation effects, renewable generators generally do not. Based on fair, equitable allocation principles, the new harmonic allocation method would only allow a very small harmonic emission right, e.g. up to a maximum of 5% of planning level, to wind and solar plants. The higher allocation may be achieved if the network still has significant absorption and impedance attenuation capacity left. This can be assessed at the discretion of TSOs. However, this would be treated as an exception to the recommended allocation methodology and alternative network access and connection charges may be required to fund other supporting solutions potentially required to reinforce the network's capability.

This chapter also examined the principles of the new harmonic allocation methodology through a harmonic allocation case study for renewable generators. Overall, the principles of fair and equitable allocation to harmonic loads also agree with those of existing harmonic standards. It also highlighted the significance of harmonic absorption capability and impedance attenuation effects from synchronous machines, energy consumption loads and associated network infrastructures. Unique harmonic characteristic of renewable generators, which effectively do not contribute to the network absorption capability, has also been examined. The roles and responsibilities, with regards to harmonic allocations, of both network owners and renewable proponents during the connection proposal phase were clarified.

According to the new allocation method, renewable generators would receive very small allocations that may require generator owners to install harmonic filters to comply. The effects of high harmonic voltages at busbars exceeding planning levels due to over-allocation to renewables were also examined under a range of scenarios, which include: (i) renewable generators connected to remote buses via long transmission lines; (ii) renewable generators connected to existing buses (i.e. without long transmission lines); (iii) large loads connected to the same PCC as the renewable generators; (iv) synchronous condensers connected to renewable generators' PCCs; (v) early retirement of existing synchronous generators; (vi) harmonic filters connected to renewable generators PCCs. Practical solution options to improve harmonic management for transmission networks with high penetration of renewable generators were recommended.

Overall, it can be summarised that the new harmonic allocation methodology is fair, equitable, consistent, flexible and suitable for solar and wind generators. The main challenge is that when the network absorption capability and impedance attenuation effects are used up, additional network solutions will eventually be required. Passive harmonic filters are technically practical and economical options, however, be mindful that they will also introduce more capacitance in the network that increases the chances of network resonances and remote amplifications. An update of the Australian NER is recommended to provide appropriate incentives to TSOs to maintain and procure additional network harmonic absorption and impedance attenuation capabilities to reinforce the network and allow higher penetration of renewable generators that benefit all network participants and consumers.

8 Strategic Harmonic Planning and Management Framework for Transmission Systems

8.1 Introduction

This chapter proposes the harmonic planning and management framework to support the practical application of the new allocation method, which was developed in Chapter 5 and based on the IEC report. It includes: (i) harmonic planning, allocation workflow and procedures; (ii) a new methodology to select the most relevant network scenarios, based on both Voltage Total Harmonic Distortion (THD_V) and harmonic profile criteria, to suit different types of harmonic sources under a wide range of network scenarios; and (iii) recommended harmonic planning for renewable zones.

Network configurations are often augmented or reconfigured over time to meet network participants' needs. Changes in network configuration can lead to large variations of harmonic impedances over time. Chapter 4 identified that network impedances obtained from 22 network scenarios of a realistic case study transmission network could vary as much as 97% at specific harmonics. Large variations of harmonic impedances present practical challenges to harmonic allocation methods that rely on accurate determination of harmonic impedances, such as the IEC method and the new allocation method. Transmission network scenarios may range from a few hundred to a few thousand cases. Harmonic frequency scanning for all possible network scenarios can be achieved with the aid of modern computers and software. However, not all network scenarios are required, depending on their likelihood and implication on harmonic allocation results. Therefore, additional processes and selection criteria may be adopted to select only likely "network scenarios", e.g. > 5% of probability to eventuate. These criteria are helpful to reduce the large number of network scenarios required, but not essentially required as computer software should be able to handle a very large network without issues. However, the most important point is that an optimisation process must be required to select only one final set of allocations, from a few thousand sets, that best matches the characteristics of harmonic sources.

The proposed strategic planning framework for harmonic management includes practical applications of the new allocation method and is designed to help TSOs strategically and proactively manage harmonics in their network in a cost-effective manner. This framework comprises of: (i) section 8.2 – design a strategic harmonic management workflow, including relevant principles, allocation processes, current and voltage allocations to suit different types of loads in transmission systems; (ii) section 8.3 – propose an optimised harmonic allocation methodology to select the most suitable allocations, for different types of load, from a very large number of network scenarios; and (iii) section 8.4 – put forward a number of proactive and strategic harmonic planning recommendations for renewable zones and an introduction of Power Quality Auxiliary Services (PQAS).

8.2 Proposed Strategic Harmonic Management Workflow

8.2.1 Principles

Once harmonics are allocated to loads, they cannot be changed without a variation to the Connection and Access Agreement (C&AA). In most cases, it is impractical to change harmonic allocations after plants have been built and commercially connected to the network. Therefore, as long as loads comply with their allocations, TSOs are solely responsible for managing and mitigating any harmonic issues in their network. TSOs would need relevant guidance on harmonic planning and methodical processes, including any relevant measurements, to manage harmonics in their network and minimise unintended outcomes.

As discussed in previous chapters, most utilities still reactively manage harmonics. A reasonable explanation for this approach could be that harmonics in the past did not cause many issues due to very few non-linear loads and the network has high absorption capability. This condition has already changed for networks that have higher penetrations of power-electronic devices, including both generators and loads, which will inevitably lead to more harmonic issues. Unfortunately, without procedures in place and a framework to reinforce, practical harmonic management can be very challenging. The following principles are proposed to be included in the harmonic management framework to support the practical application of the new harmonic allocation method.

- Proportional MVA Power Principle: Harmonic allocation to major loads in transmission systems should be proportional to the ratio between the MVA power of the connecting load (S_i) and the total supply capacity (S_{tS}) of PCCs as per (8.1). This principle is consistent with the new allocation methodology as well as the IEC Report. It is fair and equitable because larger loads contribute more to connection charges and network costs.

$$E_{Uhi} \propto \frac{S_i}{S_{tS}} \tag{8.1}$$

- Non-Discriminatory Network Access: TSO must ensure that non-discriminatory network access is available to all network proponents and market participants. This may lead to a scenario that multiple loads or renewable generators connect to the same network element (e.g. a multi-Tee feeder) and each shares a fair portion of the absorption capacity at the common connection point. TSO must ensure that the network is configured in such a manner that accommodate these scenarios and the supply capacity at the connection point satisfy (8.2) below:

$$S_{tS\ Bus\ m} \geq \sum_{i=1}^{n} S_{i\ @\ Bus\ m} + Mandaroty\ Reserved\ Operating\ Margin \tag{8.2}$$

S_{tS} Bus m: Total Supply Capacity at Bus m

S_i: individual loads connect to Bus m

Mandatory Reserved Operating Margin is required to ensure that the network still fully functions under the recommended contingency network configuration, e.g. *N-1*.

- Harmonic global contributions at PCCs must be maximised, through effective utilisation of network absorption capability, such that TSO's planners need to strategically optimise network configurations to allow maximum supply capacity at substations or network areas that are strategically planned for more loads or hosting more renewable generators.

- First-Come First-Served Basis: TSO needs to maintain the record of harmonic allocations given to harmonic sources to date, and to ensure that the *total supply capacity* (S_{tS}) is planned in such a manner that it will not adversely affect existing network participants e.g. loads or generators. An example below is used to demonstrate the application of this principle. Furthermore, it is highly recommended that TSOs update and publish the network absorption capability and available supply capacity, which is also often referred to as "*supply headroom*", at all PCCs.

- Higher penetration of renewable generators, which have large variations in harmonic characteristics, will lead to more dynamic and complex harmonic profiles. These are much more difficult to model and manage. Some plants may have elevated level of low order harmonics, e.g. 5th or 7th harmonics, while others may have elevated emissions at higher-order harmonics. Therefore, TSO should look for practical options, e.g. combined application of harmonic filters, transformers and synchronous condensers, to flatten (create a more even) harmonic profile within a network area or across the entire network.

- Solar and wind plants in transmission system are often made up of a number of MV inverters connected in series and parallel arrangement via cables and transformers. To date, there are no available studies that comprehensively examine if and how diversity factors should be applied to harmonics from these inverters that are summated at a transmission PCC. It is noted that some utilities and consulting engineers may have applied the IEC report's alpha constants to the summation of MV harmonic current sources. This approach may, or may not, provide desirable outcomes as there is no supporting evidence available at this point. The total fundamental currents at the PCC should be the arithmetic sum of individual sources that made up the plant. Therefore, TSO could just arithmetically summate individual MV harmonic currents at the PCC, ignore MV cables and transformers. In the absence of detailed studies, this would be considered as the worst scenario but based on a reasonable assumption.

8.2.2 Strategic Network Area Planning

Strategic harmonic planning is about actively identifying opportunities and methodologies to improve harmonic management by minimising chances of unintended harmonic issues. However, many utilities only consider harmonic assessment after other planning processes. This causes a number of challenges that are often difficult to resolve at a late stage. Sometimes harmonic issues are the unintended consequences of previous planning decisions that were made without considerations for harmonics.

The new harmonic allocation methodology maximises the *global harmonic emissions* at relevant PCCs. Greater benefits could be achieved when the new allocation method is applied in conjunction with strategic network planning practices that allow extra *supply capacities* to be redirected from low to high growth network areas. This can be achieved through network reconfiguration.

To avoid unnecessary complications as discussed in Chapters 2 and 3, it is proposed that the planning and assessment of harmonics should focus on the supply capacity of (S_{tS}) at every busbar according to (8.3), which is repeated from equation (5.2). Harmonic planning should be integrated into TSO's 5 – 10 year network development plan, or an equivalent Strategic Asset Management Plan (SAMP). The plan would also include details of network reconfigurations, augmentation, mothballing, or retirement of aging network elements with low utilization and high long-run cost. The aim is to deliver favourable network scenarios with a high concentration of loads and supply capacity at strategic substations (PCCs) or network areas.

$$S_{tSm} = \left[\sum_{i=1}^{n} S_{Gen\_i} + \sum_{x=1}^{n} S_{Import\_Power\_x}\right] - \left[\sum_{j=1}^{n} S_{Existing\_Loads\_j} + \sum_{y=1}^{n} S_{Export\_Power\_y}\right] \quad (8.3)$$

Assessment of the total supply capacity (S_{tS}) must ensure that any changes to (S_{tS}) in the future due to changes of network scenarios, e.g. network reconfigurations and network augmentations, will not cause any adverse effects to existing network participants. In practical terms, it means that once (S_{tS}) is planned for a connection point, network planners must ensure that all existing network participants will not be negatively impacted by any future scenarios.

Large generators and load centres are often not close to each other. Generally, generators are installed in remote locations, where land cost is low. On the other hand, load centres are often associated with high-density population areas, except mining or smelter loads, and the transmission system connects generators to load centres. From harmonic perspectives, this arrangement has worked very well over many decades. There was an abundance of network harmonic absorption capability from synchronous generators. When a large number of renewable generators are connected to dedicated network areas, often referred to as "renewable zones" in the transmission system, significant harmonic absorption and attenuation will be required to accommodate a large influx of harmonics in a concentrated area. In particular, renewable zones for large wind and solar farms are often located in remote areas, which are far from existing load centres or synchronous generator areas, due to low land cost. A high concentration of harmonic sources from new renewable zones is often connected to the transmission system via long transmission lines that increase the chances of resonance, as evidenced in Chapter 7. Furthermore, the situation may get worse if renewable generators are given very low harmonic allocation when the remaining network absorption capability is low. In this scenario, renewable generators have to install passive harmonic filters to filter some particular harmonics from the plants. However, it also introduces additional capacitance to the network that in turn increase chances of resonances and remote amplifications as discussed in Chapters 4 and 7. Therefore, if more renewable generators are forced to install more passive harmonic filters to comply with a very small allocation, the network will experience higher chances of resonances, due to excessive capacitances in the network, and negatively affect harmonic voltage performance at other buses. Effectively, the issues are shifted from one network area to another.

Alternatively, Area Network Planning for renewable zone would require additional network absorption capability to accommodate a high concentration of renewable harmonic sources and minimise the use of passive harmonic filters to a minimum. It is proposed that TSO invest in synchronous condensers (synchronous rotating machine) to be connected within the renewable zone and distribute the costs to all renewable generators within the zone via the Connection and Access Agreement (C&AAs).

8.2.3 Harmonic Allocation Process

Harmonic sources connected to the transmission network include distribution loads at bulk supply points, large industrial plants, SVCs, STATCOMs, HVDCs, etc. Harmonic emissions are allocated to network participants at PCCs. Therefore, in principle, TSO does not need to be concerned about changes in plants' configurations in the future that can affect harmonic compliance. The allocation process is proposed to ensure that harmonics are allocated taking into account relevant parameters and configurations of plants that form part of the C&AA, i.e. the plant configuration is contractually bound. The processes are proposed as follows:

- The proponent requests for network connection with relevant preliminary plant configurations, e.g. anticipated MVA rating, voltage level and type of plants to be connected. Based on the connection enquiry information, TSO provides "preliminary" allocations, as part of the response to the connection enquiry.

- The proponent proceeds to the iterative design of their plants and validates if they will be able to comply with the emission limits. If the plant can meet harmonic requirements, then the owner will proceed to finalise the design and configuration and provide an updated configuration to TSO. Otherwise, one of the three options below may need to occur before the finalisation of the C&AA:

  (i) Plant configuration and design may need to be modified to comply with the allocations or,

  (ii) TSO and plant owners need to negotiate and agree on additional harmonic management options as identified in Chapter 7, e.g. network augmentation to increase network absorption capability or,

  (iii) TSO accepts higher emission levels on a conditional basis as per Stage 3, section 9.3 of the IEC report method.

- The proponent provides final design ratings and parameters of the plant to TSO for finalising the C&AA contract document. TSO will use the plant's parameters to validate its harmonic performance against the existing network and to ensure that existing network participants will not be adversely affected. Negotiation would continue until both TSOs and proponents can reach the final agreement. The proposed allocation flowchart is illustrated in Figure 8.1 below.

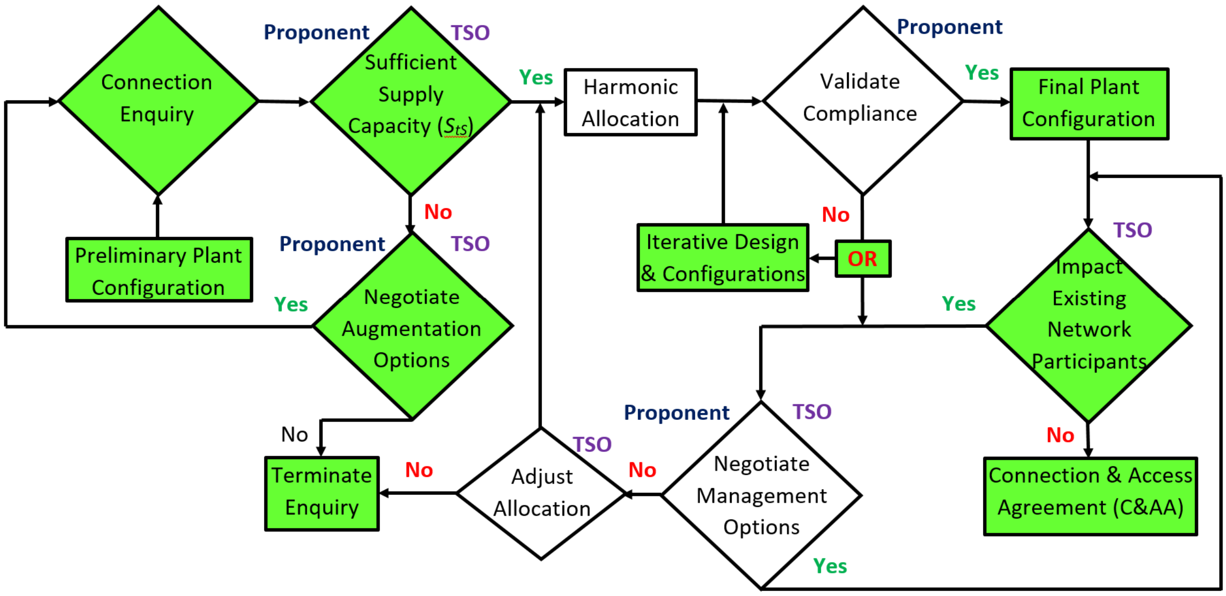


Figure 8.1 – Proposed Connection Enquiry and Allocation Flow Chart for the New Allocation Method

The main purpose of this flow chart is to support the practical application of the new allocation method derived in Chapter 5. It aims at addressing harmonic allocations as integral planning tasks of any new connection enquiries. It has four (4) tasks, uncoloured labels, that are compatible with the "Figure 5 – Diagram of evaluation procedure at MV", which focuses on the three (3) stage harmonic evaluation procedures of the IEC technical report [10]. All other tasks, highlighted in green, are proposed in this chapter to holistically cover the necessary actions required to plan and assess harmonic allocations for new connections. In addition, this flow chart also clarifies roles and responsibilities between TSO and proponents.

8.2.4 Current (E_{Ihi}) and Voltage (E_{Uhi}) Allocations

The new allocation method provides flexibility and options to allocate harmonics based on currents and/or voltages. In practice, network harmonic impedance at PCCs can vary significantly due to changes of, topologies on the transmission network side or, elements on the load side, of the PCC. Changes in network configuration on the transmission network side are highly likely over time. Distribution loads at bulk supply points can also change significantly over time, e.g. they may start from very small when first connected and gradually expand over time. On the other hand, configurations of SVC, STATCOM, HVDC, renewable generators and large industrial loads, e.g. metallurgical refineries, directly connected to the transmission system would be less likely to change after commissioning. Allocation in current or voltage terms are the same as they are proportional to the load (S_i) relative to the maximum allowable global contribution at Bus m (G_{hm}). However, harmonic allocation may be better expressed in currents or voltages to suit different types of loads, taking into account changes of network or load configurations over the lifespan of the C&AA. For example: if an allocation is given in currents (E_{Ihi}) to a distribution load at the bulk supply point, configurations of distribution loads are likely to change over time and affect voltage compliance at PCC even though its current source still complies with the original allocation (E_{Ihi}). It means that the transmission utility will be responsible for voltage violation at PCC due to changes of distribution loads that it has no visibility nor control. However, if the allocation is provided in voltage (E_{Uhi}), then the distribution load owner will be responsible for any voltage violation due to changes in their load configurations that were not included in the C&AA. The following allocations are recommended.

Table 8.1 – Recommended Voltage (E_{Uhi}) and Current (E_{Ihi}) Allocations for Different Types of Loads

Plants/Loads' Type	Recommended Allocation	Reasons	Joint Planning Coordination Meeting
Plants: SVC, STATCOM, Solar, Wind, Battery Storage, HVDC and Thyristor Control plants, mining loads, Industrial loads, e.g. metallurgical refineries.	Current	• Loads' configurations mostly remain the same after the connection is made; • Harmonic current sources generally do not change after commissioned; • Changes in harmonic impedance only depend on the network's configurations.	Generally not required.
Loads: Distribution loads at the bulk supply point.	Voltage	• Loads' configurations often change over time; • Harmonic current sources may also change over time; • Changes of harmonic impedance depend on both network configurations and loads' configurations; • The distribution load owner will be responsible for changes of load configuration that affects harmonic voltage at PCC.	Regular meetings and load surveys are recommended to share network development scenarios that can affect harmonic performance at PCCs.

8.3 Optimised Harmonic Allocations for Large Network Scenarios

A large transmission system may have up to a few thousand network scenarios that can present practical challenges for harmonic allocation. Network impedances, which have direct impacts on *Influence Coefficients*, can vary significantly from one scenario to another as previously discussed. The question is which scenario should be chosen for harmonic allocation?

Without any structured guidelines/methodology to select the most suitable network scenario for different loads, allocation of harmonics can be very difficult in practice, even with the most advanced computer programming capability. Up until now, there is no methodology available in the literature that address this issue. Most utilities currently resource to their local knowledge, experience and intuitive thinking to select only a small number of network scenarios, or in most cases one typical network scenario, to carry out harmonic allocations. Practices can vary widely from one utility to another. However, so far none can address this issue effectively because ultimately only one scenario must be selected from a few thousand. In this section, existing industry practice is described for comparison purpose and a new optimisation method is proposed to not only select the best fit profile to suit a wide range of harmonic sources but also to optimise their maximum allocations for that harmonic source.

8.3.1 A Typical Existing Industry Practice

Transmission utilities currently use various approaches to select a network scenario to allocate harmonics to loads. One typical approach that is used by a number of transmission utilities in Australia is described here for reference and comparison purposes.

The responsible planning engineer selects a network scenario, which he/she considers as most likely to occur in the existing network. However, it is purely based on his/her own experience and knowledge of their systems at that particular time. The inclusion or exclusion of harmonic injection from existing loads totally depends on the utility engineer's discrete decision. It can be very subjective and inconsistent across different utilities as some existing sources may be included while others may be left out, depending on the experience and knowledge of the engineer who conducts the study. Once a network scenario is chosen, harmonic allocation is carried out according to the IEC report [10]. As discussed in previous chapters, the existing IEC allocation method would often result in under-allocations and sometimes over-allocation. Nevertheless, once the allocation is completed, the new load is represented as a harmonic current source to inject harmonics in a large number of network scenarios, typically from a few hundred to a few thousand depending on the size of the network. In this process, a large number of network scenarios are often reduced using the polygon impedance method described below to limit the number of network case studies. Busbar voltages are assessed for pre-connection compliance against planning levels. Any excessive voltages will require the allocations to be reevaluated and readjusted accordingly.

This method heavily depends on individual engineers who carry out harmonic allocation. Only one typical network scenario was chosen based on a highly subjective manner, out of a few thousand cases, for harmonic allocation. As discussed in Chapter 4, the transmission network impedances can vary significantly from one scenario to another. Therefore this approach will highly likely miss out on important network scenarios that may have material impacts on harmonic allocations and potential adverse effects on harmonic voltage performance. In addition, it does not maximise/optimise harmonic allocation based on network absorption capability. The chance to pick the best network scenario for harmonic allocations that best suit different load characteristics is only 0.033%, i.e. 1/3000, for a network with 3000 scenarios. A new method is required to select the best fit network scenario and optimise harmonic allocation to suit specific requirements of different harmonic sources.

Utilities and consulting engineers have often used the polygon impedance diagram, as shown in Figure 8.2 below, as a method to reduce a large number of network scenarios. The shape of the polygon is manually drawn by the engineer who carries out the analysis. There is no consistent rule as to how the polygon should be drawn/defined. The main purpose of the polygon is to form an envelope that covers all network scenarios within its boundary. Therefore, impedances along the boundary of the polygon would represent scenarios that are worse than those inside its boundary. Both the polygon and the number of points chosen to represent impedances inside its boundary totally depend on the experience of the engineer who carries out the analysis. There are no defined rules as to how many points should be chosen to represent the polygon, therefore its application can be inconsistent and highly subjective. An example below is used to demonstrate how a very large number of network scenarios can be reduced using this method. Unfortunately, this method cannot be used with the new allocation method, derived in Chapter 5, and the existing IEC allocation method as discussed below.

Example 1: A transmission system has 500 buses, 3000 network scenarios. Harmonic allocation is required for a load connected to a busbar. The frequency of interest is up to the 25^{th} harmonic.

For each element, e.g. $Z_{11}(h)$, of the 500 × 500 network impedance matrix, plot its impedances in the R/X plane at each harmonic frequency in the range of interest, as shown in Figure 8.2. The number of data points shown in this figure is from the case study network in Chapter 4. It only shows 22 values, representing 22 network scenarios, of the 5^{th} harmonic impedance at bus 1 ($Z_{11}(h=5)$) in the R/X plane. These points are then enclosed by an envelope, approximated by 8 data points in this case. The responsible engineer may choose a different number of data points, i.e. not necessarily has to be 8 points, to form the envelope. Alternatively, the number of data points on the border of the envelope may also be increased slightly, e.g. to 16 points to increase granularities. In this case, 22 data points now are represented by 8 data points envelope. Similarly, for 3000 network scenarios, 3000 data points can also be represented by a very small number of data points. Instead of having 3000 data points for each element of the 500 x 500 impedance matrix, there will only be 8 or 16 data points for each element. It is equivalent to the 99.7% and 99.4% reduction of the number of data points (network scenarios) for 8 and 16 points envelop respectively.

As far as harmonic frequency scanning study is concerned, the polygon impedance methodology can be used to reduce any large number of network scenarios down to a small number of cases. It is currently used by practitioners in the industry to reduce a large number of network scenarios required for checking pre-connection harmonic voltage compliance after harmonic allocations are completed. It is also a useful method to help to evaluate harmonic filter design once allocated currents are known. However, it cannot be applied to the new, and the existing IEC, harmonic allocation methods. The main reason for this incompatibility is because *Influence Coefficients* must be calculated based on impedances of each individual network scenarios. However, harmonic impedances obtained from the polygon, i.e. the reduced network scenarios (envelopes) can be from different scenarios because the shapes of the polygon are manually drawn up for every impedance at different harmonics, without any rules, as long as it provides an envelope around the impedance points on R/X plane. For example: the shape of the polygon impedance of $Z_{11}(h)$ would be completely different to the shape of the polygon of Z_{21}(h) and they can represent two completely different network scenarios. Therefore, they cannot be used together to calculate *Influence Coefficients* of any network scenario, hence harmonic global contributions cannot be determined. Ultimately, an *Influence Coefficient* cannot be calculated using $Z_{ii}(h)$ from one network scenario and $Z_{ij}(h)$ from another network scenario as it would have no practical meaning.

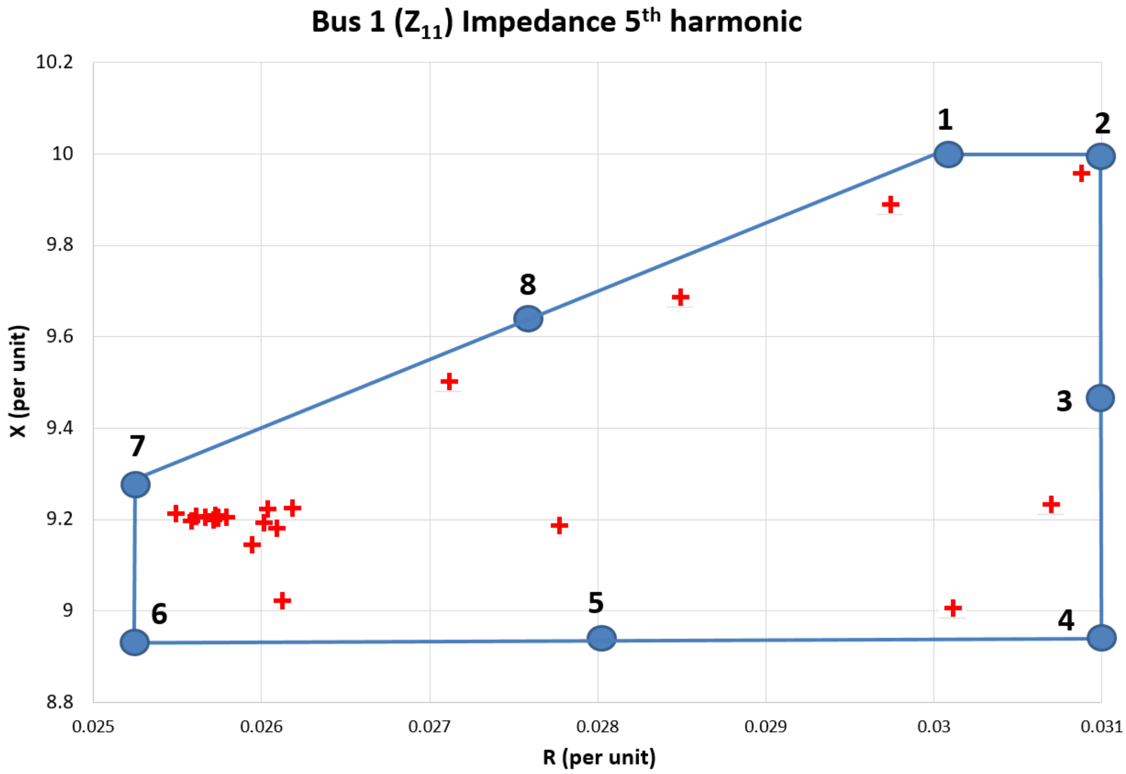


Figure 8.2 – Power system network impedance represented as a polygon in the R/X plane

8.3.2 Proposed Optimised Harmonic Allocations for Large Network Scenarios

As discussed in Chapter 6, the calculation of harmonic impedances is only applicable to the new allocation method and the IEC method. All other methods do not require harmonic impedances. This chapter proposes a new methodology to optimise harmonic allocations to best suit a wide range of harmonic sources. This methodology sets up criteria required to best fit harmonic profiles and utilises computer programs to carry out repetitive calculations and perform optimisation algorithm to select the final allocation to suit individual loads. The following steps are proposed:

(i) Step 1 (Optional): Exclude all network scenarios that have a very low probability, e.g. less than 5%, of occurring and with low impacts, i.e. would occur for too brief a time to have a significant impact. This elimination process heavily depends on the experience and knowledge of the engineer who carries out the task. It should only be done by experienced planning engineers, carefully, to avoid any potential issues. On the other hand, if a scenario is considered as rare to occur, but it may give a very high emission value when it occurs, should not be excluded. This step is optional as it only helps to remove a small number of network scenarios from the optimisation program. This step can be omitted as the computer programs can perform extra work to avoid mistakes due to a lack of knowledge and experience.

(ii) Step 2: Calculate harmonic impedance and *Influence Coefficient* matrices for each harmonic.

(iii) Step 3: For each network scenario, calculate the global harmonic contribution (G_{hm}) for each harmonic order as per equations (8.4) and (8,5), repeated from (5.8) and (5.9) respectively, satisfying *500 conditions* of *500 bus system*

Global contribution at Bus 1:

Condition 1:

$$G_{B1}(h) \leq \sqrt[\alpha]{\frac{S_{tS1}}{K_{1-1}^{\alpha}(h)\times(S_{tS1}-S_{1S})+K_{2-1}^{\alpha}(h)\times(S_{tS2}-S_{2S})+..+K_{n-1}^{\alpha}(h)\times(S_{tSn}-S_{nS})}} \times L_{HV-EHV}(h) \qquad (8.4)$$

Condition 2:

$$G_{B1}(h) \leq \sqrt[\alpha]{\frac{S_{tS1}}{K_{1-2}^{\alpha}(h)\times(S_{tS1}-S_{1S})+K_{2-2}^{\alpha}(h)\times(S_{tS2}-S_{2S})+..+K_{n-2}^{\alpha}(h)\times(S_{tSn}-S_{nS})}} \times L_{HV-EHV}(h) \qquad (8.5)$$

…..

Condition *n*:

(iv) Step 4: For each harmonic, select the lowest value of global harmonic contribution (*Ghm*) for the PCC, e.g. $G_{B1}(h)$ for bus 1.

(v) Step 5: Carry out harmonic allocation for loads at the PCC of interest-based on the chosen (*Ghm*) above and according to (5.13), repeated below as (8.6).

$$E_{U\,i}(h) = \sqrt[\alpha]{\left(G_m^{\alpha}(h) - \sum_j^n E_{Existing\_Loads\_j@m}^{\alpha}(h)\right)\left(\frac{S_i}{S_{tSm}-\sum_j^n S_{Existing\_Loads\_j@m}}\right)} \qquad (8.6)$$

(vi) Step 6: Repeat harmonic allocations from step 2 to 5 for all, e.g. 3000, scenarios.

At this point, presumably, there will be 3000 different sets of allocations, derived from 3000 network scenarios, for each harmonic level. Harmonic profiles of 3000 allocations can be very different from one case to another, therefore, optimisation criteria must be used to select only one allocation out of 3000 cases. It is proposed that harmonic profiles and the maximum Root Mean Square (RMS) of normalised allocation factors (F_{Max}), which will be further explained in step 7 below, be used as selection criteria for the optimisation algorithm.

(vii) Step 7: Optimise harmonic allocation from a large number of network scenarios. Two independent selection criteria are proposed below to suit a wide range of harmonic sources. One criterion is based on harmonic profiles to suit different sources, another gives a good indication of how close the allocation is to its respective planning level, e.g. based on the ratios between voltage allocations and planning levels. The allocation optimisation algorithm includes a three-step process, as described in Step 7A, 7B and 7C, which are explained below:

<u>Step 7A</u> – Optimisation based on Harmonic Profile: The aim is to find a harmonic profile that best matches the profile of the harmonic source of interest. For example, an SVC would require higher allocation at 5th, 7th and 11th harmonics, while a high switching frequency power electronic converter source would require more allocation at higher harmonic orders. The optimisation algorithm will select one allocation set, out of 3000 network scenarios, which have maximum 5th, 7th and 11th harmonic allocations, or highest allocation at high frequencies.

<u>Step 7B</u> – Optimization based on ratios between voltage allocations and respective planning levels. It aims to achieve maximum combined ratios across all harmonics, which is defined in this thesis as the *Maximum Root Mean Square (RMS) Normalised Allocation Factor* (F_{Max}) as per equation (8.7) and (8.8) below.

$$F_{RMS-NA}\,(a) = \sqrt{\sum_{h=2}^{n}\left(\frac{E_{Uhi}}{L_{HV-EHV}(h)}\right)^2} \tag{8.7}$$

$$F_{Max} = Max[F_{RMS-NA}(a)] \tag{8.8}$$

E_{Uhi}: Allocated harmonic voltage for the load (*i*) at harmonic order (*h*);
h: Harmonic order;
$L_{HV\text{-}EHV}(h)$: Planning level at harmonic order (*h*);
$F_{RMS\text{-}NA}(a)$: *Root Mean Square Normalised Allocation Factor* of network a scenario (*a*), i.e. the sum of the square of allocation divided by respective planning levels;
a: Network scenario 1, 2, …, p;
F_{Max}: Maximum value of $F_{RMS\text{-}NA}(a)$ from all network scenarios.

F_{Max} is essentially the measure, which amplified by the RMS function of sum square of as per (8.7), of how allocations are close to respective planning levels.

Depending on the anticipated characteristics of harmonic sources, criteria in steps 7A and 7B can be used separately or combined to deliver the best fit allocation. The recommendation for optimising harmonic allocation to different harmonic sources is summarised in Table 8.2 below.

<u>Step 7C</u> – Choosing the Optimal Network Scenario: It was recognised that depending on the number of network scenarios involved and load requirements as discussed in steps 7A and 7B, there may be no single network scenario that can meet all requirements, but several network scenarios. An additional tolerance factor is required to further optimise a network scenario that can meet all requirements set out in steps 7A and 7B. For example, it may not be possible to find one network scenario that can have a maximum 5th,7th and 11th harmonic profile. However, it may be possible to find a network scenario that has a maximum 5th harmonic profile, and an acceptable tolerance, ($Q_F(\%)$) - e.g. within 5%, applied to the 7th and 11th harmonic profiles. In this thesis, Q_F is defined as the *Tolerance Factor* that can be applied to individual selection criteria in steps 7A and 7B above. Q_F is the *maximum tolerance* that can be accepted, for one or more selection criteria, to yield an optimal network scenario that satisfies all requirements with acceptable tolerances.

Table 8.2 – Recommended Optimisation Options for Different Harmonic Sources

Plants/Loads' Type	Anticipated Characteristics of Harmonic Sources	Recommended Allocation	Recommended Optimisation Options
Plants: SVC, STATCOM, Solar, Wind, Battery Storage, HVDC and Thyristor Control, mining loads, Industrial loads, e.g. metallurgical refineries.	• Mostly current source • Very high certainty of harmonic profiles.	Current (E_{Ihi})	Optimization based on Harmonic Profile.
Loads: Distribution loads at the bulk supply point	• Very low certainty of harmonic profiles	Voltage (E_{Uhi})	Optimization based on the Maximum Root Mean Square (RMS) Normalised Allocation Factor (F_{Max})

The seven (7) step process to optimise harmonic allocation for loads in transmission systems described above is summarised in the flow chart in Figure 8.3 below.

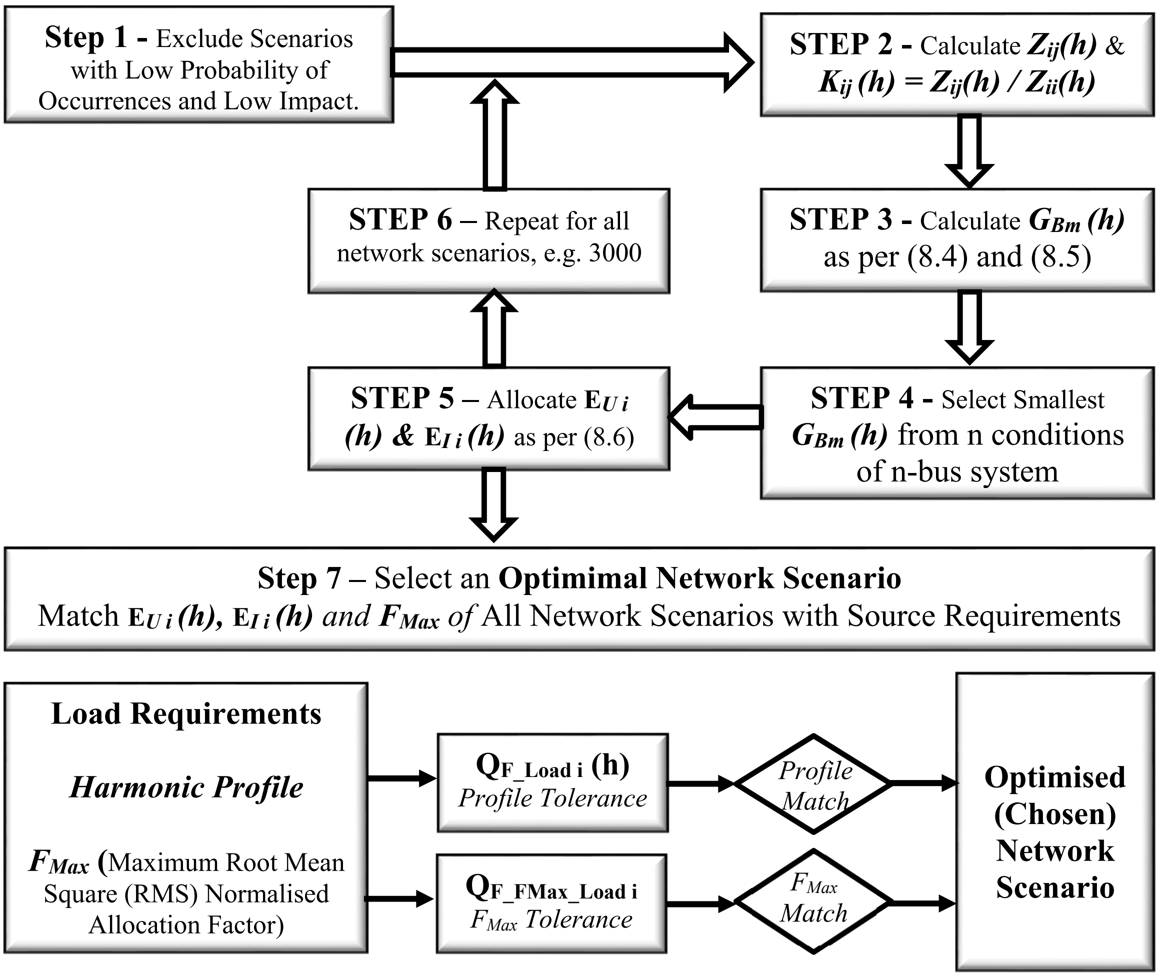


Figure 8.3 – Proposed Optimised Network Scenarios for Loads in Transmission Systems Flow Chart

$Q_{F\_Load\ i}$ *(h)*: is the maximum harmonic profile tolerance, expressed in percentage, of E_{U_i} *(h)* or E_{I_i} *(h)* with respect to their maximum values, e.g. The maximum voltage allocation of 5th harmonic E_{U_i} (5th) is chosen from 3000 network scenarios. For example $Q_{F\_Load\ 11}(5^{th})$ = 5% means that any scenario that has 5th harmonic voltage allocation (E_{U_i} *(5th)*), for Load 11, is greater or equal to 95% (i.e. 100% – 5%) of the maximum 5th harmonic voltage allocation (chosen from 3000 cases) will be included in the optimisation.

$Q_{F\_FMAx\_Load\ i}$: is the tolerance, expressed in percentage, of F_{Max} with respect to the maximum F_{Max} value. Similarly, the maximum value of F_{Max} is chosen from 3000 network scenarios. For example, $Q_{F\_FMax\ Load\ 11}$ = 5% means that any scenario that has F_{Max}, for Load 11, is greater or equal to 95% of the maximum F_{Max} will be included in the optimisation.

Depending on load requirements, either or both $Q_{F\_Load\ i}$ *(h)* and $Q_{F\_FMAx\_Load\ i}$ (in percentage) can be adjusted until only one scenario can satisfy all requirements. The optimisation process can be easily implemented using computer programming, e.g. MATLAB or Visual Basic for Application (VBA).

Practical application of the proposed optimised allocation method for loads in transmission systems is demonstrated in section 8.3.3 below using the case study network in Figure 3.1, in Chapter 3, which has 22 network scenarios. In this thesis, the harmonic allocation for 22 network scenarios was performed using the MATLAB program. The optimisation of network scenarios is implemented using VBA codes in excel.

8.3.3 Practical Application of Proposed Optimised Harmonic Allocation Method

A case study was conducted to optimise network scenarios that best suit harmonic allocations to Load 11 (244.73 MVA) and Load 12 (151 MVA) connected to Bus 1, as per Figure 3.1, in Chapter 3. In this case study, the new harmonic allocation method derived in Chapter 5 was applied to 22 network scenarios, which were described in Table 4.2, in Chapter 4. The main purpose of this case study is to demonstrate the practical application of the optimised harmonic allocation method, as described in section 8.3.2 above. The aim is to choose an optimal network scenario that best suit the profiles of Load 11 and Load 12 and to achieve maximum allocations relative to planning levels across the harmonic spectrum of interests.

The allocation and optimisation processes are carried out following the Flow Chart in Figure 8.3 above. The network optimisation process, steps 7A, 7B and 7C, are performed using VBA codes in excel. The following cases were considered for Load 11 and Load 12 requirements:

i. **Case A**: Load 11 requires higher allocations for 5th, 7th and 11th harmonics;
ii. **Case B**: Load 11 requires higher allocations for 21st, 23rd and 25th harmonics;
iii. **Case C**: Load 12 requires higher allocations for 5th, 7th and 11th harmonics;
iv. **Case D**: Load 12 requires higher allocations for 21st, 23rd and 25th harmonics;

v. **Case E & F**: Load 11 requires higher allocations for 5^{th}, 7^{th} and 11^{th} harmonics combined with Load 12 requires high allocations for 21^{st}, 23^{rd} and 25^{th} harmonics. Both cases E and F have the same load requirements, but two options for network scenarios are possible depending on the optimisation of *Profile Tolerances* (Q_{F_11} , Q_{F_12}) and *Maximum RMS Normalised Allocation Tolerances* ($Q_{F\_FMax\_11}$ *and* $Q_{F\_FMax\_12}$);

vi. **Case G & H**: Load 12 requires higher allocations for 5^{th}, 7^{th} and 11^{th} harmonics combined with Load 11 requires high allocations for 21^{st}, 23^{rd} and 25^{th} harmonics. Both cases G and H have the same load requirements, but two options for network scenarios are possible depending on the optimisation of *Profile Tolerances (Q_{F_11} , Q_{F_12})* and *Maximum RMS Normalised Allocation Tolerances* ($Q_{F\_FMax\_11}$ *and* $Q_{F\_FMax\_12}$).

Harmonic allocation results for each case, from A to H, are recorded in Table G.1 to Table G.8 respectively in Appendix G. An optimised network scenario was selected for each case, which is summarised in Table 8.3 below, based on harmonic profiles and maximum *RMS Normalised Allocation Factor* to suit load requirements. For example: In case A, Load 11 requires maximum 5^{th}, 7^{th} and 11^{th} harmonic profile as well as maximum *RMS Normalised Allocation Factor* (F_{Max}), harmonic allocations from network scenario 3 would be best for Load 11. However, if Load 11 requires a maximum of 21^{st}, 23^{rd} and 25^{th} harmonics then scenario 20 would be most suitable.

Harmonic Profile Tolerances (Q_{F_11}, Q_{F_12}) and Maximum RMS *Normalised Allocation Factor* ($Q_{F\_FMax\_11}$ and $Q_{F\_FMax\_12}$) play a critical role in the optimisation process as they can be adjusted for individual harmonics to find the best suit network scenario. *Harmonic Profile Tolerances* (Q_{F_11} , Q_{F_12}) can be varied independently for each harmonic to achieve different harmonic profiles for loads as shown in Table G.1 – G.8 in the Appendix section.

A comparison between the proposed optimised network scenario method and the current industry practice is summarised in Table 8.4 below. Assuming that the responsible planning engineer chose network scenario 13 to carry out harmonic allocation as per the existing industry practice. The optimised network scenarios, e.g. Scenario 3 or 20, as shown in Table 8.4 would result in the best suit allocations that satisfy Load 11 and Load 12 requirements. In this case, the industry practice would result in under allocation and cannot satisfy load requirements. Significant harmonic allocations can be achieved for load 11, e.g. 98.9% improvement on 7^{th} and 56.7% on 23^{rd} harmonics, while negligible reductions on the 11^{th} and 21^{st} harmonics were observed. Conversely, if the industry practice is used in conjunction with the existing IEC allocation method, it can result in over allocations that further complicates the allocation process unnecessarily.

Table 8.3 – Summary of Optimised Network Scenario Based on Load's Harmonic Profile and Maximum RMS Allocation Factors

Case ID	**E_{U_5} (%)**	**E_{U_7} (%)**	**E_{U_11} (%)**	**Profile 5^{th} 7^{th} 11^{th}**	**F_{Max}**	**E_{U_21} (%)**	**E_{U_23} (%)**	**E_{U_25} (%)**	**Profile 21^{st} 23^{rd} 25^{th}**	**F_{Max}**	**Optimal Network Scenario**
Planning Level (%)	2.000	2.000	1.500			0.200	0.890	0.820			
	Load 11 requires 5^{th}, 7^{th} and 11^{th} Profile					Load 11 requires 21^{st}, 23^{rd} and 25^{th} Profile					
A	1.419	1.419	0.396	Load 11	2.093						3
B						0.132	0.663	0.642	Load 11	2.862	20
	Load 11 requires 5^{th}, 7^{th} and 11^{th} Profile					Load 12 requires 21^{st}, 23^{rd} and 25^{th} Profile					
C	1.005	1.005	0.311	Load 12	2.191						3
D						0.104	0.521	0.504	Load 12	2.161	20
	Load 11 requires 5^{th}, 7^{th} and 11^{th} Profile AND Load 12 requires 21^{st}, 23^{rd} and 25^{th} Profile										
E (Opt 1)	1.419	0.994	0.399	Load 11	2.862	0.104	0.521	0.504	Load 12	2.161	20
F (Opt 2)	1.419	1.419	0.396	Load 11	2.903	0.124	0.357	0.504	Load 12	2.191	3
	Load 12 requires 5^{th}, 7^{th} and 11^{th} Profile AND Load 11 requires 21^{st}, 23^{rd} and 25^{th} Profile										
G (Opt 1)	1.005	1.005	0.311	Load 12	2.191	0.157	0.454	0.642	Load 11	2.903	3
H (Opt 2)	1.005	1.004	0.308	Load 12	2.224	0.139	0.509	0.642	Load 11	2.959	19

Table 8.4 – Comparison between Optimised Network Scenarios Versus Existing Industry Practice

Network Scenario	5th (%)	7th (%)	11th (%)	THD 5 7 11 (%)	F_{Max} 5 7 11	Network Scenario	21st (%)	23rd (%)	25th (%)	THD 21 23 25 (%)	F_{Max} 21 23 25
Load 11											
3 Optimised	1.419	1.419	0.396	2.045	1.038	20 Optimised	0.132	0.663	0.642	0.932	1.266
13 Existing Industry Practice	1.209	0.713	0.397	1.459	0.750	13 Existing Industry Practice	0.134	0.423	0.642	0.780	1.134
Variance (%)	17.4	98.9	-0.20	40.2	**38.3**	Variance (%)	-1.3	56.7	0.0	19.5	**11.7**
Load 12											
3 Optimised	1.005	1.005	0.311	1.455	0.740	20 Optimised	0.104	0.521	0.504	0.732	0.995
13 Existing Industry Practice	0.856	0.505	0.312	1.042	0.539	13 Existing Industry Practice	0.105	0.332	0.504	0.613	0.891
Variance (%)	17.4	98.9	-0.3	39.6	**37.4**	Variance (%)	-1.0	56.8	0.0	19.5	**11.8**

8.4 Proposed Harmonic Planning for Renewable Zones

Chapter 7 highlighted the important role of harmonic impedance attenuation and network absorption capability in harmonic allocation. As more renewable generation sources penetrate the system, harmonics increase more rapidly while network absorption remains the same, or could even be reduced when existing synchronous machines are retired. The worst scenario would be due to increases in renewable harmonics as well as premature retirement of synchronous rotating machines at the same time. As the penetration of renewable generation increases, the transmission network will ultimately reach its maximum absorption capability at some points in time, assuming that impedance attenuation effects from loads remain the same. The case study in Chapter 7 simulated that before the connection of three new renewable generators, the remaining spare supply capacity was only 10% of the total supply capacity at all busbars, which is equivalent to the remaining 10% of network absorption capability. As discussed in Section 7.2, if this margin is reduced down to, say 2.5%, before the installation of renewable generators then each of three renewable generators can only receive 2.5%, i.e. total of 7.5% of the remaining absorption capability. What will happen after this point - does it mean that no more renewable generators can be connected to the transmission network? This would be considered a compromised position for all network participants and should be avoided. Therefore, a proactive planning approach is required to prevent the network from getting to this point.

The 2020 Integrated System Plan (ISP) published by AEMO for the Australian Electricity Market [65] recently published a transition plan to achieve a higher renewable target. This pathway includes a target of a 200% increase of DER and over 50% of VRE (Variable Renewable Energy – Wind and Solar), coupled with a steep reduction of synchronous rotating machines, e.g. retirement of 63% coal fire synchronous machines by 2040. It means that significant harmonic absorption capability, which supports existing future harmonic sources, will be removed from the network. This is coupled with a very large increase of harmonic sources from power electronic converters being integrated into the system at the same time. This is a realistic plan that AEMO has published to provide guidance and certainty for market participants and network owners to plan. According to the ISP, it is inevitable that additional network absorption capability will be required to accommodate a large increase of harmonic sources, from power electronic equipment and renewable generators, penetrating the power system.

In July 2020, local state governments in Australia, e.g. Queensland Government have also introduced incentives for renewable investors and directly invest in the development of renewable zones within the Queensland network. Generally, there are two scenarios of large renewable generators connect to transmission system: (i) individual generators connect to various buses in the system; and (ii) a group of renewable generators connect to a designated "Renewable Zone" – a high concentration of renewable generation in an electrical network area. Harmonic issues exist in both cases, however, the latter, i.e. Renewable Zone, is more onerous than the former as a high concentration of harmonic sources in a network area, especially when the remaining absorption capability impedance attenuation effects are low. The following stages are proposed for harmonic planning and management of a network with high renewable generation and very low harmonic absorption capability:

(i) Stage 1: Introduce forward harmonic planning and incorporate the process as part of the future network development of the Strategic Asset Management Plan (SAMP), which supports AEMO ISP 2020 and the implementation of Renewable Zones as mentioned above.

(ii) Stage 2: Introduce power quality as an ancillary service, among existing voltage and frequency control ancillary services, in the National Electricity Rules that will allow TSOs, DSOs and network participants to buy and sell Power Quality Ancillary Services (PQAS). Under such arrangement, network utilities (TSOs and DSOs) have the suitable infrastructure to manage and host, e.g. buy and sell, PQAS on behalf of all network participants. Therefore, trading of PQAS is best to be conducted through TSOs to optimise the use of network infrastructure and reduce the service cost of PQAS.

(iii) Stage 3: Recommend AEMO and AER to update existing guidelines to include the optimised harmonic allocation methodology proposed in section 8.3, including the flow chart in Figure 8.3

for transmission systems. This method provides the flexibility to manage the sharing of network supply capacity, i.e. including network absorption and attenuation, among busbars as well as a process to find an optimised network scenario that best suits specific requirements of different harmonic sources.

(iv) Stage 4: Recommend TSOs to consider principles of sharing of harmonic absorption available in their network to facilitate and support the trading of PQAS among network participants. For example, a synchronous generator may not be required to generate active power due to demands are met by solar and wind plants. These synchronous machines should be able to participate in PQAS (and Voltage Control Ancillary Services – VCAS) to help to stabilise the system and absorbing harmonics. The PQAS would provide more financial incentives to help to retain/extend synchronous generators in the network longer. Practical applications of the PQAS through the TSOs network can be demonstrated below:

a. TSOs may purchase additional network absorption capability from other network participants, e.g. synchronous machine owners or new synchronous condensers, and sell PQAS to renewable generators.

b. TSOs may seek agreement with AEMO, AER and other network participants to fund a dedicated PQAS project, e.g. install several synchronous condensers or carry out network augmentation, to create a pool of network absorption capability and allocate relevant portions to network participants. The cost of a dedicated PQAS project can be shared across multiple renewable generators via the Connection and Access Agreements (C&AAs).

(v) Stage 5: Recommend TSOs to initiate the PQAS prospectus to invite relevant network service providers and network participants connected to their network, including renewable generators to participate in the scheme. Trading of PQAS can be executed through the existing C&AAs process, which is a well-established process and does not require additional administration service cost, to minimise the overall cost of the PQAS scheme.

8.5 Summary

A strategic harmonic management planning framework has been proposed in detail, including relevant principles, allocation procedures and planning examples. This framework has drawn on results and analysis from previous Chapters 2 – 4. It integrated harmonic management solutions recommended in Chapters 5 and 6 and harmonise them with practical improvements recommended in Chapter 7. Both current and voltage allocation have been recommended to suit different type of loads/harmonic sources. A new methodology was proposed to optimise harmonic allocations, from a large number of network scenarios to best suit a wide range of harmonic sources. Methodical planning procedures and workflow, from the connection enquiry stage through to the Connection and Access Agreement (C&AA), have been being proposed in detail and take into account network scenarios affecting harmonic allocation and pre-connection compliance assessment.

It was recognised that harmonic allocation to loads in transmission systems, in practice, can be a very exhaustive task and time-consuming process due to the number of network scenarios involved. This chapter has recommended a practical approach to perform optimisation on harmonic allocations to suit a wide range of harmonic sources using automatic software scripts. The optimisation of harmonic allocations was based on two independent criteria – THD_V and best-fit harmonic profiles, and optimisation factors to suit different harmonic sources. Finally, detailed harmonic planning for renewable zones in transmission system was also recommended to provide additional considerations for harmonic management of a network with high renewable penetration. The Power Quality Ancillary Services (QPAS) for renewable zones was proposed to solve network harmonic constraints under circumstances that conventional technical solutions cannot provide adequate solutions. These scenarios may occur sooner than previously anticipated, especially when high penetration of renewable generators is coupled with early retirements of synchronous generators.

9 Conclusions and Future Work

9.1 Conclusions

This thesis has derived a new harmonic allocation strategy, which includes a new allocation method built on the IEC principles and addresses some of the shortcomings of the IEC approach. This strategy is suitable for allocating emissions to a wide range of harmonic sources, including non-linear energy consumption loads at bulk supply points, large industrial loads as well as renewable generators, in transmission systems. The new harmonic allocation strategy:

(i) is an effective harmonic planning tool that allows planners to regulate network absorption capability of the transmission network, with the focus on maximising harmonic global contributions at PCCs;

(ii) sets up a harmonic management framework, including detailed workflow and boundary of responsibilities, to support the practical application of the new harmonic allocation method;

(iii) that optimizes harmonic allocations for any transmission networks, with a large number of network scenarios, based on the combined criteria of Total Harmonic Distortion Voltage (THDV) and harmonic profiles; and

(iv) is a proposal implement harmonic planning for Renewable Zones and to introduce a new Power Quality Ancillary Service (PQAS), which are similar to the existing Frequency Control Ancillary Services (FCAS) and Voltage Control Ancillary Services (VCAS), to underpin AEMO 2020 Integrated System Planning (ISP) roadmap published in August 2020.

Key information relevant to this thesis has been critically analysed in the literature review section. It was identified that, unlike distribution systems, harmonic studies for transmission systems require a more detailed and sophisticated modelling approach to cater for the extent of sensitivities in regards to harmonic impedances. The identified CIGRE guideline for modelling would be recommended as a minimum requirement for such studies, ensuring important issues such as resonances, which occur more often in transmission systems, are accommodated. It was also identified that while short circuit power associated with inductive elements, e.g. synchronous machines, provide a good indication for harmonic absorption capability at PCCs, it does not necessarily apply for short circuit power associated with meshed transmission lines (i.e. further into the network) due to increased chances of resonances across the harmonic frequency spectrum.

Allocation methods within existing harmonic standards can be categorized in two approaches: (i) simple approaches, e.g. IEEE 519, AS 2279.2, and ESAA (One-Third Planning) method, which do not depend on network impedances (and network scenarios), and rely on short circuit power at PCCs; and, (ii) more sophisticated approaches, e.g. IEC, that heavily rely on network impedances which are directly influenced by network scenarios. Their practical application depends on the complexity level of different network, e.g. the IEEE 519 and IEC methods are better suited to distribution and transmission network allocations respectively. Overall, all existing harmonic allocation methodologies to date have deficiencies that limit the effectiveness of their practical application to loads in transmission systems.

A realistic case study transmission network was developed to sufficiently represent the complexities of a typical transmission system. Specifically, a network very similar to an area of a transmission system in Australia was chosen. The IEC allocation method was practically applied to allocate harmonics to loads of the case study network. Through the allocation process, a number of deficiencies associated with the existing IEC methodology were demonstrated. These are listed below:

(i) The methodology likely results in either under allocation or over-allocation, but by design the former occur much more often than the latter, due to inaccurate prediction of future loads;

(ii) The method for sharing planning levels between HV-EHV busbars does not allow the network absorption capability to be utilised effectively;

(iii) The method to assess *total future load* (S_t) versus the *total supply capacity* at bus *m* (S_{tSm} – new terminology proposed in this thesis) at each PCC is ambiguous due to no clear distinction between the *total loads* and *total supply capacity* at PCCs;

(iv) The method for allocating individual limits to loads does not explicitly take into account pre-existing harmonic sources, which cause background harmonics, hence the harmonic voltage at PCCs can exceed planning levels unknowingly.

A subsequent detailed case study was conducted to identify how challenges, such as large network scenarios and complex impedances, which are considered unique to transmission systems, can significantly affect harmonic allocations. Network scenarios have direct impacts on harmonic impedances, *influence coefficients, global contribution* and the eventual harmonic allocation. The biggest issue for harmonic allocations in transmission system is the significant changes of harmonic impedances, from one network scenarios to another. Based on a simplified 7-bus 132kV case study network, changes of harmonic allocation under different network scenarios can be from 24% to 97% of voltage emission allocation for some harmonic frequencies.

A new harmonic allocation methodology was developed to overcome deficiencies associated with the existing IEC approach. The new method maximises harmonic allocation to loads through effective utilisation of network absorption capabilities, while ensuring that planning levels will not be exceeded. It includes the following features: (i) clarification of key differences between total loads versus total supply at busbars and the methodology to assess these quantities at PCCs; (ii) spare harmonic absorption capability, which can be represented by the supply capacity, can be shared among busbars to increase *global harmonic contribution* at PCCs; (iii) existing harmonic sources, which take up their full allocations and inject harmonics at PCCs, are included in the allocation process to account for background harmonics contribution from existing sources; and (iv) spare network absorption capability can be regulated, through the reserved spare capacity, to suit different PCCs or network areas.

The practical application of the new harmonic allocation was compared with other existing allocation methods and critically analysed. It indicated that the simple allocation methods, such as the AS 2297.2, IEEE 519 and the ESAA (One-Third Planning) method, would suit distribution systems better than transmission systems because they are simple and do not require complex network models and calculations for harmonic impedances as seen in transmission systems. In most cases, their application to transmission systems results in very high harmonic voltages at PCCs due to changes of impedances and background harmonics have not been properly accounted for. Conversely, the application of more sophisticated methodologies, e.g. the IEC approach and the new allocation method derived in Chapter 5 result in harmonic voltages that comply with planning levels. In particular, the new allocation method was recommended in Chapter 6 as it maximizes the utilization of network absorption capability to increase allocations to loads, while the IEC method mainly constrains allocations to not exceeding planning levels and yields much lower allocations (under-allocations). Depending on network scenarios, the new allocation method can increase harmonic allocations to loads from 2.75% to 114.67% at different harmonics.

The new harmonic allocation methodology was used to allocate harmonic emissions to renewable generators, namely large inverter installation associated with wind and solar farms. Renewable generators produce significant harmonics but offer a negligible contribution to the harmonic absorption capability of the network, thus, it is unfair if renewable generators are given the same allocations as non-linear loads, which contribute to harmonic power absorption and impedance attenuation. It was recommended that renewable generators be given a smaller share of network absorption capability compared to non-linear loads based on the same MVA size. The allocations can be divided equally among a number of renewable generators sharing the remaining capacity at PCCs.

The new allocation method provides an effective tool to regulate the sharing of network absorption capability among harmonic sources. This method allows network planners to regulate network absorption capability to suit different harmonic sources at PCCs in the network. A range of practical solutions has also been recommended, e.g. installing synchronous condensers or having renewable generators connected closer to load centres, to better manage network absorption capability and enhance the utilisation of harmonic absorption capabilities.

A strategic harmonic management planning framework has been proposed to support the practical application of the new harmonic allocation and improve harmonic planning management for transmission systems. A detailed harmonic allocation process and associated workflow, taking into account network scenarios affecting harmonic allocation and pre-connection compliance assessment, were proposed to provide a clear guideline for network planners. Allocation expressed as both current and voltage emissions have been recommended to suit different types of loads/harmonic sources. Furthermore, a new method was also proposed to optimise harmonic allocation, from a large number of network scenarios to best suit different harmonic profiles of different harmonic sources.

Power Quality Ancillary Service (PQAS) for renewable zones was proposed to solve network harmonic constraints under circumstances that technical solutions cannot provide adequate solutions. The main purpose of PQAS is to provide a sustainable economic solution to underpin a wide range of technical solutions that can be adapted to support network scenarios with higher penetration of harmonic sources that exceed the existing network absorption capability. 2020 Integrated System Plan (ISP) – a pathway to 2020, published in August 2020 by AEMO, provides clarity and certainty for further network augmentation that is necessary to support the ISP transition plan. PQAS is proposed as an initiative to support the ISP of AEMO concerning harmonic management required for transmission systems with high penetration of renewable generation sources.

9.2 Recommendations for Future Work

Harmonic allocation in transmission systems requires more detailed and sophisticated models. In particular accurate models of three-phase network elements and/or their single-phase equivalent are essential. Currently, the CIGRE guideline provides a reasonable approach using single-phase equivalent based harmonic modelling. However, it has been recognised that this modelling approach is still very much theoretical, which cannot accurately capture complex responses of network elements and harmonic producing plants in real operational networks. Further work is required to obtain field data and better match models to real network components. Validation of theoretical models against field measurements is very important for transmission networks with high penetration of power electronic converters, such as wind, solar, battery storage, STATCOMs, etc. Complex and dynamic interactions between proprietary control schemes and sensor systems, on the DC side of converters, and the AC system need to be measured across the network to support theoretical models.

Many power electronic-based harmonic sources, with sophisticated control schemes, inject harmonics at a high-frequency range, e.g. between 50th and 100th harmonic orders. Thus, existing modelling techniques need to be further advanced to include frequencies up to the 100th harmonics, such that their dynamic and complex interactions with the system are better understood and modelled accurately. With the availability of harmonic measurement systems, e.g. Power Quality meters, Phase Measurement Units (PMUs) and more advanced analytic software, it is proposed that harmonic measurements be conducted in both laboratory and field environment to provide the above-mentioned necessary calibrations to the network models.

Generally, many utilities are still very reactive in managing harmonics in their network. Measurements are only examined when there is a complaint from a customer or an incident in the network has occurred. There appear to be a lack of enforceable rules for proactive monitoring, auditing measurement systems and validating network models to achieve better harmonic management. More valuable information can be obtained if single-phase harmonic currents are monitored for all connections at relevant PCCs. In addition, both field and laboratory measurements are very essential for refining network component models as discussed above. Further studies should be conducted to improve harmonic models for transmission network elements, including interactions between passive (non-linear) loads and active (converter type) loads.

The application of existing summation law exponents in the IEC methodology suggests phase and time diversity increases with harmonic frequency. While it is appreciated that low order harmonics have a more significant impact on the heating of equipment, not all equipment connected to transmission networks produce these low order harmonics. In practice, power electronic converters often produce high order harmonics, e.g. above 50th order, and their phase and time diversities are not yet fully understood. Further studies, using more sophisticated network models and field measurements, should be conducted to examine the effectiveness of the existing summation law exponents, and adjust as necessary, to further improve harmonic management for modern power systems with high penetration of power electronic sources.

Statement of Original Contributions

The original contributions of this thesis include the following that will assist in the management of harmonics in transmission systems:

(i) A detailed case study was conducted to provide fundamental information on, and comprehensive knowledge of, key contributing factors associated with the complexity of transmission network impedances. Highly unpredictable series and parallel resonances often occur, due to long transmission lines and capacitors, across the harmonic spectrum and their dependency on network scenarios are major issues. The study points to the need for more detailed and sophisticated network models for transmission systems.

(ii) A new harmonic allocation method was recommended based on the IEC/TR 61000-3-6, Ed. 2:2008 methodology but include several amendments, to overcome deficiencies of this method. It aims to improve the useability and the effectiveness, which is interpreted in this thesis as the ability to maximise harmonic allocation to loads while ensuring emissions are compliant with planning levels, of the IEC methodology.

(iii) A detailed evaluation of the practical application of the existing harmonic allocation method and the new allocation method was conducted. The results suggested that the new harmonic allocation method derived in the thesis is the most suitable allocation method for loads in transmission systems.

(iv) A realistic transmission network of 10-buses was modelled, having high penetration levels of renewable generators, and used as a case study to comprehensively investigate the practicality and effectiveness of the new harmonic allocation method for renewable generators in the transmission system. The outcomes lead to a number of practical recommendations and improvement options for network owners, operators and regulators to consider for harmonic management in transmission systems with high penetration levels of renewable generation sources.

(v) This thesis proposes a strategic harmonic management workflow to support the practical application of the recommended harmonic management solutions stated above to transmission systems with complex impedance characteristics, a very large number of network scenarios and high penetration levels of renewable generation sources. This workflow, includes strategic network area planning, harmonic allocation process and recommended allocation quantities (i.e. voltage versus current) that best suit different types of loads.

(vi) The work completed covers a new harmonic allocation optimisation method to select one or more network configurations, from a very large number of network scenarios to best fit specific requirements of different types of harmonic sources. This method aims to overcome challenges associated with transmission systems with a large number of network scenarios.

(vii) The thesis proposes new harmonic planning practices to support the Renewable Zones initiatives in Australia. It recommends a number of forwarding planning stages for practical harmonic planning and management of a network with high renewable generation and reduced harmonic absorption capability.

Publications arising from work presented in this thesis

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Appendix A – References of Existing and Superseded Standards

A.1 IEC/TR 61000-3-6, Ed. 2.0 (2008)

Table A.1 – Indicative planning levels for harmonic voltages (in percent of the fundamental voltage) in MV, HV and EHV power systems.

Odd Harmonic Non-multiple of 3			Odd Harmonics Multiple of 3			Even Harmonics		
Harmonic Order (h)	Harmonic Voltage (%)		Harmonic Order (h)	Harmonic Voltage (%)		Harmonic Order (h)	Harmonic Voltage (%)	
	MV	HV-EHV		MV	HV-EHV		MV	HV-EHV
5	5	2	3	4	2	2	1.8	1.4
7	4	2	9	1.2	1	4	1	0.8
11	3	1.5	15	0.3	0.3	6	0.5	0.4
13	2.5	1.5	210	0.2	0.2	8	0.5	0.4
$17 \leq h \geq 49$	$1.9\frac{17}{h} - 0.2$	$1.2\frac{17}{h}$	$21 < h \geq 45$	0.2	0.2	$10 \leq h \geq 50$	$0.25\frac{10}{h} + 0.22$	$0.19\frac{10}{h} + 0.16$

Indicative planning levels for the total harmonic distortion are THD_{MV} = 6.5% and $THD_{HV\text{-}EHV}$ = 3%.

A.2 IEEE Std 519 (2004)

Table A.2 – IEEE Std 519-2014 Voltage Distortion Limits:

Bus Voltage V at PCC	Individual Harmonic (%)	Voltage Total Harmonic Distortion (%)
$V \leq 1.0$ kV	5	8.0
1.0 kV < V ≤ 69 kV	3	5.0
69kV < V ≤ 161 kV	1.5	2.5
161 kV < V	1.0	1.5[a]

[a] *High-voltage systems can have up to 2% THD where the cause is an HVDC terminal whose effects will have attenuated at points in the network where future users may be connected.*

Table A.3 – IEEE-519 – 2014 Current Distortion Limits for Systems Rated 120V through 69kV

Maximum Harmonic Current Distortion in Percent of I_L						
Individual Harmonic Order (Odd Harmonic) a,b						
I_{SC}/I_L	3≤ h <11	11≤ h <17	17≤ h <23	23≤ h <35	35≤ h ≤50	TDD
< 20c	4.0	2.0	1.5	0.6	0.3	5.0
20 < 50	7.0	3.5	2.5	1.0	0.5	8.0
50 < 100	10.0	4.5	4.0	1.5	0.7	12.0
100 < 1000	12.0	5.5	5.0	2.0	1.0	15.0
< 1000	15.0	7.0	6.0	2.5	1.4	20.0

Table A.4 – IEEE-519 – 2014 Current Distortion Limits for Systems Rated above 69kV through 161kV

Maximum Harmonic Current Distortion in Percent of I_L						
Individual Harmonic Order (Odd Harmonic)[a,b]						
I_{SC}/I_L	3≤ h <11	11≤ h <17	17≤ h <23	23≤ h <35	35≤ h ≤50	TDD
< 20[c]	2.0	1.0	0.75	0.3	0.15	2.5
20 < 50	3.5	1.75	1.25	0.5	0.25	4.0
50 < 100	5.0	2.25	2.0	0.75	0.35	6.0
100 < 1000	6.0	2.75	2.5	1.0	0.5	7.5
< 1000	7.5	3.5	3.0	1.25	0.7	10.0

Table A.5 – IEEE-519 – 2014 Current Distortion Limits for Systems Rated above 161kV

Maximum Harmonic Current Distortion in Percent of I_L						
Individual Harmonic Order (Odd Harmonic)[a,b]						
I_{SC}/I_L	3≤ h <11	11≤ h <17	17≤ h <23	23≤ h <35	35≤ h ≤50	TDD
< 25[c]	1.0	0.5	0.38	0.15	0.1	1.5
25 < 50	2.0	1.0	0.75	0.3	0.15	2.5
≤ 50	3.0	1.5	1.15	0.45	0.22	3.75

[a]*Even harmonics are limited to 25% of the odd harmonic limits above.*

[b]*Current distortions that result in a dc offset, e.g. half-ware converters, are not allowed.*

[c]*All power generation equipment is limited to these values of current distortion, regardless of actual I_{SC}/I_L.*

Table A.6 – IEEE-519 – 2014 Recommended Multipliers for Increases in Harmonic Current Limits

Harmonic Orders Limited to 25% of Values Given in Table 2.5, 2.6 and 2.7 above	Multiplier
5, 7	1.4
5, 7, 11, 13	1.7
5, 7, 11, 13, 17, 19	2.0
5, 7, 11, 13, 17, 19, 23, 25	2.2
↓	↓

A.3 AS 2279.2 (1991 - Superseded)

Table A.7 – AS 2279.2 – 1991 Recommended Multipliers for Increases in Harmonic Current Limits

Supply System	Voltage at Point of Common Coupling (PCC) (kV)	Total Harmonic Voltage Ratio (%)	Individual Harmonic Voltage Ratio (%)	
			Odd	Even
Primary and Secondary Distribution	≤ 33	5	4	2
Transmission and Sub-transmission	22, 33 and 66	3	2	1
	≥ 110	1.5	1	0.5

Table A.8 – AS 2279.2 – 1991 Diversity Factors Applicable to Multiple Equipment in an Installation

Category	Type and operating condition of a number of convertors	Diversity factor
1	Controlled or uncontrolled convertors when a single convertor provides 60% of more of the arithmetic total of the harmonic currents of all equipment in the installations	1.0
2	Uncontrolled convertors (therefore a high probability of phase coincidence at time of peak harmonic production)	0.9
3	Convertors with control of firing angle operating on coordinated duty cycles (therefore a fair probability of coincidence of peak harmonic production of a number of units)	0.75
4	Convertors with control of firing angle, operating independently, intermittently or with uncoordinated duty cycles (therefore a low probability of coincidence of peak harmonic production and then only for a short time) Up to 3 convertors For 4 or more converters	 0.6 0.5

Appendix B – Modelling of Network Elements Based on CIGRE Guideline

B.1 Generator Model

According to the CIGRE guideline WG CC02 [22], synchronous generator harmonic impedance is modelled as a function of harmonic order h^{th}, machine sub-transient reactance X_d'' and by resistance at the fundamental frequency.

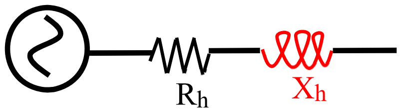


Figure B.1 – Synchronous Generator Harmonic Impedance Model

$R_1 = 0.1.X_d''$ (Corresponding to a subtransient time constant of 32 ms)

At any harmonic number h, the reactance is presented as: $X_h = h.X_d''$

The Skin effect is taken into account by considering: $R_h = R_1.\sqrt{h}$

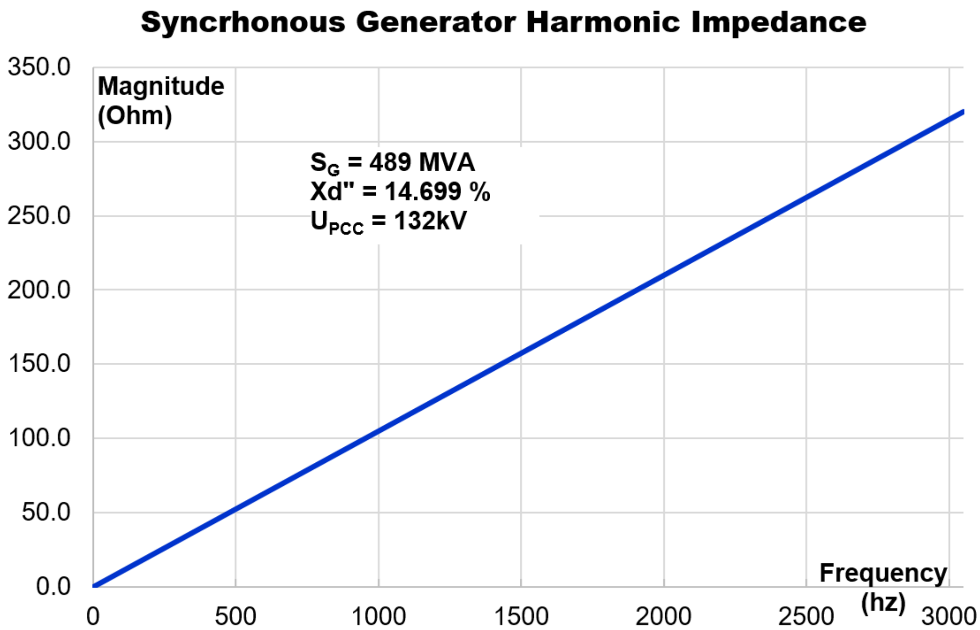
$$Z_{SyncGen}(h) = R_1\sqrt{h} + j.h.X_d'' = X_d''(0.1\sqrt{h} + j.h) \tag{B.1}$$

R_1: Generator resistance at the fundamental frequency

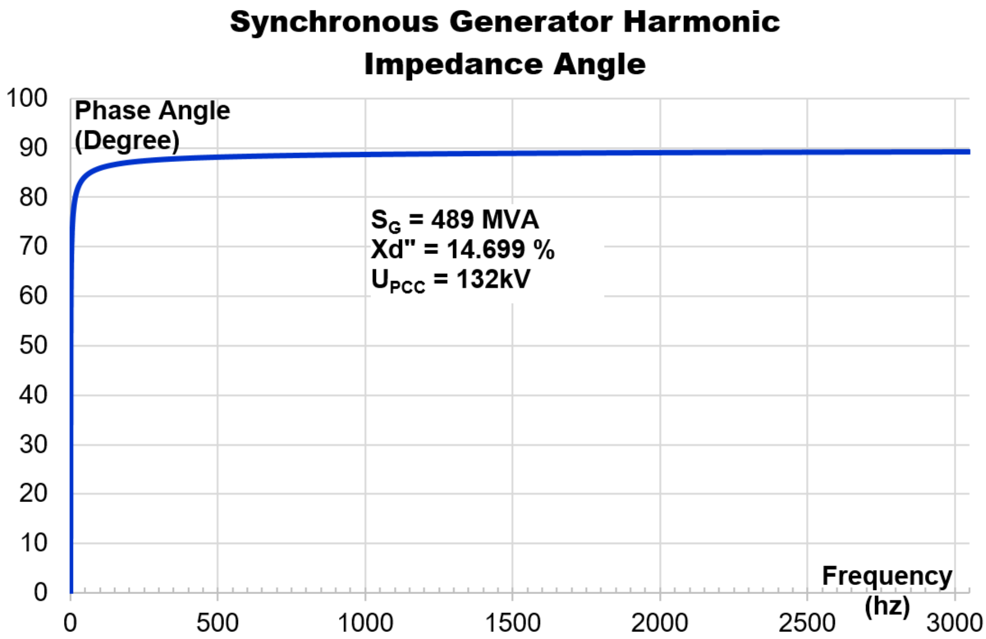
X_d'': Generator sub-transient reactance

h: Harmonic order

The harmonic impedance of a synchronous generator, which is used in several case studies in this thesis, was modelled as per CIGRE guideline as shown below:



(a). Generator Harmonic Impedance Magnitude



(b). Generator Harmonic Impedance Angle

Figure B.2 – Characteristics of Synchronous Generator Harmonic Impedances – (132 kV, 489 MVA, Xd" = 14.699%)

B.2 Transformers

The transformer is represented by an impedance Z_h made up from a resistance R_S in series with an assembly consisting of a reactance X_h in parallel with a resistance R_P.

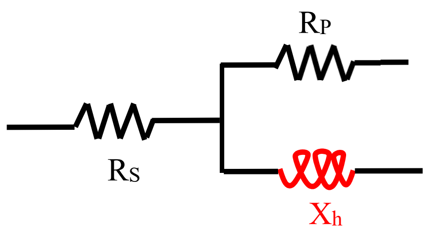


Figure B.3 – Transformer Harmonic Impedance Model

The reactance X_1 corresponds to the leakage reactance of the transformer at the fundamental frequency.

$$X_h(h) = h.X_1 \tag{B.2}$$

Resistance R_S and R_P are the series and parallel resistances:

$$R_S = \frac{X_1}{\tan(\varphi_1)} \tag{B.3}$$

$$R_P = 10.X_1.\tan(\varphi_1) \tag{B.4}$$

$$\tan(\varphi_1) = \exp[0.693 + 0.796.\ln(S_n) - 0.0421.\left(ln(S_n)\right)^2] \tag{B.5}$$

Furthermore, it is possible to take into account the different nominal voltages for the network and the transformer.

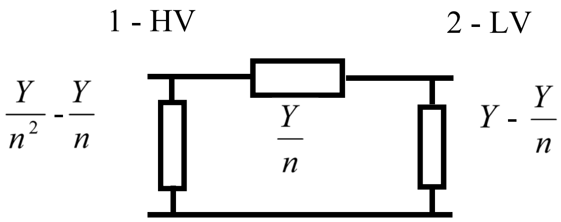


Figure B.4 – Transformer Harmonic Admittance Model

$$n = \frac{U_{n1\_TFMR}}{U_{n2\_TFMR}} \cdot \frac{U_{n2\_Network}}{U_{n1\_Network}} \tag{B.6}$$

S_n: Transformer rated power.

n: Reduced transformer ratio. In most cases $n = 1$ if the effect of the tap changer is not included in the calculation (n will be different to 1 if the effect of the tap changer is included).

U_{n1_TFMR}: Rated voltage of transformer at its HV side.

U_{n2_TFMR}: Rated voltage of transformer at its LV side.

$U_{n1\_Network}$: Nominal voltage of the network at the HV side.

$U_{n2\_Network}$: Nominal voltage of the network at the LV side.

$$Z_{Tfmr}(h) = R_S + \frac{R_P.(j.X(h))}{R_P + j.X(h)} = \frac{R_S.R_P + j.X(h).(R_S + R_P)}{R_P + j.X(h)} \tag{B.7}$$

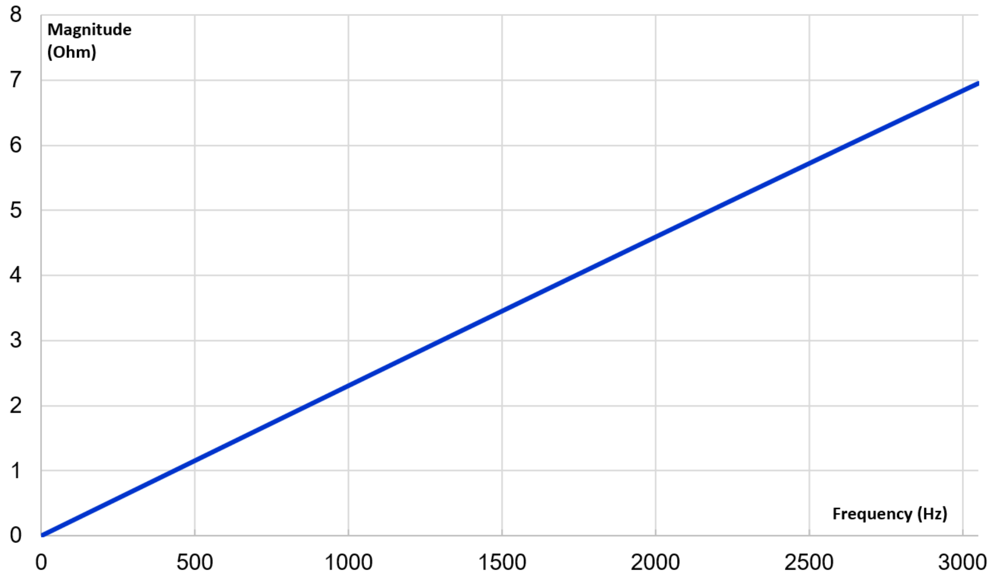
Transformer impedance $Z_{Tfmr}(h)$ is converted to the equivalent admittance

$$Y_{Tfmr}(h) = \frac{1}{Z_{Tfmr}(h)} \tag{B.8}$$

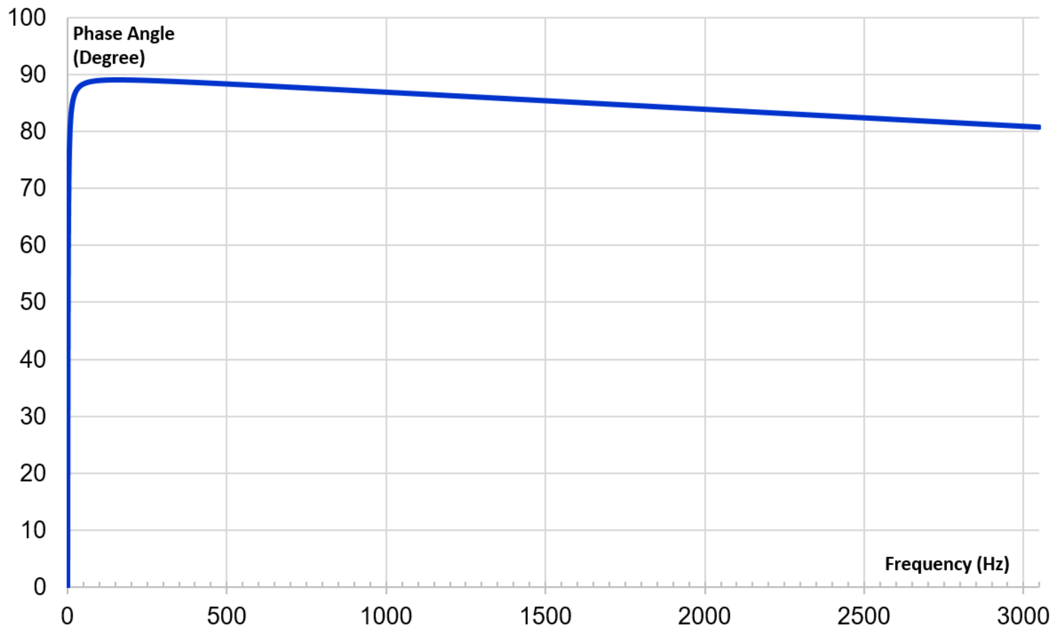
$$Transformer\ HV - LV\ Admittance = \left(\frac{Y(h)}{n}\right) + \left(\frac{Y(h)}{n^2} - \frac{Y(h)}{n}\right) = \left(\frac{Y(h)}{n^2}\right) \tag{B.9}$$

Similarly, Transformer Admittance between LV to HV bus is

$$Transformer\ LV - HV = \left(\frac{Y(h)}{n}\right) + \left(Y(h) - \frac{Y(h)}{n}\right) = Y(h) \tag{B.10}$$



(a). Transformer Harmonic Impedance Magnitude



(b). Transformer Harmonic Impedance Angle

Figure B.5 – Characteristics of Power Transformer Harmonic Impedances – (132/14.1 kV 150 MVA, Z_0 = 11.55%)

B.3 Transmission Lines

Although the classical simple π-equivalent circuit (with R-L series – and C parallel elements) is often sufficient, the more exact one is easily obtained from:

$$Z = R_h + j.h.X \tag{B.11}$$

$$Y = j.h.\omega.C \tag{B.12}$$

$$Z' = \frac{Z.sinh\left(\sqrt{Y.Z}\right)}{\sqrt{Y.Z}} \tag{B.13}$$

$$Y'_{Hyper\_Line\_Ser} = \frac{1}{Z'} \tag{B.14}$$

$$\frac{Y\prime}{2} = Y.\frac{Tanh\left(\frac{\sqrt{Y.Z}}{2}\right)}{\sqrt{Y.Z}} \tag{B.15}$$

$$Y'_{HyperOn2\_Line\_Shunt} = \frac{Y\prime}{2} = Y.\frac{Tanh\left(\frac{\sqrt{Y.Z}}{2}\right)}{\sqrt{Y.Z}} \tag{B.16}$$

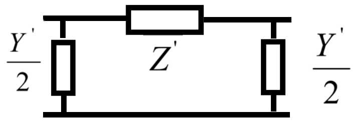


Figure B.6 – Transmission Line Harmonic Admittance Model

Take into account the skin effect of line length ℓ (km)

$$R_{dc} = \frac{R_1 - 0.004398\,.\,l}{0.938} \tag{B.17}$$

$$x = 0.3545\sqrt{\frac{h}{\frac{R_{dc}}{l}}} \tag{B.18}$$

For $x \leq 2.4$

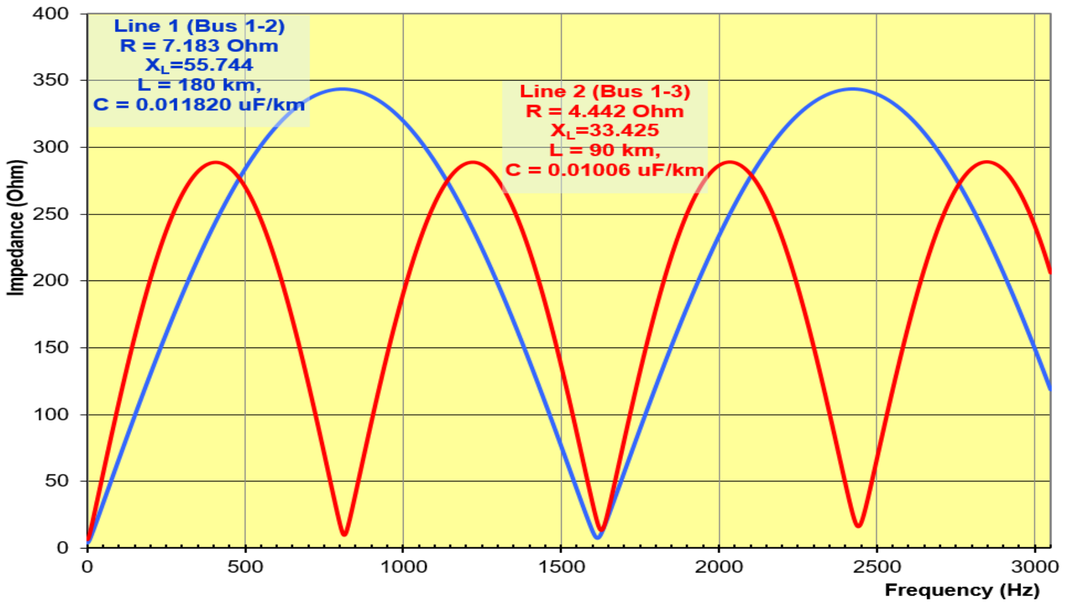
$$R_h = R_{dc}(0.035\,.\,x^2 + 0.938) \tag{B.19}$$

For $x > 2.4$

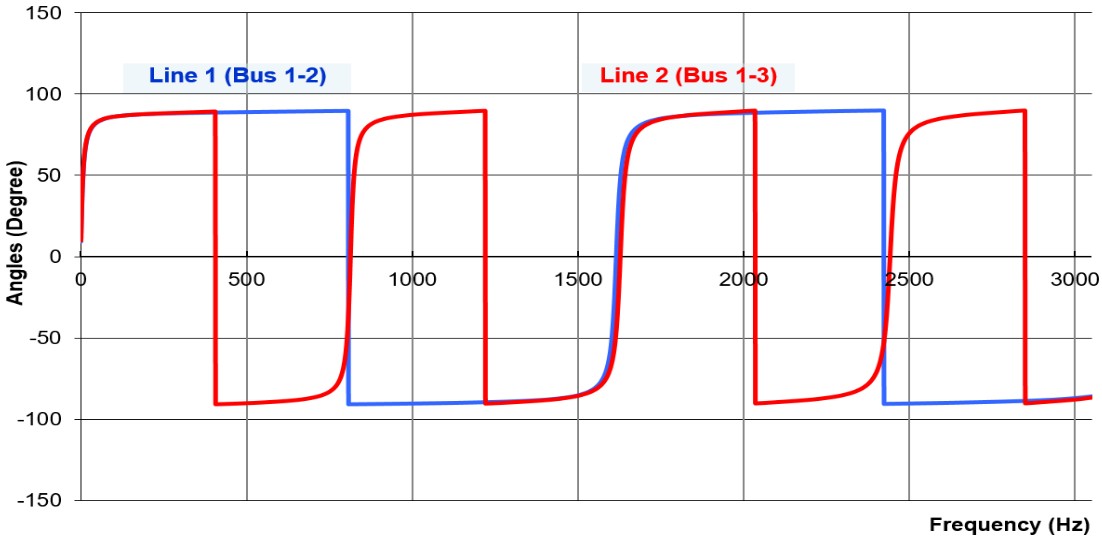
$$R_h = R_{dc}(0.35\,.x + 0.3) \tag{B.20}$$

R_1: Transmission Line Resistance at the fundamental frequency.

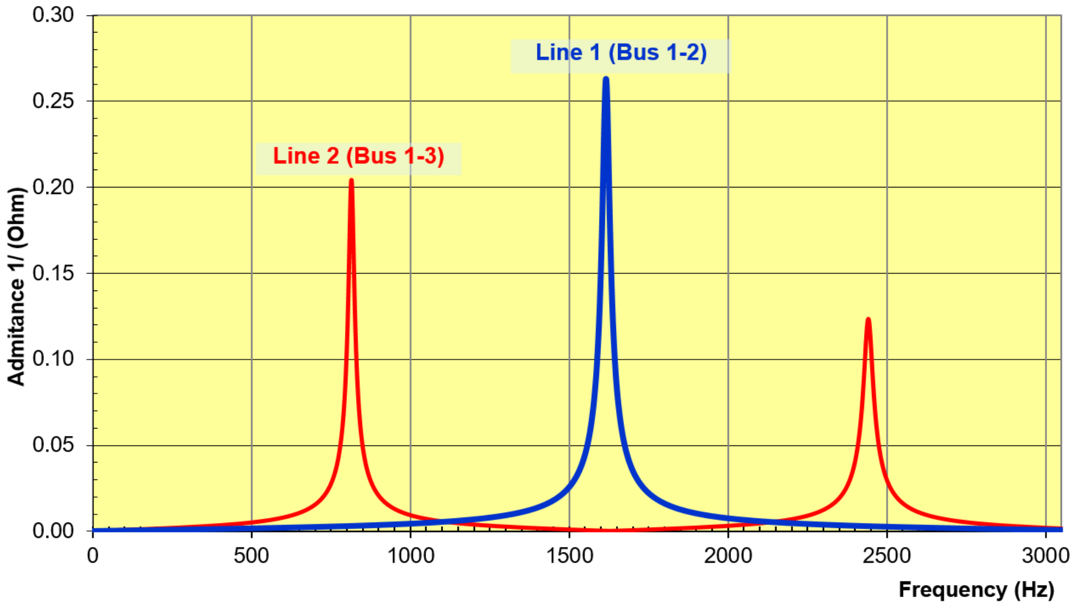
Impedances of transmission lines appear as multiple resonances over the frequency spectrum and its shunt capacitances would be the key contributor to sharp rises of self-impedances at both ends of the line.



(a). Transmission Line Series Impedance Magnitude



(b). Transmission Line Series Impedance Angle



(c). Transmission Line Shunt Admittance (Y'/2)

Figure B.7 – Characteristics of 180km versus 90km Transmission Lines Harmonic Impedances

B.4 Aggregated Loads

According to the CIGRE guideline [17], at least ten load models have been proposed in the literature and common practices, however, the following three load models below are considered as the most common among those performing harmonic studies. They are proposed to cover most cases:

B.4.1 CIGRE Load Model

Over a frequency range corresponding to harmonics between the 5th and 20th approximately, the loads can be represented by a reactance X_s in series with a resistance R, this assembly being connected in parallel with a reactance X_p such that

$$R = \frac{U_{n\_network}^2}{P_1} \quad (B.21)$$

$$X_S = 0.073\,.\,h\,.\,R \quad (B.22)$$

$$X_P = \frac{h.R}{6.7\,.tan(\varphi_1) - 0.74} \quad (B.23)$$

$$\tan(\varphi_1) = \frac{Q_1}{P_1} \quad (B.24)$$

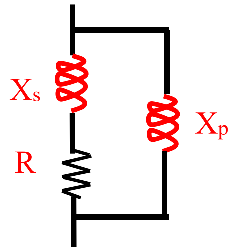


Figure B.8 – CIGRE Load Impedance Model

$U_{n\_network}$: Nominal voltage of the network.

P_1 Minimum active power of the load at the fundamental frequency under $U_{n\_network}$ in nominal network conditions, disregarding electronic motor loads.

Q_1 Reactive power of the load at the fundamental frequency under $U_{n\_network}$.

Aggregated linear load Harmonic Impedance and Admittance:

$$\boldsymbol{Z_{Load}(h)} = \frac{(\boldsymbol{R+j.X_S}) \times \boldsymbol{j.X_P}}{\boldsymbol{R+j.(X_S+X_P)}} \quad (B.25)$$

$$\boldsymbol{Y_{Load}(h)} = \frac{\boldsymbol{1}}{\boldsymbol{Z_{Load}(h)}} \quad (B.26)$$

B.4.2 R//L Load Model

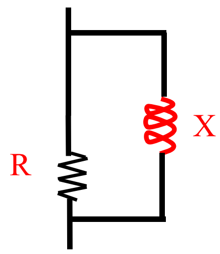


Figure B.9 – R//L Load Impedance Model

$$R = \frac{U_{n\_network}^2}{P_1} \quad (B.27)$$

$$X = h.\frac{U_{n\_network}^2}{Q_1} \quad (B.28)$$

B.4.3 Motor Load Model

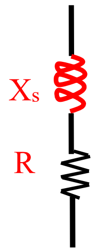


Figure B.10 – Motor Load Impedance Model

$$X_1 = \frac{U^2_{n\_network}}{S_{Start}} \tag{B.29}$$

S_{Start} Apparent power of the motor corresponding to the lock rotor situation.

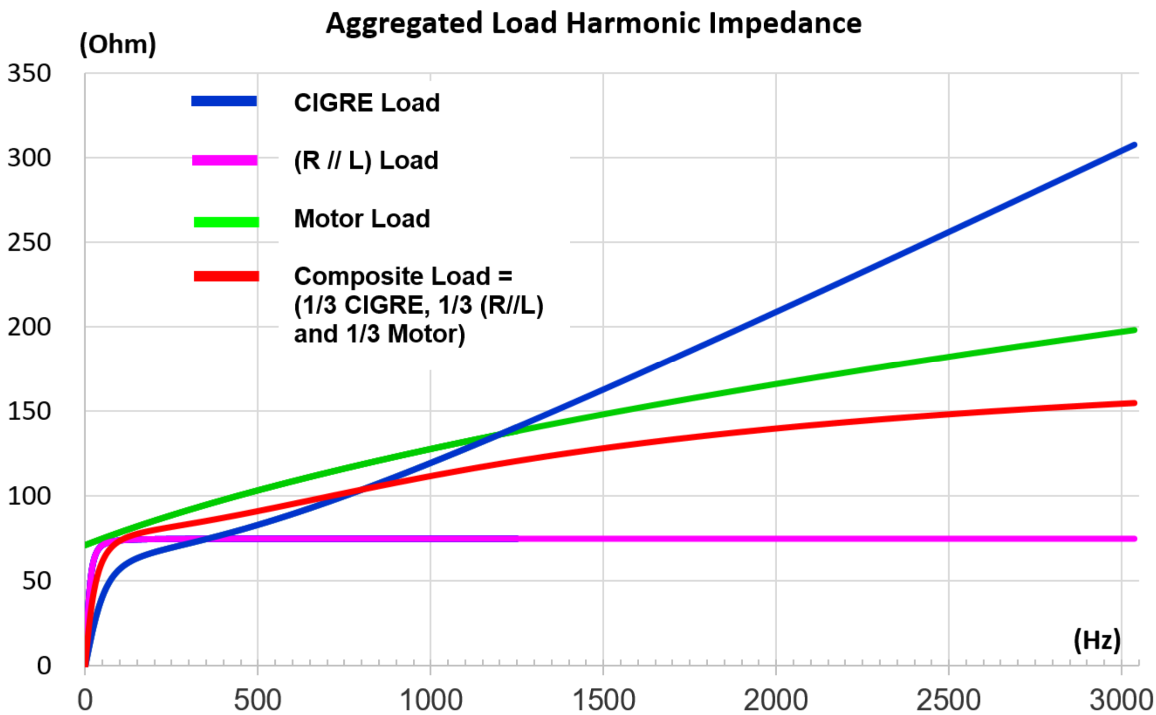
$$R_1 = \frac{X_1}{3} \tag{B.30}$$

(Corresponding to $\cos(\phi_{Start}) = 0.32$)

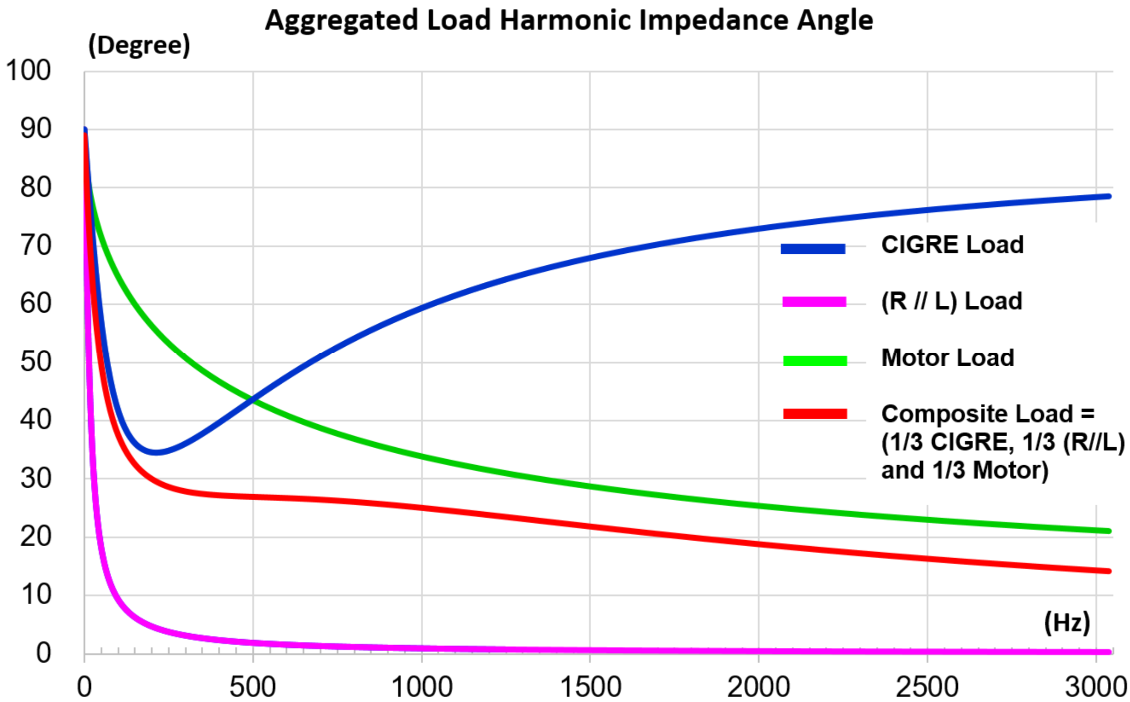
$$R = \sqrt{h}.R_1 \tag{B.31}$$

Skin effect is considered in the same way as for generators.

Load impedance characteristics appear as a reactive impedance that varies linearly with frequency as shown below.



(a). Harmonic Impedance Magnitudes of Different Load Models



(b). Harmonic Impedance Angles of Different Load Models

Figure B.11 – Characteristics of Harmonic Impedances of Load 11, 244.7 MVA, 0.95 PF Based on Three CIGRE Recommended Load Models

B.5 Shunt Capacitors/Passive Harmonic Filters

B.5.1 Harmonic filter with a damping resistor

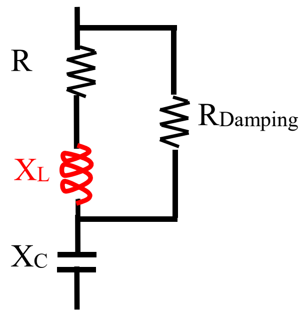


Figure B.12 – Harmonic Filter with Damping Resistor Impedance model

Harmonic filter capacitive reactance $$X_C(h) = \frac{1}{j.\omega_0.h.C} \quad \text{(B.32)}$$

Harmonic filter inductive reactance $$X_L(h) = j.\omega_0.h.L \quad \text{(B.33)}$$

Harmonic filter impedance $$Z_{Filter} = X_C(h) + \frac{(X_L(h)+R).R_{Damping}}{X_L(h)+R+R_{Damping}} \quad \text{(B.34)}$$

Harmonic filter admittance $$Y_{Filter}(h) = \frac{1}{Z_{Filter}(h)} \quad \text{(B.35)}$$

B.5.2 Harmonic filter (without damping resistor) and voltage support capacitor bank

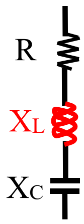


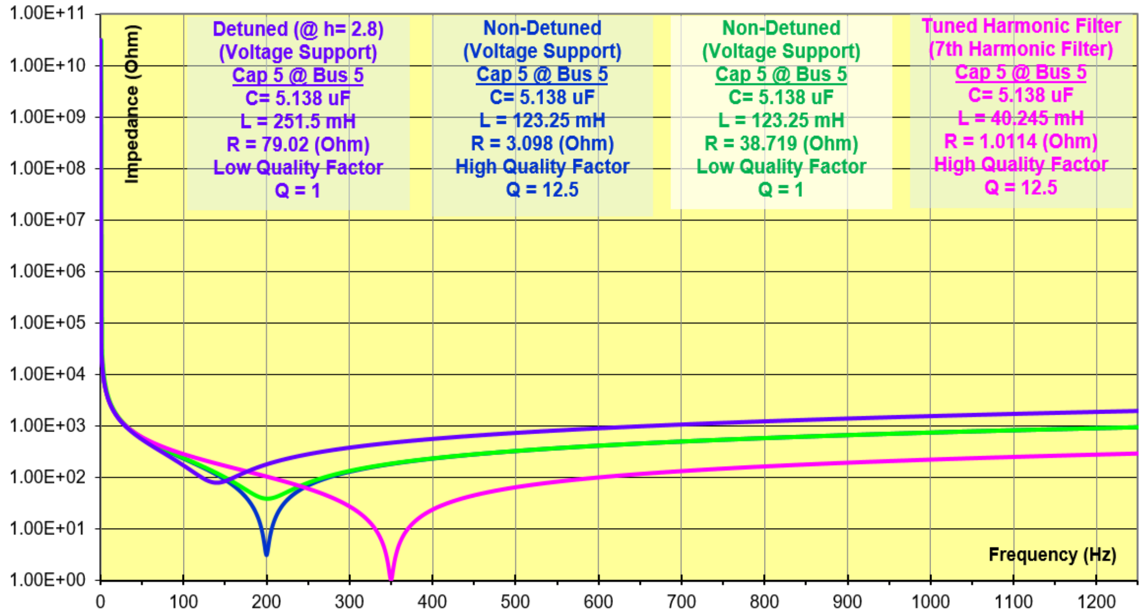
Figure B.13 – Voltage Support Capacitor Bank Impedance model

Capacitive reactance $$X_C(h) = \frac{1}{j.\omega_0.h.C} \quad \text{(B.36)}$$

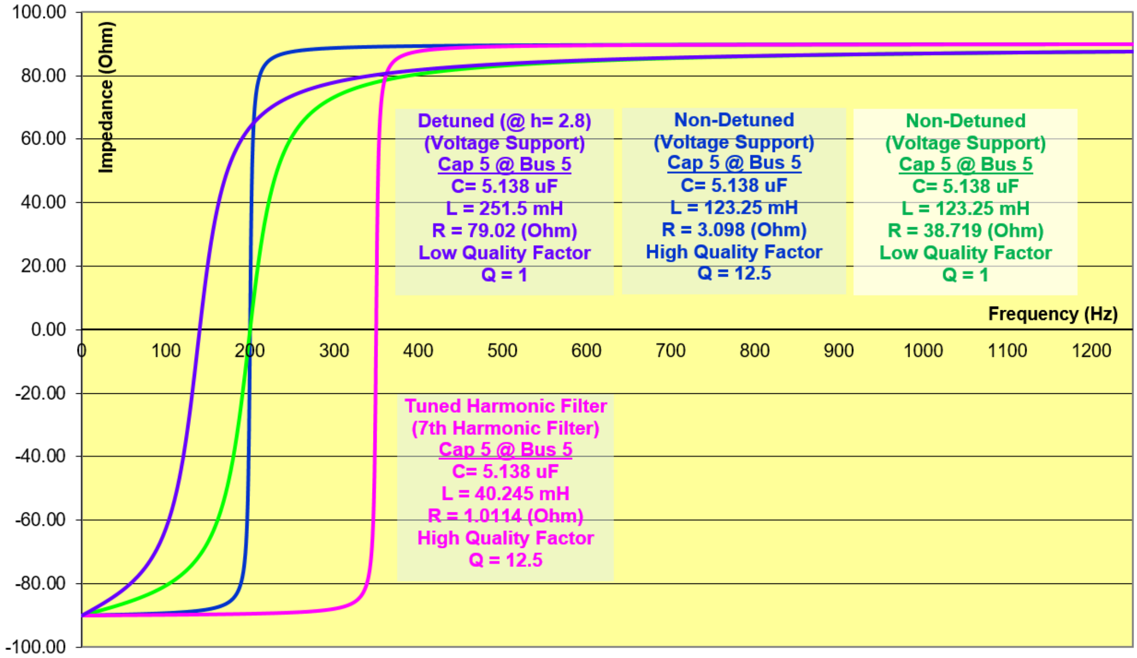
Inductive reactance $$X_L(h) = j.\omega_0.h.L \quad \text{(B.37)}$$

Harmonic filter / capacitor bank impedance

$$Z_{Filter\ Or\ Capbank}(h) = X_C(h) + X_L(h) + R \quad \text{(B.38)}$$



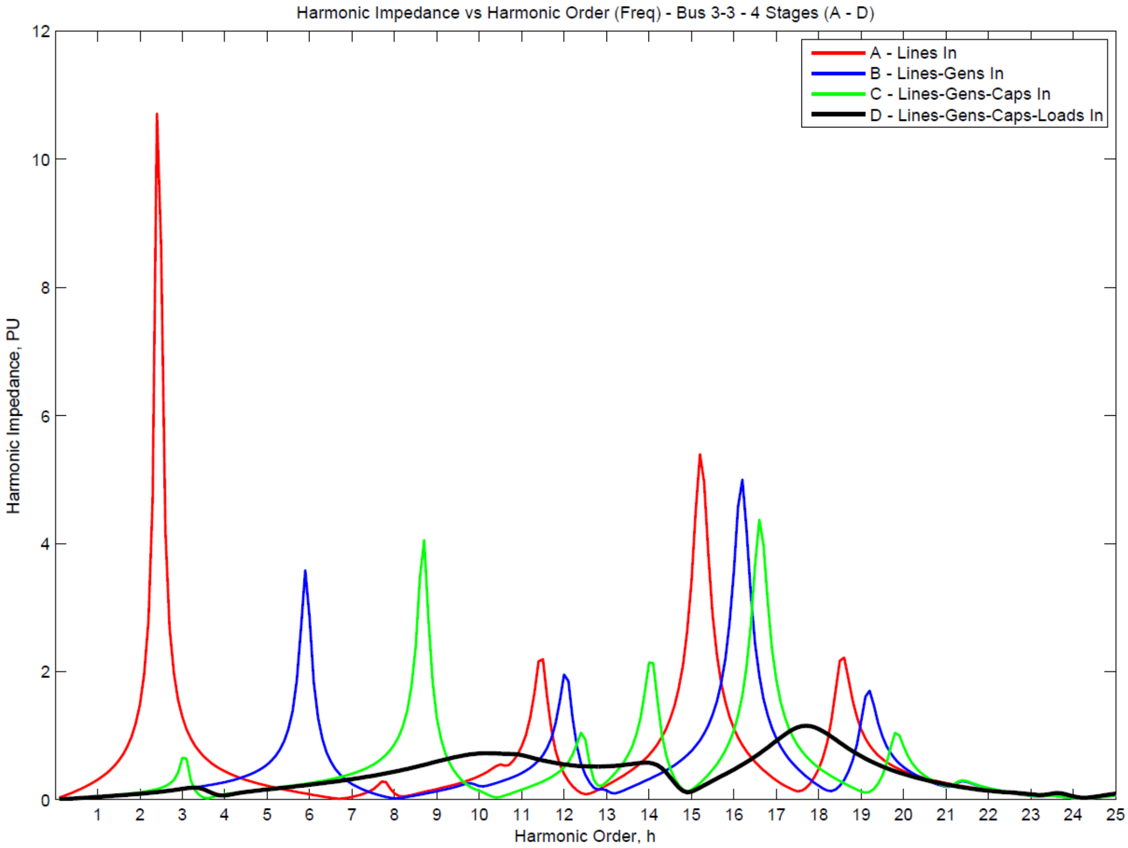
(a). Capacitor Bank Harmonic Impedance Magnitude



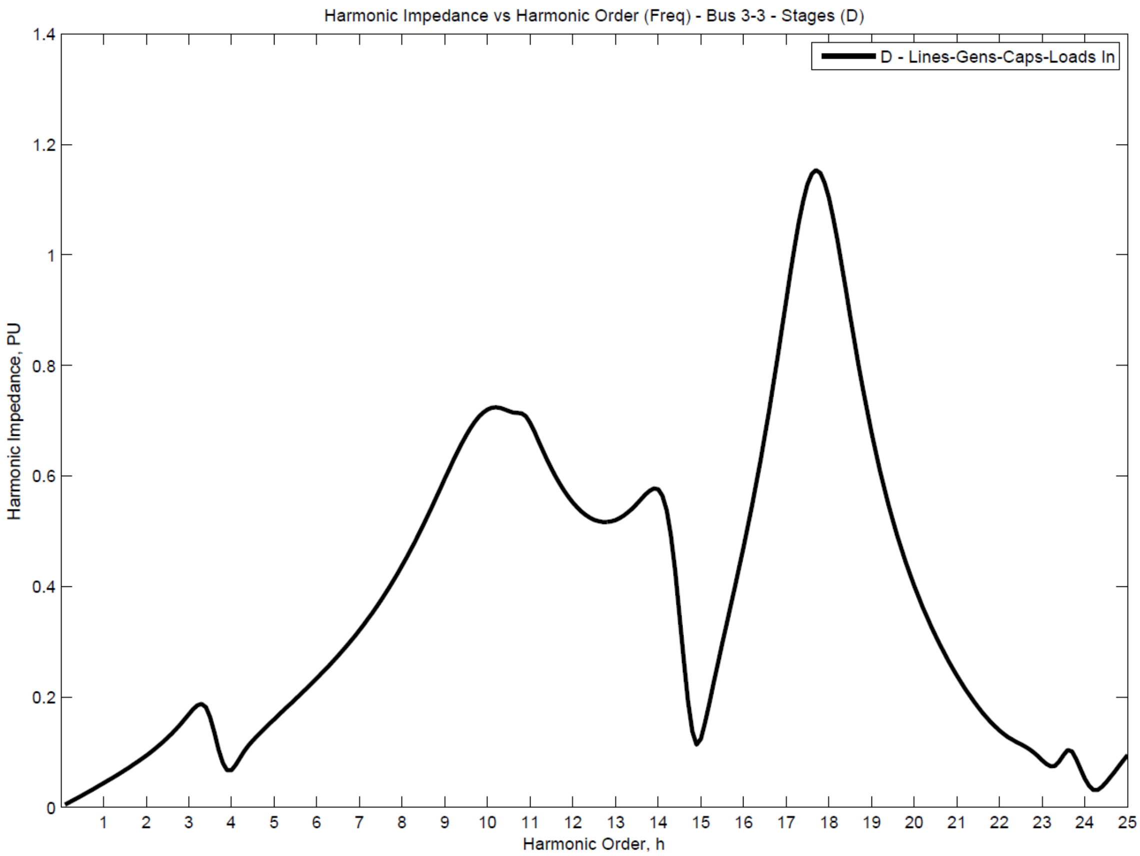
(b). Capacitor Bank Harmonic Impedance Phase Angles

Figure B.14 – Characteristics of Transmission Systems Capacitor Bank Harmonic Impedances

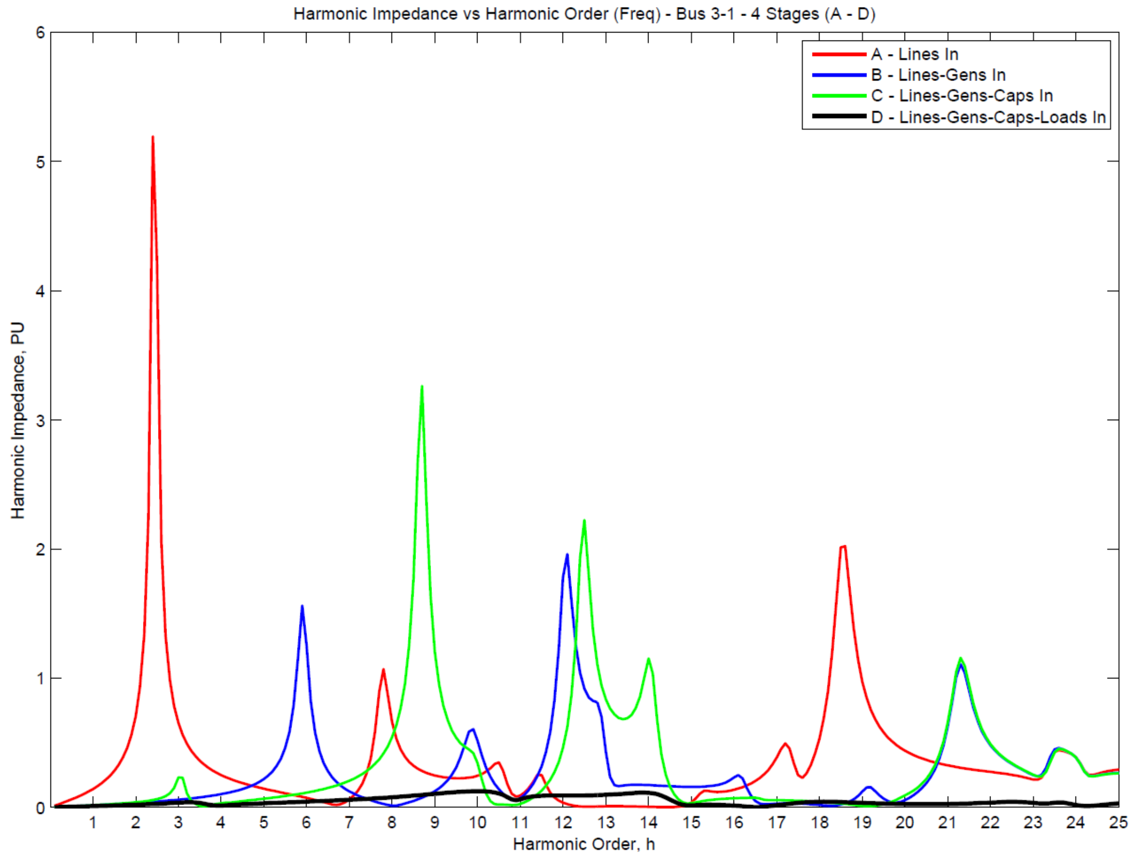
B.6 Harmonic Impedance Under Network Reconstruction Stages



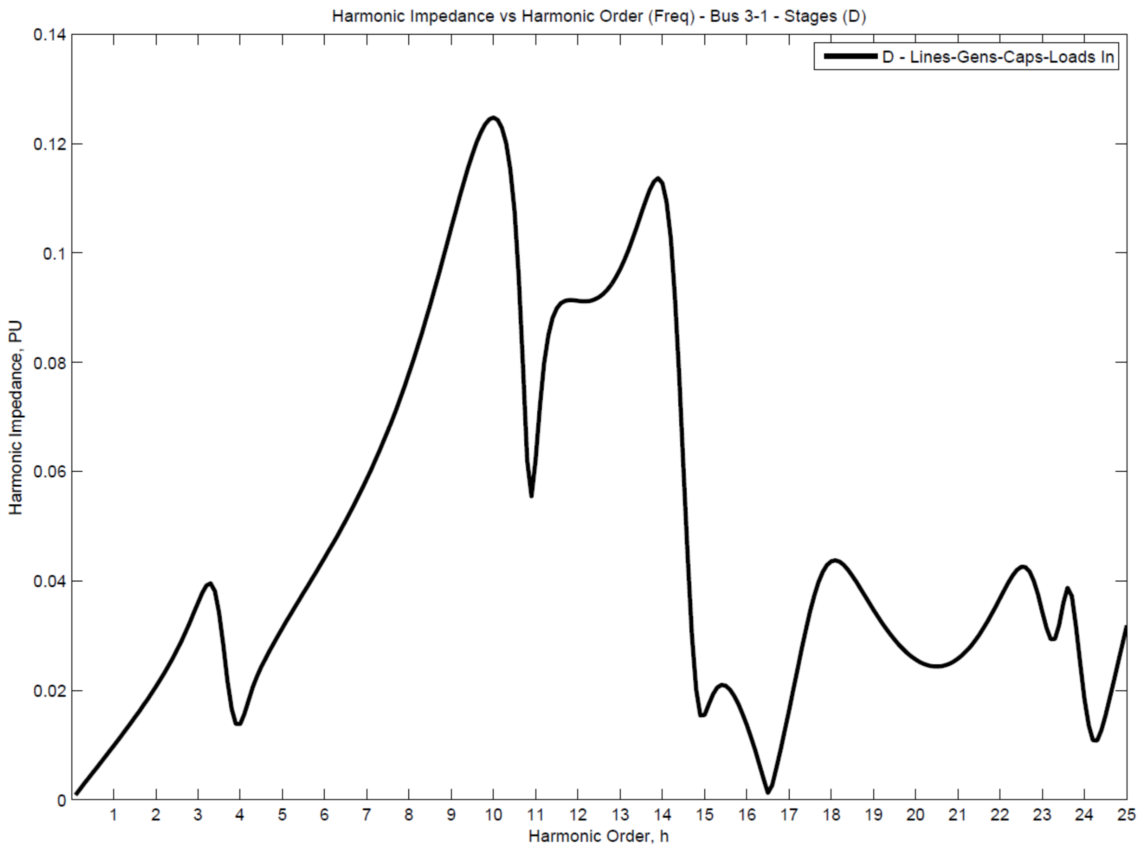
(a) Self-Impedance at Bus 3 – Stages (A-D) – Network Reconstruction Scenarios



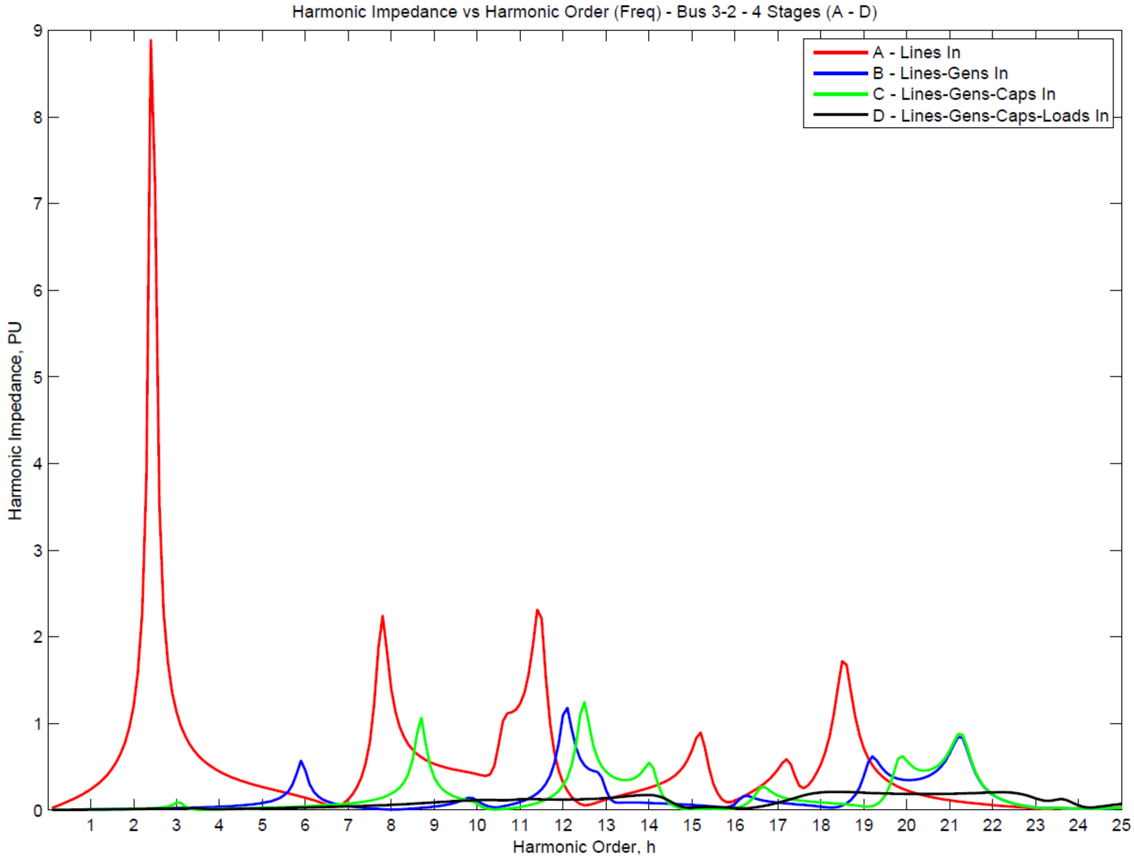
(b) Self-Impedance at Bus 3 – Stage (D) Only – Network Reconstruction Scenarios



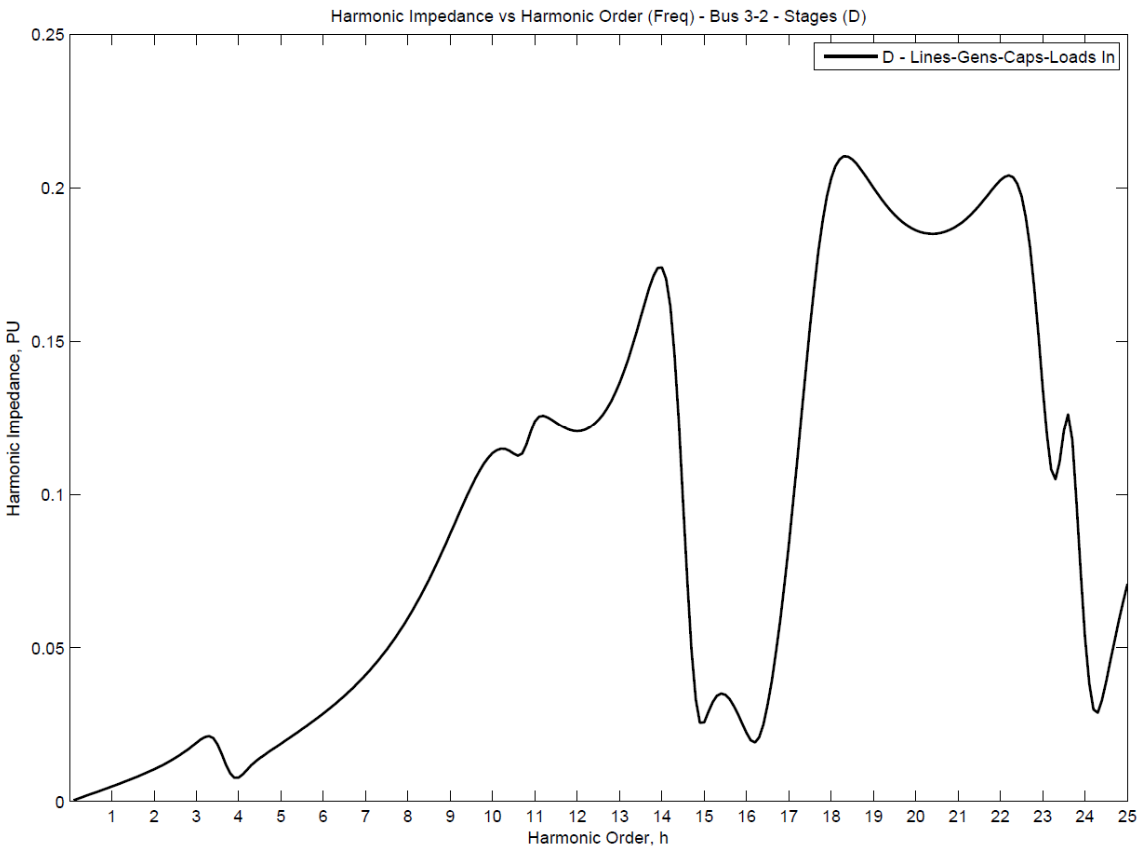
(c) Mutual Impedance between Bus 3 and Bus 1 – Stages (A-D) – Network Reconstruction Scenarios



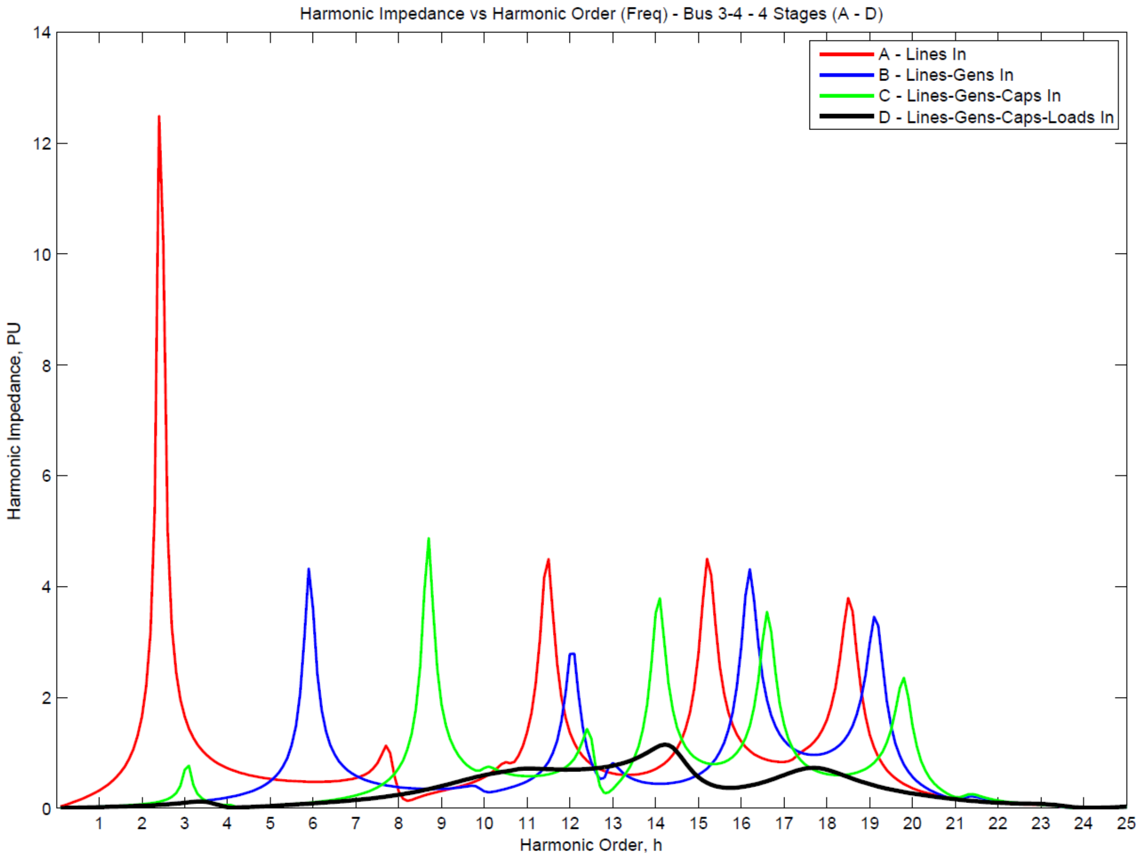
(d) Mutual Impedance between Bus 3 and Bus 1 – Stages (D) – Network Reconstruction Scenarios



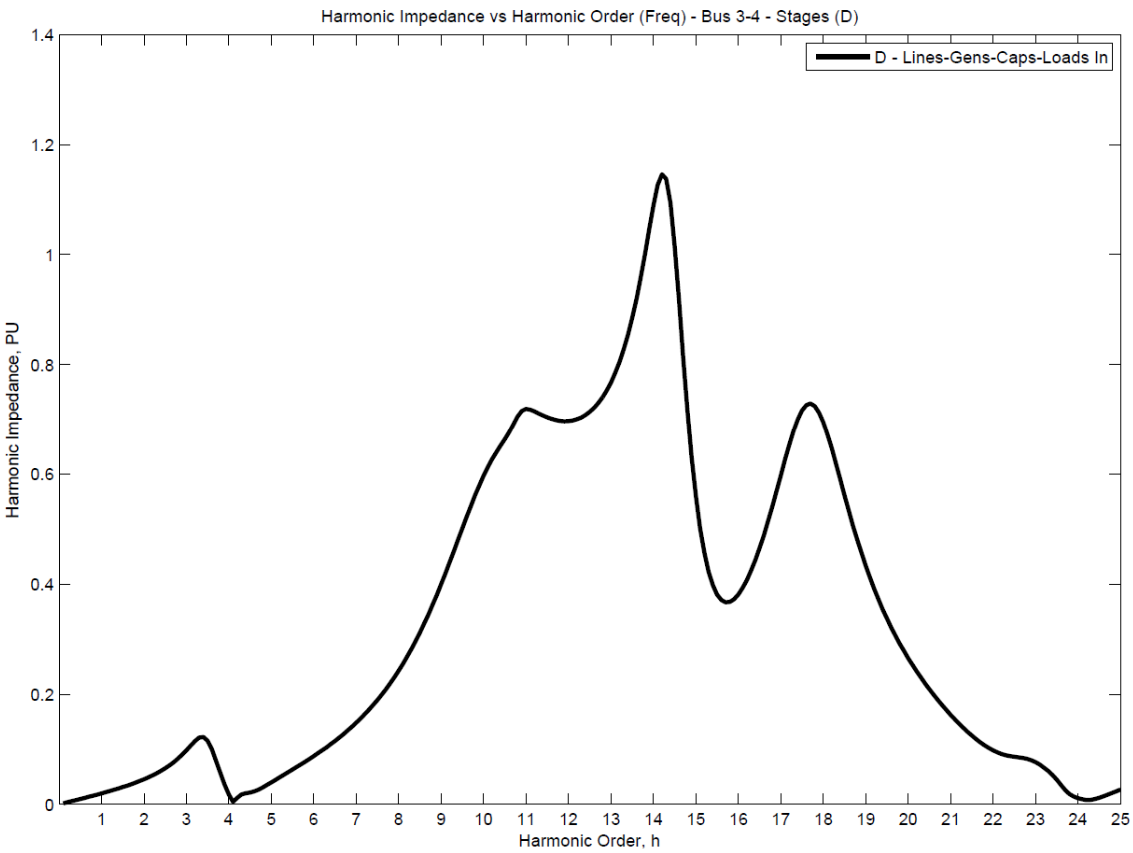
(e) Mutual Impedance between Bus 3 and Bus 2 – Stages (A-D) – Network Reconstruction Scenarios



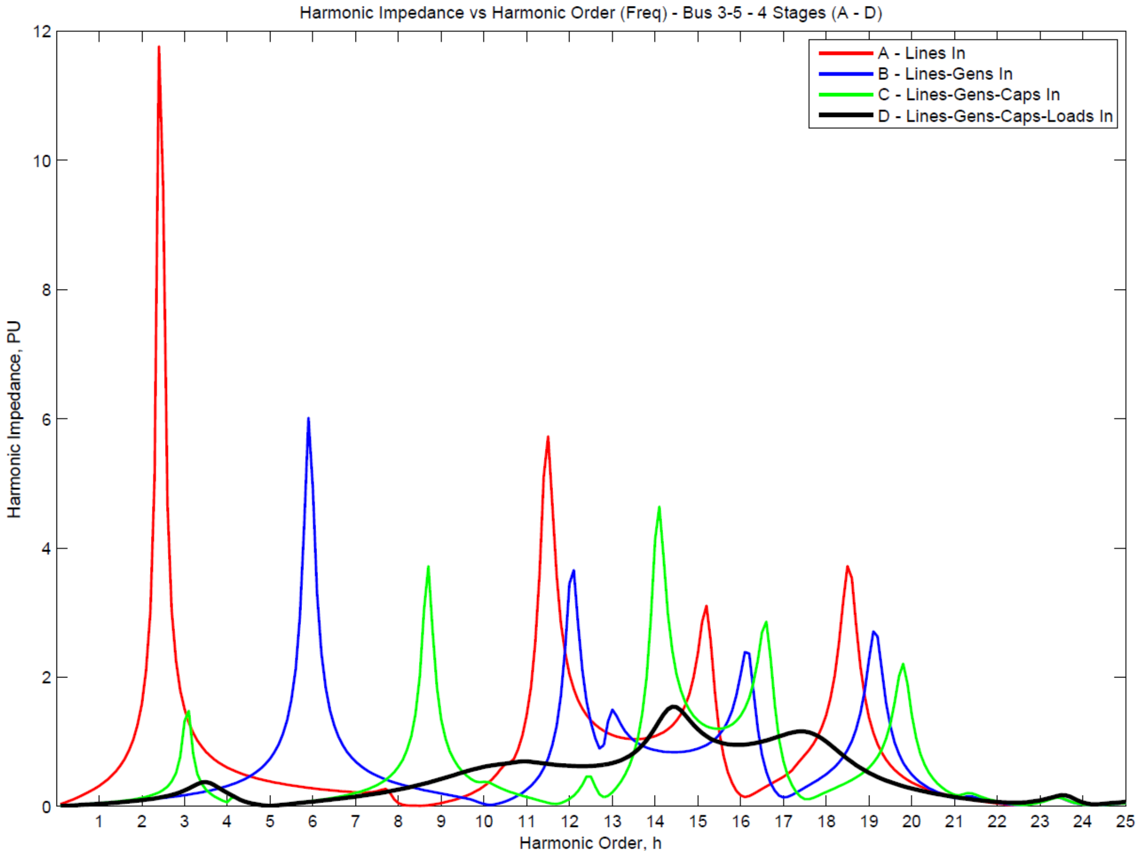
(f) Mutual Impedance between Bus 3 and Bus 2 – Stage (D) – Network Reconstruction Scenarios



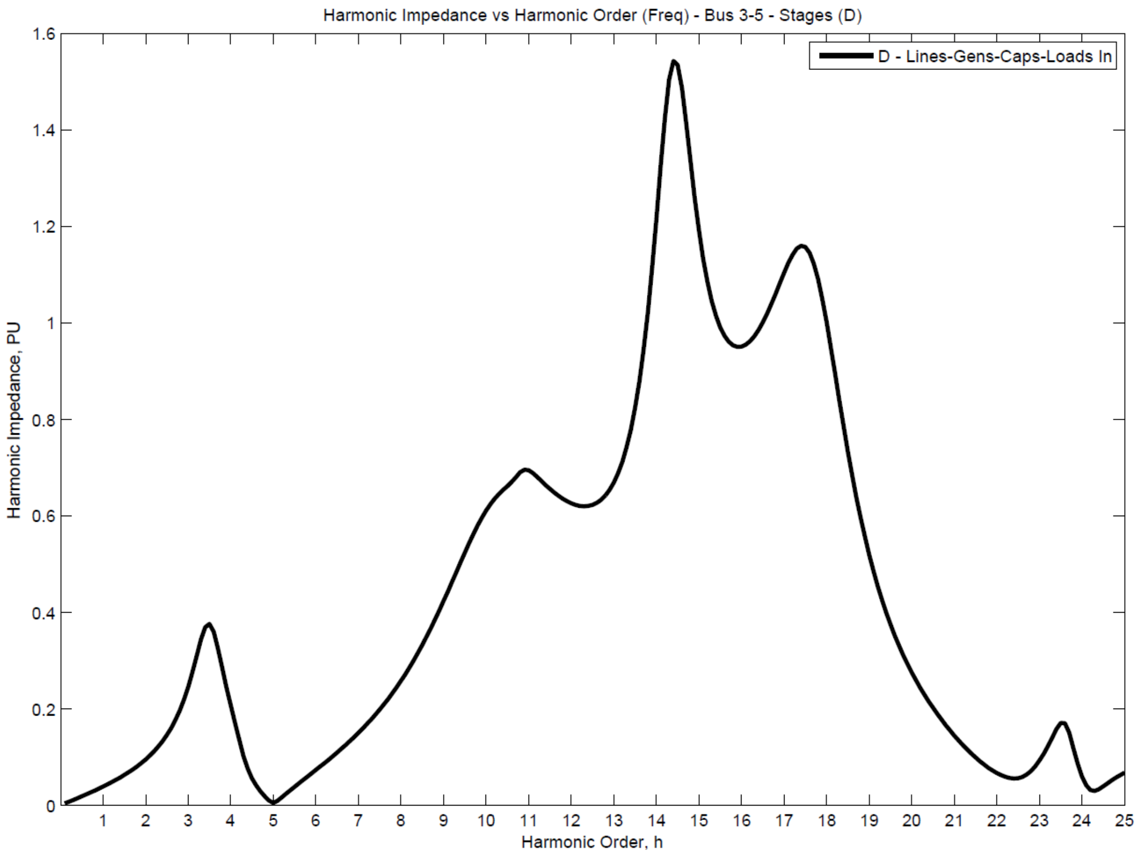
(g) Mutual Impedance between Bus 3 and Bus 4 – Stage (A - D) – Network Reconstruction Scenarios



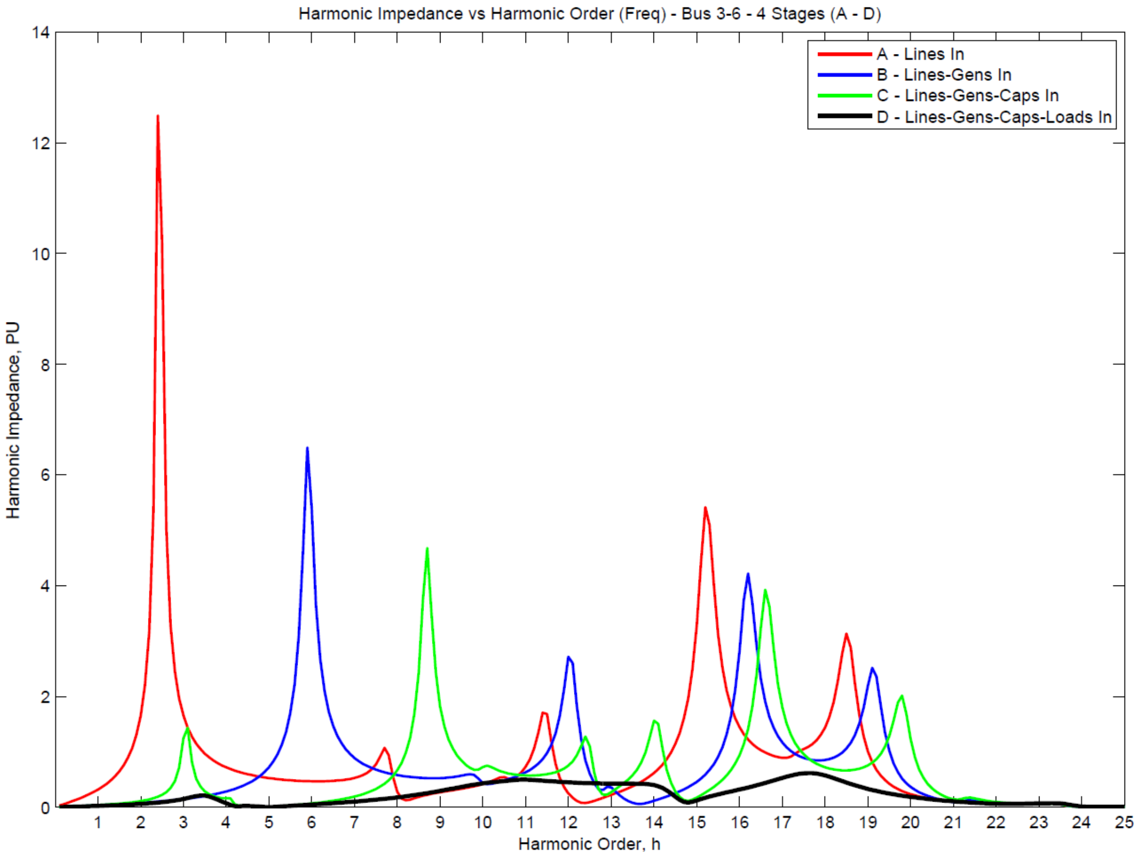
(h) Mutual Impedance between Bus 3 and Bus 4 – Stage (D) – Network Reconstruction Scenarios



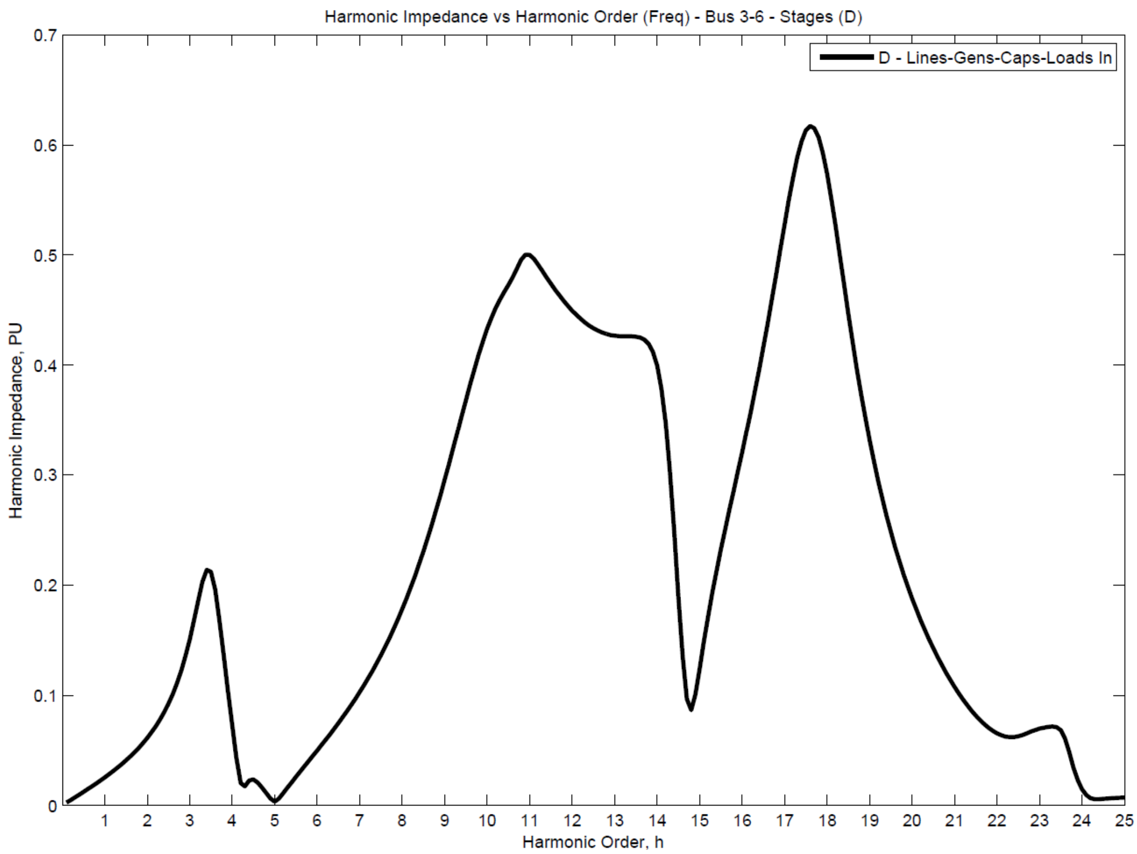
(i) Mutual Impedance between Bus 3 and Bus 5 – Stage (A - D) – Network Reconstruction Scenarios



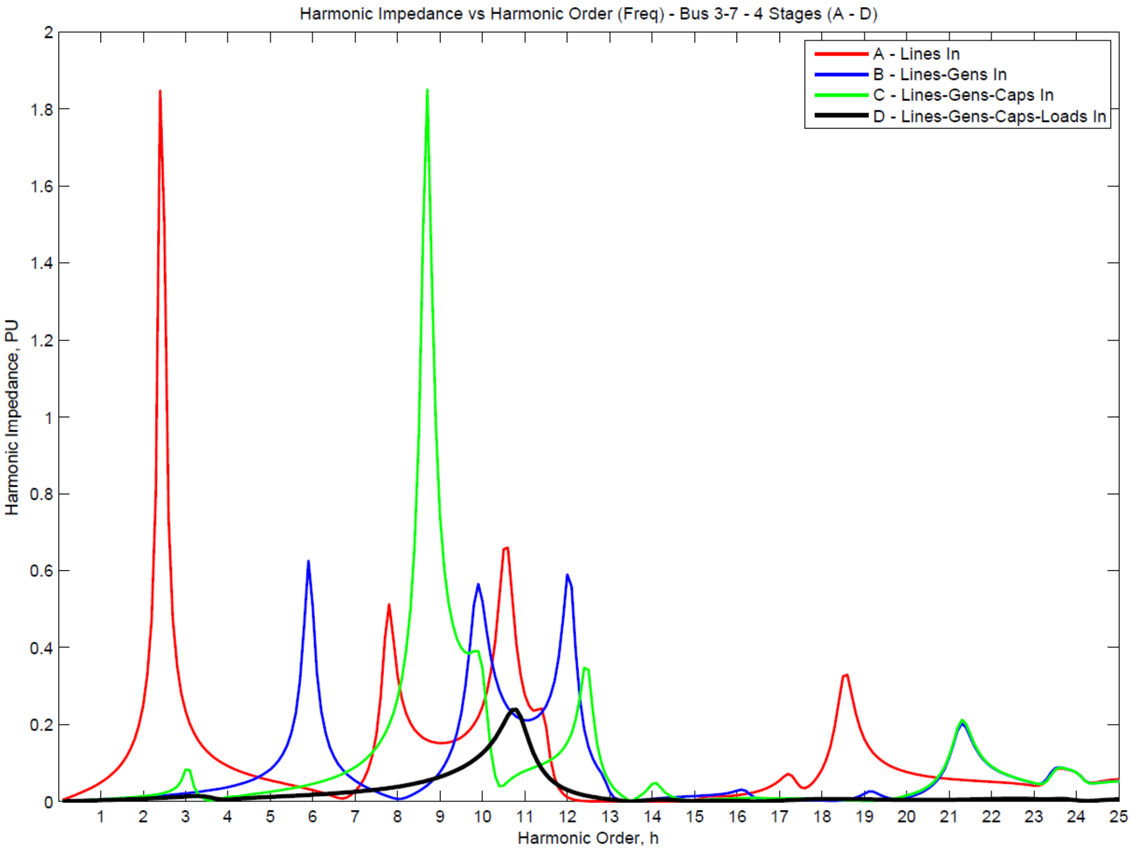
(j) Mutual Impedance between Bus 3 and Bus 5 – Stage (D) – Network Reconstruction Scenarios



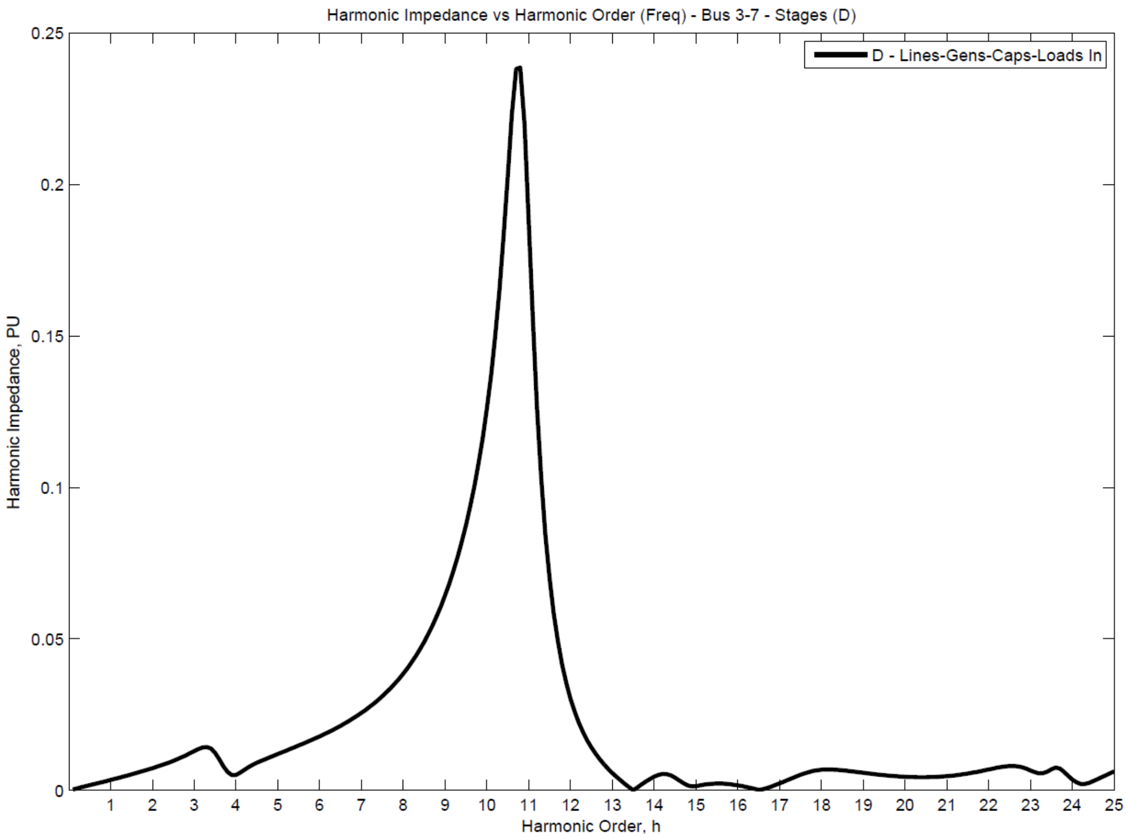
(k) Mutual Impedance between Bus 3 and Bus 6 – Stage (A - D) – Network Reconstruction Scenarios



(l) Mutual Impedance between Bus 3 and Bus 6 – Stage (D) – Network Reconstruction Scenarios



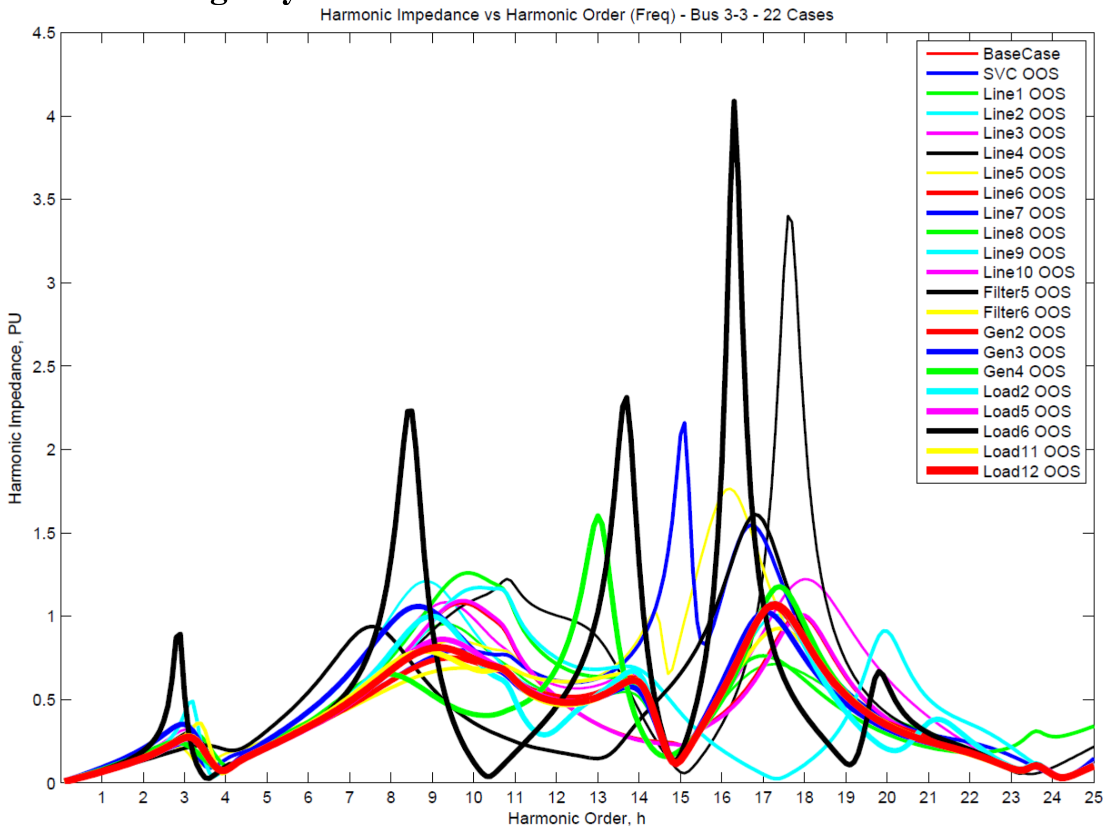
(m) Mutual Impedance between Bus 3 and Bus 7 – Stage (A-D) – Network Reconstruction Scenarios



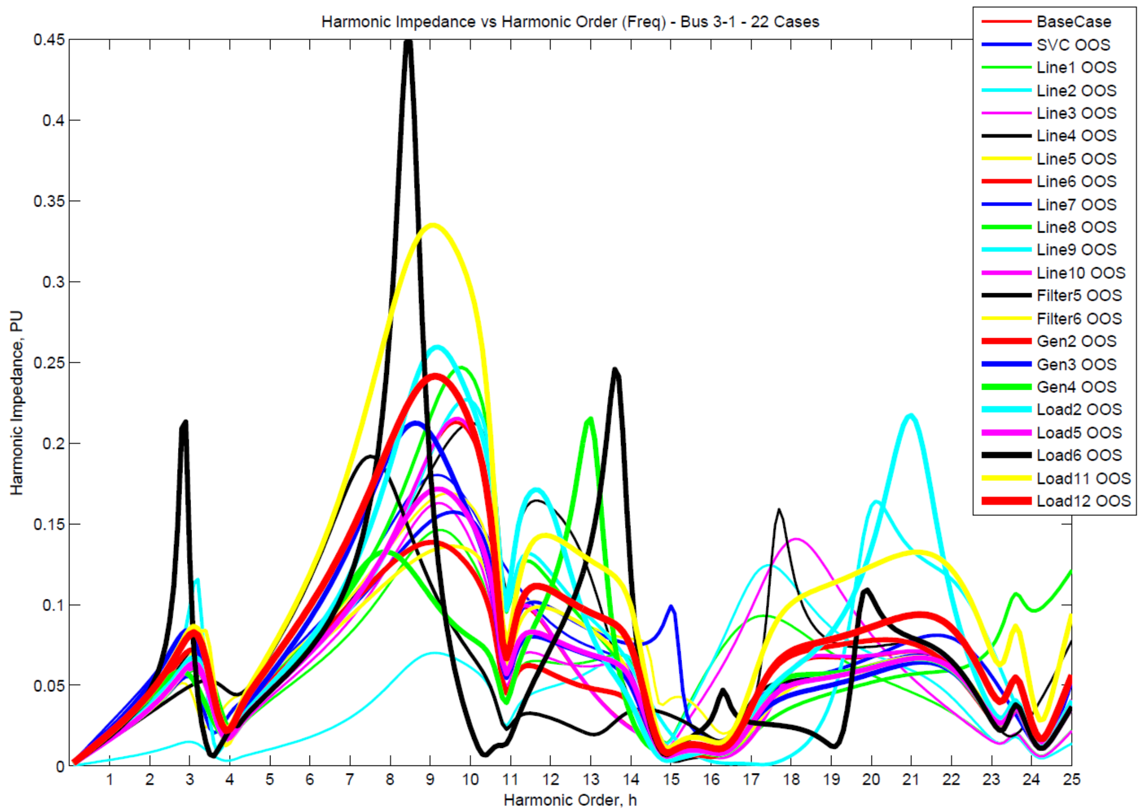
(n) Mutual Impedance between Bus 3 and Bus 7 – Stage (D) – Network Reconstruction Scenarios

Figure B.15 – Harmonic Impedances ($Z_{i,j}(h)$) at Bus 3 - Reconstruction Network Scenarios

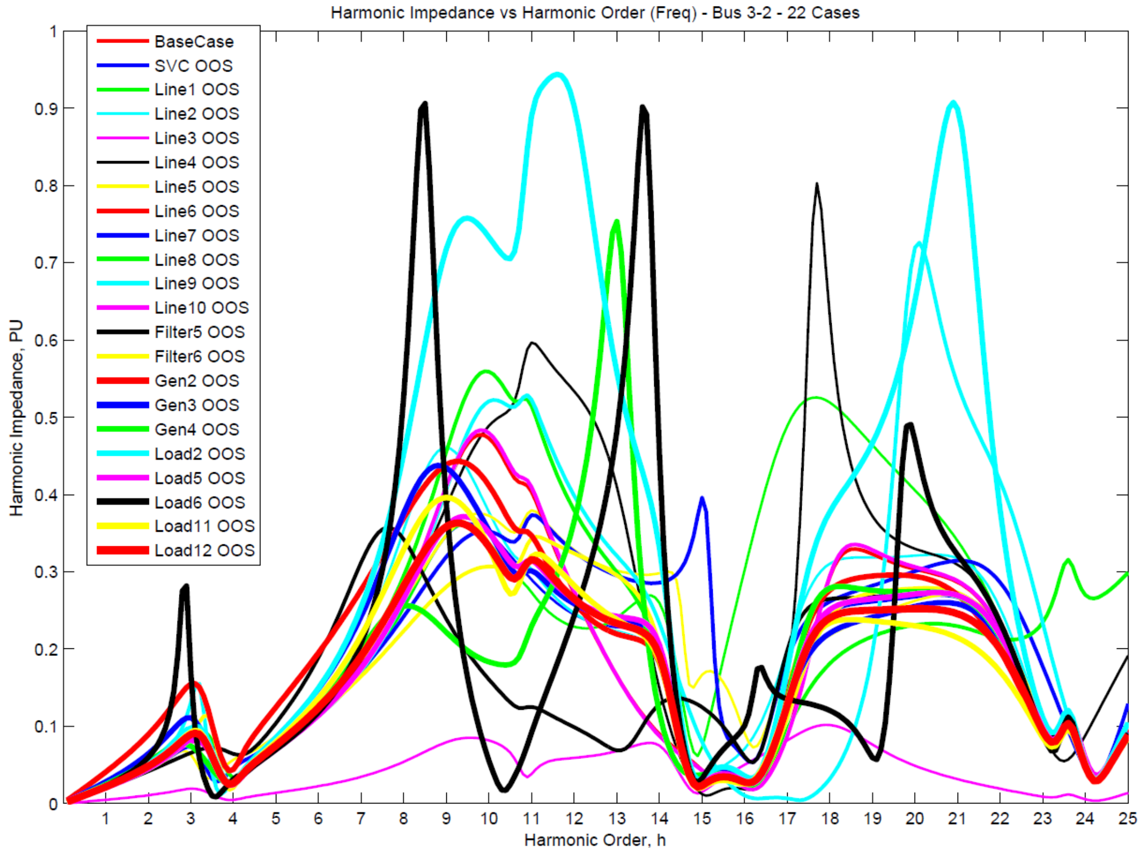
B.7 Harmonic Impedance under (N-1) Practical Network Contingency Scenarios



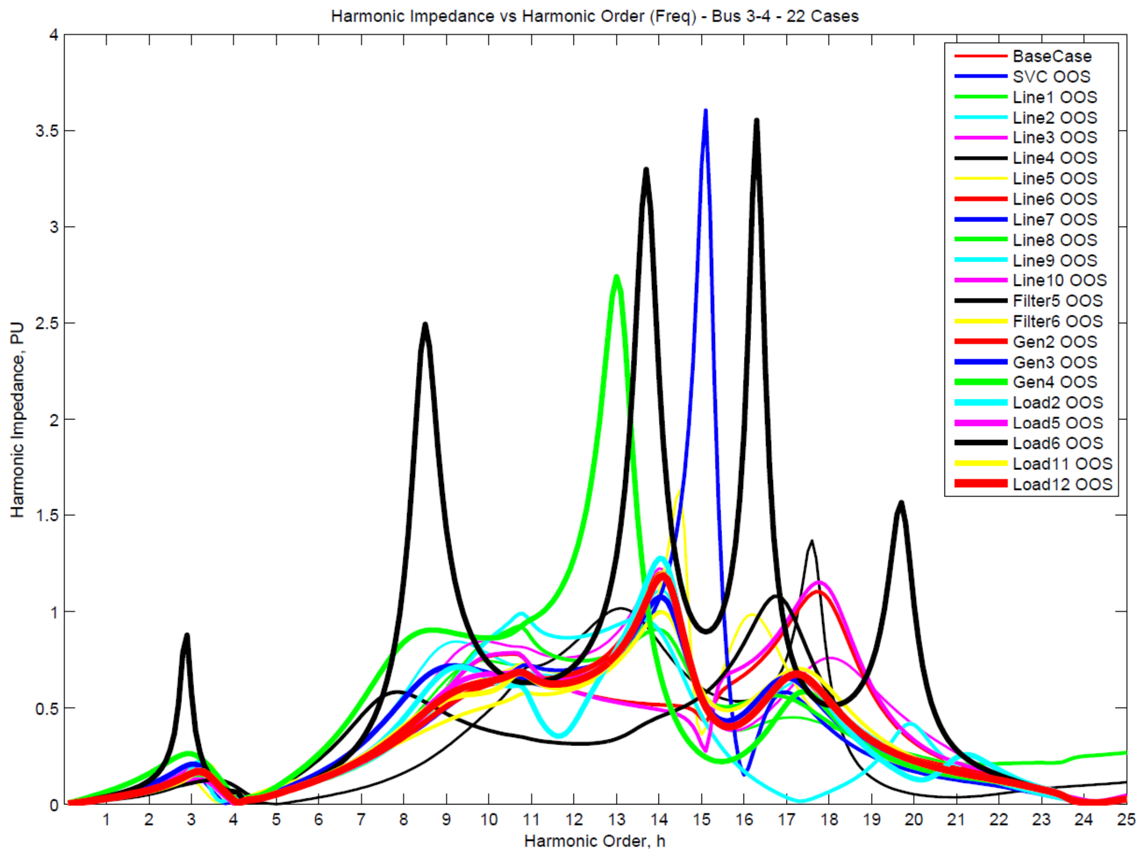
(a). Self-Impedance ($Z_{33}(h)$) at Bus 3 – 22 Network Scenarios (N-1)



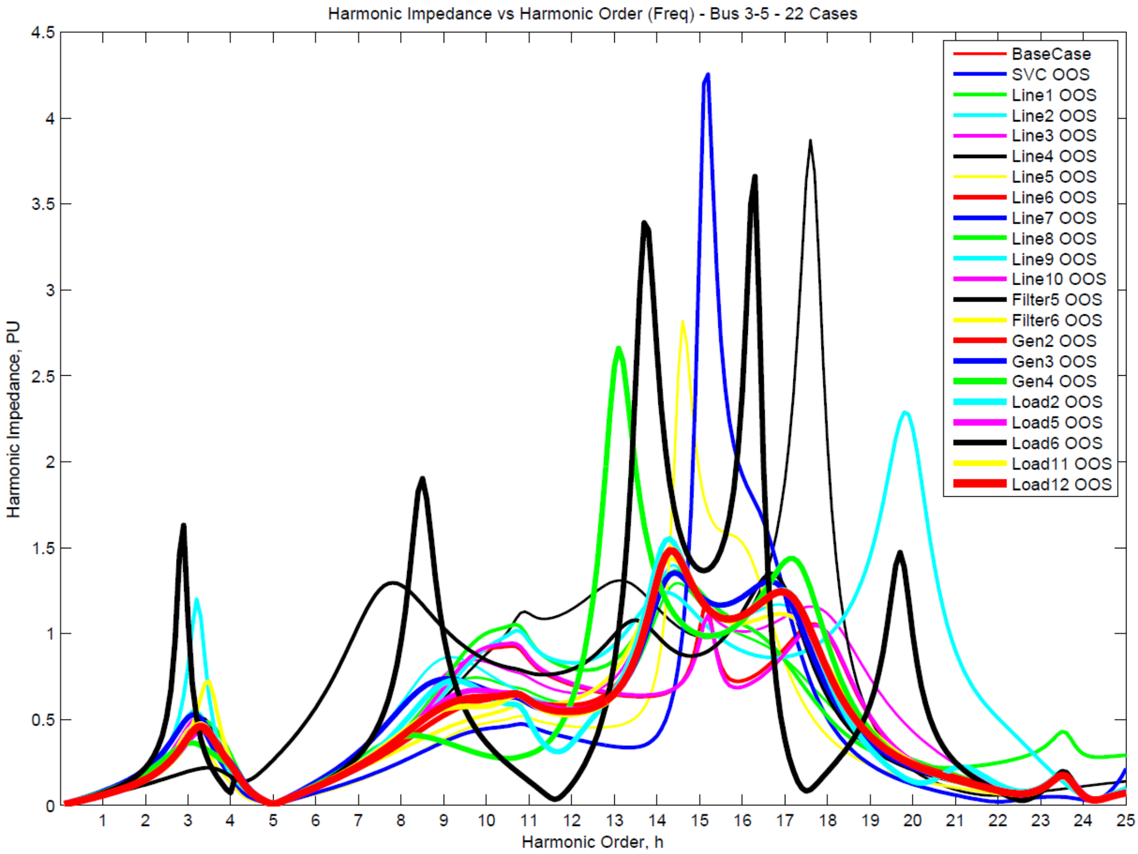
(b). Mutual-Impedance ($Z_{31}(h)$) Between Bus 3 and Bus 1 – 22 Network Scenarios (N-1)



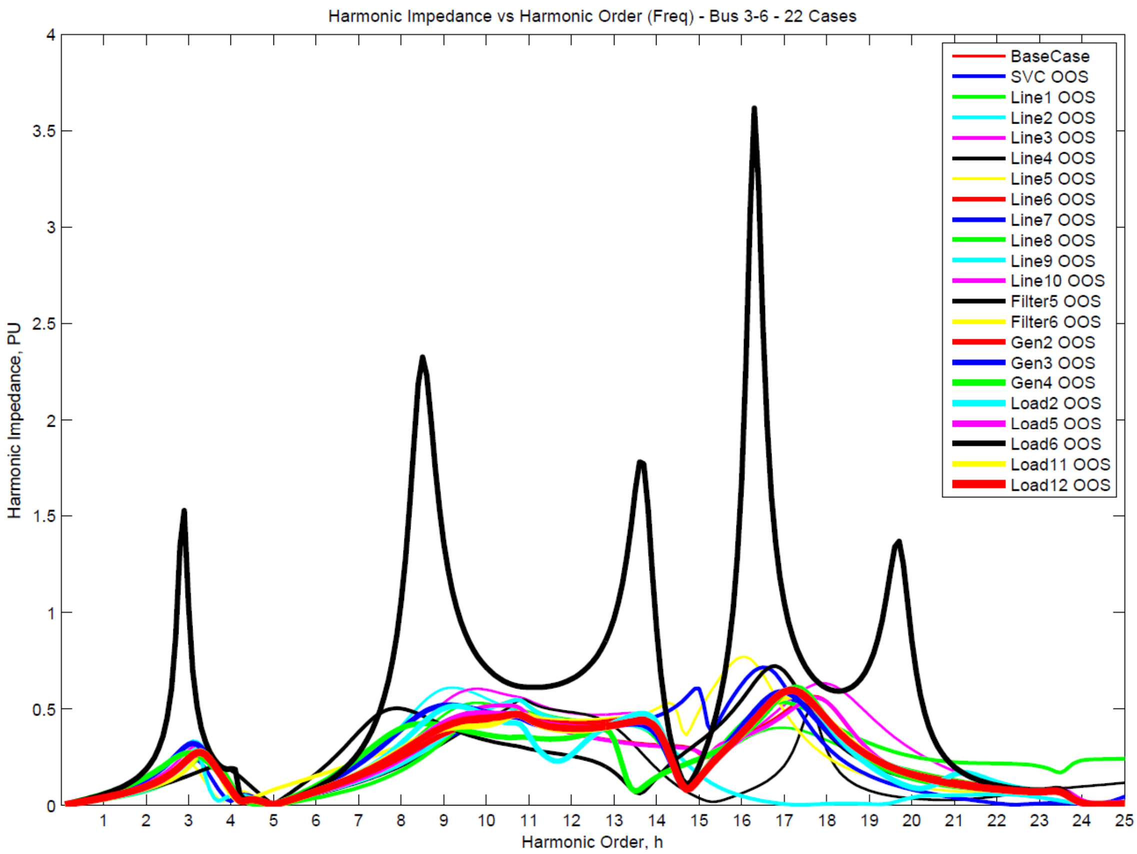
(c). Mutual-Impedance ($Z_{32}(h)$) Between Bus 3 and Bus 2 – 22 Network Scenarios (N-1)



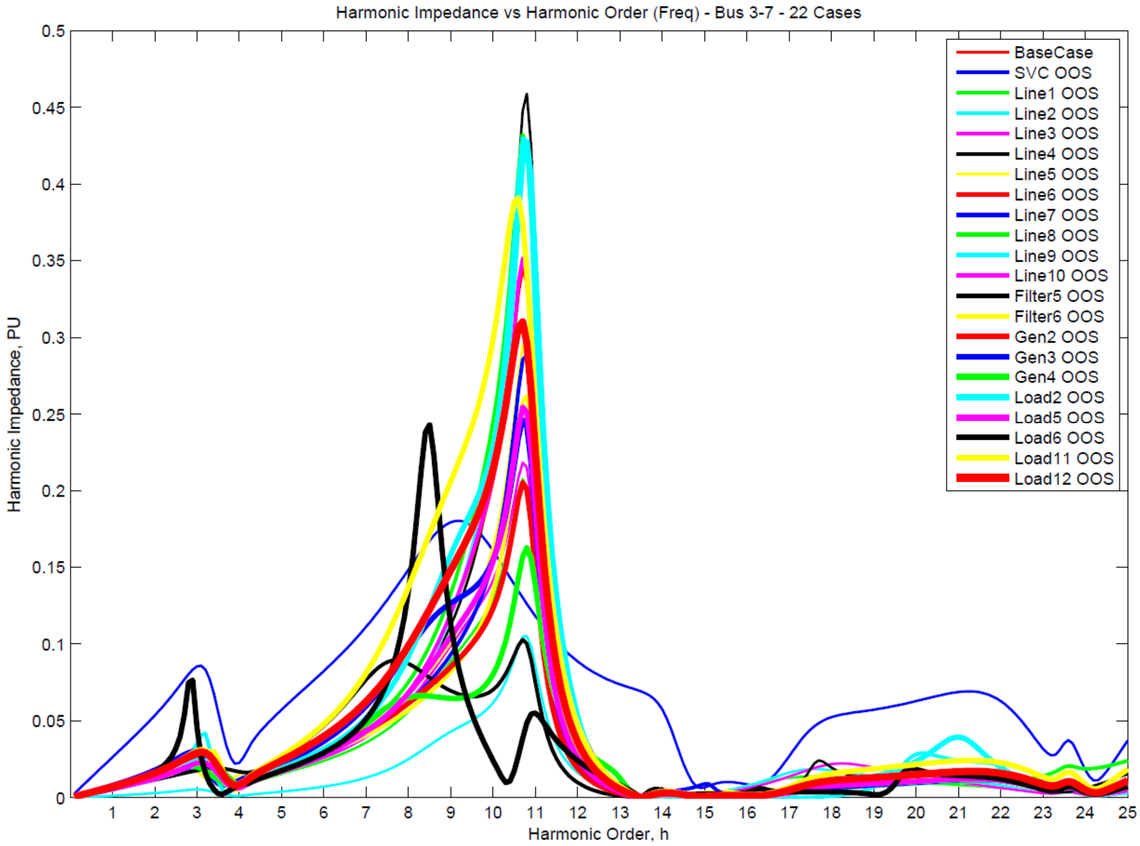
(d). Mutual-Impedance ($Z_{34}(h)$) Between Bus 3 and Bus 4 – 22 Network Scenarios (N-1)



(e). Mutual-Impedance ($Z_{35}(h)$) Between Bus 3 and Bus 5 – 22 Network Scenarios (N-1)



(f). Mutual-Impedance ($Z_{36}(h)$) Between Bus 3 and Bus 6 – 22 Network Scenarios (N-1)



(g). Mutual-Impedance ($Z_{37}(h)$) Between Bus 3 and Bus 7 – 22 Network Scenarios (N-1)

Figure B.16 – Harmonic Impedances ($Z_{ij}(h)$) at Bus 3 - (n-1) Network Contingency Scenarios

Appendix C – Admittances and Impedances of a Case Study Network

Detailed model of Self and Mutual Admittances are calculated as follows:

C.1 Bus 1 Self and Mutual Admittances:

$Y_{1,1}(h) = Y_{Load\_11}(h) + Y_{Load\_12}(h) + [Y_{Hyper\_Line1\_Ser}(h) + Y_{HyperOn2\_Line1\_Shunt}(h)] + [Y_{Hyper\_Line2\_Ser}(h) + Y_{HyperOn2\_Line2\_Shunt}(h)] + (Y_{SVC\_TFMR}(h) / (n_{\_SVCTFMR})^2);$

$Y_{1,2}(h) = - Y_{Hyper\_Line1\_Ser}(h);$

$Y_{1,3}(h) = - Y_{Hyper\_Line2\_Ser}(h);$

$Y_{1,4}(h) = 0;$

$Y_{1,5}(h,) = 0;$

$Y_{1,6}(h) = 0;$

$Y_{1,7}(h) = - (Y_{SVC\_TFMR}(h) / n_{\_SVCTFMR});$ (i.e. Y/n that is the series component only)

C.2 Bus 2 Self and Mutual Admittances:

$Y_{2,1}(h) = - Y_{Hyper\_Line1\_Ser}(h);$

$Y_{2,2}(h) = Y_{Gen2}(h) + Y_{Load2}(h) + [Y_{Hyper\_Line1\_Ser}(h) + Y_{HyperOn2\_Line1\_Shunt}(h)] + [Y_{Hyper\_Line3\_Ser}(h) + Y_{HyperOn2\_Line3\_Shunt}(h)];$

$Y_{2,3}(h) = - Y_{Hyper\_Line3\_Ser}(h);$

$Y_{2,4}(h) = 0;$

$Y_{2,5}(h) = 0;$

$Y_{2,6}(h) = 0;$

$Y_{2,7}(h) = 0;$

C.3 Bus 3 Self and Mutual Admittances:

$Y_{3,1}(h) = - Y_{Hyper\_Line2\_Ser}(h);$

$Y_{3,2}(h) = - Y_{Hyper\_Line3\_Ser}(h);$

$Y_{3,3}(h) = Y_{Gen3}(h) + Y_{Load2}(h) + [Y_{Hyper\_Line2\_Ser}(h) + Y_{HyperOn2\_Line2\_Shunt}(h)] + [Y_{Hyper\_Line3\_Ser}(h) + Y_{HyperOn2\_Line3\_Shunt}(h)] + [Y_{Hyper\_Line4\_Ser}(h) + Y_{HyperOn2\_Line4\_Shunt}(h)] + [Y_{Hyper\_Line5\_Ser}(h) + Y_{HyperOn2\_Line5\_Shunt}(h)] + [Y_{Hyper\_Line7\_Ser}(h) + Y_{HyperOn2\_Line7\_Shunt}(h)] + [Y_{Hyper\_Line8\_Ser}(h) + Y_{HyperOn2\_Line8\_Shunt}(h)];$

$Y_{3,4}(h) = - Y_{Hyper\_Line4\_Ser}(h);$

$Y_{3,5}(h) = - [Y_{Hyper\_Line5\_Ser}(h) + Y_{Hyper\_Line7\_Ser}(h)];$

$Y_{3,6}(h) = - Y_{Hyper\_Line8\_Ser}(h);$

$Y_{3,7}(h) = - Y_{Hyper\_Line3\_Ser}(h);$

C.4 Bus 4 Self and Mutual Admittances:

$Y_{4,1}(h) = - 0;$

$Y_{4,2}(h) = - 0;$

$Y_{4,3}(h) = - Y_{Hyper\_Line4\_Ser}(h);$

$Y_{4,4}(h) = Y_{Gen4}(h) + [Y_{Hyper\_Line4\_Ser}(h) + Y_{HyperOn2\_Line4\_Shunt}(h)] + [Y_{Hyper\_Line6\_Ser}(h) + Y_{HyperOn2\_Line6\_Shunt}(h)];$

$Y_{4,5}(h) = - 0;$

$Y_{4,6}(h) = - [Y_{Hyper\_Line6\_Ser}(h) + Y_{Hyper\_Line10\_Ser}(h)];$

$Y_{4,7}(h) = - 0;$

C.5 Bus 5 Self and Mutual Admittances:

$Y_{5,1}(h) = 0;$

$Y_{5,2}(h) = 0;$

$Y_{5,3}(h) = - [Y_{Hyper\_Line5\_Ser}(h) + Y_{Hyper\_Line7\_Ser}(h)];$

$Y_{5,4}(h) = 0;$

$Y_{5,5}(h) = Y_{Load5}(h) + Y_{Filter5}(h) + Y_{Gen4}(h) + [Y_{Hyper\_Line5\_Ser}(h) + Y_{HyperOn2\_Line5\_Shunt}(h)] + [Y_{Hyper\_Line7\_Ser}(h) + Y_{HyperOn2\_Line7\_Shunt}(h)] + [Y_{Hyper\_Line9\_Ser}(h) + Y_{HyperOn2\_Line9\_Shunt}(h)];$

$Y_{5,6}(h) = - Y_{Hyper\_Line9\_Ser}(h);$

$Y_{5,7}(h) = 0;$

C.6 Bus 6 Self and Mutual Admittances:

$Y_{6,1}(h) = 0;$

$Y_{6,2}(h) = 0;$

$Y_{6,3}(h) = - [Y_{Hyper\_Line5\_Ser}(h) + - Y_{Hyper\_Line7\_Ser}(h)];$

$Y_{6,4}(h) = - [Y_{Hyper\_Line6\_Ser}(h) + Y_{Hyper\_Line10\_Ser}(h)];$

$Y_{6,5}(h) = - Y_{Hyper\_Line9\_Ser}(h);$

$Y_{6,6}(h) = Y_{Load6}(h) + Y_{Filter6}(h) + [Y_{Hyper\_Line6\_Ser}(h) + Y_{HyperOn2\_Line6\_Shunt}(h)] + [Y_{Hyper\_Line8\_Ser}(h) + Y_{HyperOn2\_Line8\_Shunt}(h)] + [Y_{Hyper\_Line9\_Ser}(h) + Y_{HyperOn2\_Line9\_Shunt}(h)];$

$Y_{6,7}(h) = 0;$

C.7 Bus 7 Self and Mutual Admittances:

$Y_{7,1}(h) = -(Y_{SVC\_TFMR}(h) / n\_{SVCTFMR});$

$Y_{7,2}(h) = 0;$

$Y_{7,3}(h) = 0;$

$Y_{7,4}(h) = 0;$

$Y_{7,5}(h) = 0;$

$Y_{7,6}(h) = 0;$

$Y_{7,7}(h) = -[Y_{SVC\_TFMR}(h) + Y_{TCR1}(h) + Y_{TCR1}(h) + Y_{Filter\_5}(h) + Y_{Filter\_7}(h) + Y_{Filter\_11}(h);$

Network harmonic impedance matrix can be derived from the matrix inversion of the admittance matrix:

$$[Z(h)] = \frac{1}{[Y(h)]} \quad \text{(B.39)}$$

Harmonic voltages at all buses in the network can be assessed based on the injection of relevant harmonic current sources and applicable network harmonic impedances as per the equation (B.40) below:

$$\begin{bmatrix} V_1(h) \\ V_2(h) \\ V_3(h) \\ V_4(h) \\ V_5(h) \\ V_6(h) \\ V_7(h) \end{bmatrix} = \begin{bmatrix} Z_{1,1}(h) & Z_{1,2}(h) & Z_{1,3}(h) & Z_{1,4}(h) & Z_{1,5}(h) & Z_{1,6}(h) & Z_{1,7}(h) \\ Z_{2,1}(h) & Z_{2,2}(h) & Z_{2,3}(h) & Z_{2,4}(h) & Z_{2,5}(h) & Z_{2,6}(h) & Z_{2,7}(h) \\ Z_{3,1}(h) & Z_{3,2}(h) & Z_{3,3}(h) & Z_{3,4}(h) & Z_{3,5}(h) & Z_{3,6}(h) & Z_{3,7}(h) \\ Z_{4,1}(h) & Z_{4,2}(h) & Z_{4,3}(h) & Z_{4,4}(h) & Z_{4,5}(h) & Z_{4,6}(h) & Z_{4,7}(h) \\ Z_{5,1}(h) & Z_{5,2}(h) & Z_{5,3}(h) & Z_{5,4}(h) & Z_{5,5}(h) & Z_{5,6}(h) & Z_{5,7}(h) \\ Z_{6,1}(h) & Z_{6,2}(h) & Z_{6,3}(h) & Z_{6,4}(h) & Z_{6,5}(h) & Z_{6,6}(h) & Z_{6,7}(h) \\ Z_{7,1}(h) & Z_{7,2}(h) & Z_{7,3}(h) & Z_{7,4}(h) & Z_{7,5}(h) & Z_{7,6}(h) & Z_{7,7}(h) \end{bmatrix} . \begin{bmatrix} I_1(h) \\ I_2(h) \\ I_3(h) \\ I_4(h) \\ I_5(h) \\ I_6(h) \\ I_7(h) \end{bmatrix} \tag{B.40}$$

Appendix D – MATLAB Code for Harmonic Allocations

Calculations of network harmonic admittances, impedances, harmonic allocations and assessment of voltage compliance at PCCs have been programmed in MATLAB as shown below

```
clear;

close all; % Close All Figures

% Case 1    Allocate to Load 11 and Load 12 Under System Intact Condition    P (MW) Q (MVArs)    kV (PU)    S (MVA)

%*******************************************************************************

    % SVC = OOS

    % St1 (System Intact) - Both Load 11 and Load 12  = OFF          510.77

    % General Load 11 = Max Load 11        232.50    76.40          244.73

    % General Load 12 = Max Load 12        232.50    76.40          244.73

    % St1 - Spare Capacity (Head Room) after both Load 11 and Load 12 are on    21.31

    % Load 2 = OOS        0    0    0    0

    % St2 = Spare Capacity (Load 2 = OFF)          91.33

    % St3  = Spare Capacity for Load          11.64

    % Load 5 = OOS        0    0    0    0

    % St4 (System Intact) - No Load at Bus 4          0.00

    % St5 (System Intact) - Load 5 = OFF          228.42

    % Load 6 = OOS          0    0    0    0

    % St6 (System Intact) - Load 6 = OFF          0.00

    % Filter 5 = OOS        0    0    0    0

    % Gen 1        -480.00 -90.80    2.04    488.51

    % Gen 2        -250.00 -61.80    1.07    257.53

    % Gen 3        -103.90 16.50    0.44    105.26

%*******************************************************************************

k_h = 25*10;     % 25th harmonic order

Harm_File = 'BC1_G8G9_Dev_Harmonic_Allocation_Chapter7.xls';

S_Base = 100*10^6;

U_Base = 132*10^3;
```

```
U1_SVC = 132*10^3;

U2_SVC = 14.1*10^3; % 14.1 kV SVC LV Bus

Z_Base = U_Base^2 / S_Base;

Z_Base_SVC = U2_SVC^2 / S_Base;

Y_Base = 1/Z_Base;

I_Base = S_Base / (sqrt(3)*U_Base);

Z2_Base =  U2_SVC^2 / S_Base; %Z Base for LV side of SVC Transformer, inclusing filters, TSC and TCR

I2_Base = S_Base / (sqrt(3)*U2_SVC);

% Number of lines, buses and loads

N_Lines = 12;       % Number of Lines in the Model

N_Bus = 10;         % Number of Buses in the model - Include SVC LV Bus (Bus 7) connected to Bus 1

N_Loads = 12;       % Maximum number of Loads = 12, but not all loads are present

N_Gens = 12;        % Maximum number of Generators = 12, but not all loads are present

N_Filters = 12;     % Maximum number of Filters = 12, but not all loads are present

U_net =  132*10^3;  % Use for Transformer Model

f=50;               % Fundamental Freq

w = 2*pi*f;

I_TCR = 3080 *1.15;  % TCR Maximum continuous current 3080 = Currents through TCR reactors when it fully conducts - Multiply 1.15 for Overloading Condition

TCR_DelayAngle1 = (115/180)*pi;                         % Delay Firing Angle of Positive half cycle

TCR_DelayAngle2 = (115.8/180)*pi;                       % Delay Firing Angle of Negative half cycle, Make it different to generate even harmonic contents (realistic condition)

TCR_DelayAngle = (TCR_DelayAngle1 + TCR_DelayAngle2) / 2;   % Delay Firing Angle = Average of Positive and Negative Delay firing Angle

TCR_DiffAngle = (TCR_DelayAngle1 - TCR_DelayAngle2) / 2;    % Mean Difference between delay of positive and negative delay firing angles

% In reallity there is a small difference between delay of positive and

% negative half cycles.  Therefore non-characteristic harmonics exist

%Initialise Matrices

Yh(1:k_h, 1:N_Bus,1:N_Bus) = 0;

Zh(1:k_h, 1:N_Bus,1:N_Bus) = 0; % changed to make Zh 3-dimensional array
```

```
EIhi(1:k_h, 1:N_Bus) = 0;

EUhi(1:k_h, 1:N_Bus) = 0;

Vh(1:k_h, 1:N_Bus) = 0;

Vh_NoAlpha(1:k_h, 1:N_Bus) = 0;

Vha(1:k_h, 1:N_Bus) = 0;

Gh(1:k_h, 1:N_Bus) = 0;          % For Each harmonic, reset Gh

Gh_Test(1:k_h, 1:N_Bus) = 0;          % For Each harmonic, reset Gh

IEC_Limit(1:k_h,1)  =0;

% ***********************************************************************

Rdc_Line(1:k_h,1:N_Lines)= 0;

PF_Load(1:k_h,1:N_Loads) = 0;

R_Load(1:k_h,1:N_Loads) = 0;

TanPhi_Load(1:k_h,1:N_Loads) = 0;

x_Line(1:k_h,1:N_Lines) = 0;

Rh_Line(1:k_h,1:N_Lines) = 0;

Zh_Line_Ser(1:k_h,1:N_Lines) = 0;

Yh_Line_Shunt(1:k_h,1:N_Lines) = 0;

Zh_Hyper_Line_Ser(1:k_h,1:N_Lines) = 0;

Yh_Hyper_Line_Ser(1:k_h,1:N_Lines) = 0;

Yh_HyperOn2_Line_Shunt(1:k_h,1:N_Lines) = 0;

Xs_Load(1:k_h,1:N_Loads) = 0;

Xp_Load(1:k_h,1:N_Loads) = 0;

Zh_Load(1:k_h,1:N_Loads)= 0;

Yh_Load(1:k_h,1:N_Loads) = 0;

R1_Gen(1:k_h,1:N_Gens) = 0;

Xh_Gen(1:k_h,1:N_Gens)= 0;

Rh_Gen(1:k_h,1:N_Gens) = 0;

Zh_Gen(1:k_h,1:N_Gens) = 0;

Yh_Gen(1:k_h,1:N_Gens) = 0;

Z_Filter(1:k_h,1:N_Filters) = 0;
```

```
Y_Filter(1:k_h,1:N_Filters) = 0;
% SVC
Xh_SVC_TFMR(1:k_h) = 0;
Rsh_SVC_TFMR(1:k_h) = 0;
Rph_SVC_TFMR(1:k_h) = 0;
Zh_SVC_TFMR(1:k_h) = 0;
Yh_SVC_TFMR(1:k_h) = 0;
Zh_TCR(1:k_h) = 0;
Yh_TCR(1:k_h)  = 0;
Zh_TSC(1:k_h)  = 0;
Yh_TSC(1:k_h)  = 0;
Zh_5HF(1:k_h) = 0;
Zh_7HF(1:k_h) = 0;
Zh_11HF(1:k_h) = 0;
Yh_5HF(1:k_h) = 0;
Yh_7HF(1:k_h) = 0;
Yh_11HF(1:k_h) = 0;
Yh_SVC(1:k_h) = 0;
Si(1:N_Bus) = 0;
St(1:N_Bus) = 0;
K(1:k_h,1:N_Bus,1:N_Bus) = 0;
Zh_Temp(1:N_Bus,1:N_Bus) = 0;
K_Angle(1:k_h,1:N_Bus,1:N_Bus) = 0;
EUhi_Load_11(1:k_h) = 0;
EIhi_Load_11(1:k_h) = 0;
EUhi_Load_12(1:k_h) = 0;
EIhi_Load_12(1:k_h) = 0;
EIhi(1:k_h,1:N_Bus) = 0;
EUhi(1:k_h,1:N_Bus) = 0;
d = 10^(-25);
```

```
dmax = 10^(25);

dmin = 10^(-9);

EUhi_SpareCapacity(1:k_h,1:N_Bus) = 0;

Bus1_PastHarmData(1:k_h*3)= 0;

Bus2_PastHarmData(1:k_h*3)= 0;

Bus3_PastHarmData(1:k_h*3)= 0;

Bus4_PastHarmData(1:k_h*3)= 0;

Bus5_PastHarmData(1:k_h*3)= 0;

Bus6_PastHarmData(1:k_h*3)= 0;

Bus7_PastHarmData(1:k_h*3)= 0;

Bus8_PastHarmData(1:k_h*3)= 0;

Bus9_PastHarmData(1:k_h*3)= 0;

Bus1_PastHarmData = xlsread(Harm_File, 1, 'C5:C79');

Bus2_PastHarmData = xlsread(Harm_File, 1, 'E5:E79');

Bus3_PastHarmData = xlsread(Harm_File, 1, 'G5:G79');

Bus4_PastHarmData = xlsread(Harm_File, 1, 'I5:I79');

Bus5_PastHarmData = xlsread(Harm_File, 1, 'K5:K79');

Bus6_PastHarmData = xlsread(Harm_File, 1, 'M5:M79');

Bus7_PastHarmData = xlsread(Harm_File, 1, 'O5:O79');

Bus8_PastHarmData = xlsread(Harm_File, 1, 'Q5:Q79');

Bus9_PastHarmData = xlsread(Harm_File, 1, 'S5:S79');

Existing_Currents = 1;

% SVC Stat

SVCStat = 0;                                    % This parameter is used to turn SVC transformer
Impedance On / OFF

% *********************Line data  - 12 lines Array ***********************

% R     (Ohm)   7.183476           4.441896   5.922528  5.922528  4.441896  11.414680 11.414680
5.922528  1E+25 5.922528 1E+25 1E+25

% X     (Ohm)   55.74420  33.42465  44.56620 44.56620 33.42465 46.78752 46.78752  44.56620 1E+25
44.56620  1E+25 1E+25

% L     (km)    180        90        120       120       90        120       120       120       1E-25     120
1E-25 1E-25
```

```
% C       (uF/km) 0.01181993          0.0100062           0.010.0100062     0.0100062 0.00950088
            0.00950088          0.0100062           0.0100062           0.01000620 1E-25 1E-25

% Status    1        1            1            1            1            1            1            0            0            0  0  0

R1_Line =          [7.18347600  4.44189600  5.92252800  5.92252800  4.44189600  11.41468000
11.41468000  5.92252800  5.92252800  5.92252800 4.44189600 4.44189600];           % Ohms

X1_Line = [55.74420000  33.42465000  44.56620000            44.56620000  33.42465000  46.78752000
46.78752000        44.56620000        44.56620000  44.56620000  33.42465000 33.42465000];    % Ohms

L_Line = [180 90 120 120 90          120         120         120         110 120 45 45];       % length in km

C_Line = 10^-6*[0.01181993*180 0.0100062*90      0.0100062*120 0.0100062*120       0.0100062*90
0.00950088*120  0.00950088*120 0.0100062*120 0.0100062*110 0.01000620*120 0.0100062*45
0.0100062*45];      % F (= uF/km * L)

Line_St = [256.949 253.82 138.7 31.85 161.02 72.47 70.45 300 300 300 300 300];

LineStat = [1 1 1 1 1 1 1 0 1 0 1 1];   % Lines 1-7, 9,11,12 are In,  Line2 8, 10 OOS

%L_Line = [180 90 120 120 90       120         120         120         10^-9 120 10^-9 10^-9];       % length in
km

%C_Line = 10^-6*[0.01181993*180 0.0100062*90   0.0100062*120 0.0100062*120       0.0100062*90
0.00950088*120  0.00950088*120 0.0100062*120 0.0100062*10^-9 0.01000620*120 0.0100062*10^-9
0.0100062*10^-9];      % F (= uF/km * L)

%Line_St = [256.949 253.82 138.7 31.85 161.02 72.47 70.45 300 300 300 300 300];

% *********************Shunt Filter Data  - ONe Filter is Active - Model 12 Filter Array

%Bus     Name       Volts     C          L          R       Current        Steps       Q

%Bus 5  Shunt 5     132       5.138009           123.2496            3.0976    131.2141258    1         29.9995783

%Bus 6  Shunt 6     132       5.138009           123.2496            3.0976    131.2141258    1         29.9995783

% Cap 5 and Cap 6 were tuned as 4th Harmonic Filters in Chapter 3 of

% thesis, Quality Factor Q = 12.5

%R_Filter = [d d d d 3.0976   3.0976   d d d d d d]; % Resistance (Ohm)

%L_Filter = [d d d d 123.2496 123.2496 d d d d d d d]*10^-3; % Inductance (H)

%C_Filter = [d d d d 5.138009 5.138009 d d d d d d]*10^-6; % Capacitance (F)

% Cap 5 and Cap 6 are now tuned as 5th Harmonic Filters in Chapter 4 of

% Thesis

R_Filter = [d d d d 3.0976   3.0976   d d d d d d]; % Resistance (Ohm) Quality Factor Q = 8
```

```
L_Filter = [d d d d 78.8797 78.8797 d d d d d d d]*10^-3; % Inductance (H)

C_Filter = [d d d d 5.138009 5.138009 d d d d d d]*10^-6; % Capacitance (F)

FilterStat = [0 0 0 0 0 0 0 0 0 0 0 0 0]; %  Filter 5 and 6 are OOS

% *********************SVC Data (Woree SVC -80 / +150 MVArs ***********************

S_SVC = 150*10^6;              % 150MVArs

S_SVC_TFMR = 150*10^6;         % SVC Transformer

Q_TCR = 115*10^6 / S_Base;     % Q_TCR = 115 MVArs

L_TCR = 15.85 * 10^-3 / 3 ;  % Thyristor Controlled Reactor 15.85 mH, but need to divide by 3 due to
Delta connection

L_TSC = 0.94 * 10^-3 / 3;   % TSC Inrush Reactor = 0.94 mH - Divide by 3 due to Delta COnnection

C_TSC = 532.3 *10^-6 / 3;   % TSC Capacitor = 532.3 uF - Divide by 3 due to Delta connection

L_5HF = 1.95 * 10^-3;      % 5HF Tuning Reactor = 1.95 mH

C_5HF = 209.9 * 10^-6;     % 5HF Capacitor = 209.9 uF

R_5HF = 61;                % 5HF Damping Resistor = 61 Ohm

L_7HF = 1.46 * 10^-3;      % 7HF Tuning Reactor = 1.46 mH

C_7HF = 142.8 * 10^-6;     % 7HF Capacitor = 142.8 uF

R_7HF = 64;                % 7HF Damping Resistor = 64 Ohm

L_11HF = 0.58 * 10^-3;     % 11HF Tuning Reactor = 0.58 mH

C_11HF = 144.6 * 10^-6;    % 11HF Capacitor = 144.6 uF

R_11HF = 20;               % 11HF Damping Resistor = 20 Ohm

% *********************SVC Transformer - Between Bus 1 and Bus 7 (SVC LV Bus)

% SVC Tfmr X = 11% +/- 0.55% -> Xmax = 0.115 on SVC Transformer 150 MVA

X_SVC_TFMR =(0.11 + 0.0055) *(S_Base/ S_SVC_TFMR);  % X tfmr = 11% +/- 0.55% @150MVA -
convert to pu in 100MVA Base

Tan_Phi_SVC_TFMR = exp(0.693+0.796*log(S_SVC_TFMR / 10^6)-0.0421*(log(S_SVC_TFMR /
10^6))^2);  % Tan(phi1)= exp(0.693 + 0.796*ln(Sn) - 0.0421*(ln(Sn))^2)

% Transformer Tap - Currently set as fixed tap - n = 1

U1_SVCTFMR_Rated = 1.1*U1_SVC;

U2_SVCTFMR_Rated  = 1.1*U2_SVC;

U1_Nom_Network = 1.07 * U1_SVC;                                  % SVC Tfmr #1 from Bus
1 to Bus 7 Nominal Network Voltage
```

U2_Nom_Network = 1.07 * U2_SVC;

% Transformer Tap Ratio = 1 in this case

n_SVCTFMR = (U1_SVCTFMR_Rated / U2_SVCTFMR_Rated)* (U2_Nom_Network / U1_Nom_Network);

% *********************Generator data - 3 Active Generators - Model 12 Generator Array

% Generators at Bus 2,3 and 4 -

% Model all generators as conventional generators - therefore use CIGRE Model

% Gen 1 at Bus

% Case 1 (MW / MVAR / MVA

% G2 = 480 / 90.8 / 488.51

% G3 = 250 / 61.8 / 257.53

% G4 = 103.9 / -16.5 / 105.2

% G8 (SF1) = 311.09 / 75 / 320

% G9 (SF2) = 515.77 / 98 / 525

% G10 (SF3) = 120 / 35 / 125

% Load 11 = 232.5 / 76.4 / 244.73

% Load 12 = 232.5 / 76.4 / 244.73

% Load 2 = 90 / 29.5 / 94.71

% Load 5 = 220 / 72.3 / 231.58

% Load 6 OOS = 0

Xd_Gen = [d 0.14699 0.235 0.15 d d d 1.15 1.15 1.15 d d]; % PU Store Data in 12 element array

MW_Gen = [d 480 250 103.9 d d d 311.09 515.77 120 d d] *(10^6 / S_Base); % Store Generator MW Data in 12 element array

MVAr_Gen = [d 90.8 61.8 -16.5 d d d 75 98 35 d d] *(10^6 / S_Base); % Store Generator MVArs Data in 12 element array

MVA_Gen = [d 488.51 257.53 105.26 d d d 320 525 125 d d] *(10^6 / S_Base); % Store Generator MVA Data in 12 element array

GenStat = [0 1 1 1 0 0 0 1 1 1 0 0]; % Gens 2,3,4, Gen 8 (SF1) are in service, Gen 9 (SF2), Gen 10 (SF3)Others are OOS

% ********************Load data - 12 loads Array ***********************

% Model 12 Loads - Active Loads are Load 2, 5, 6, 11 and 12

%Name Active Power Reactive Power Apparent Power

% MW Mvar MVA Power Factor Scaling Factor

% Bus 1 Load 11 232.5 76.4 244.73 0.9499999 1

% Load 12 232.5 76.4 244.73 0.9499999 1

% Bus 2 Load 2 86.85 28.56 91.43 0.9499999 1

% Bus 5 Load 5 217.30 71.32 228.45 0.95 1

% Bus 6 Load 6 220.00 72.30 231.58 1

LF11 = 1.0; % Load 11 can be set at Max = 2.4025 x Nominal load

LF12 = 1.0; % Load 12 can be set at Max = 2.4025 x Nominal load

LF2 = 1.0; % Load 2 can be set at 1.0 (Nominal Load)

LF5 = 1.0; % Load 5 can be set at 1.0 time (Nomial Load)

LF6 = 1.0; % Load 6 can be Out of Service - Load 6 is set at 1.0 time (Nomial Load)

LF8 = 0.05; % Reduce load size of GEn 8 (SF1)

LF9 = 0.05; % Reduce load size of GEn 8 (SF1)

LF10 = 0.05; % Reduce load size of GEn 8 (SF1)

%It's not requied to allocate for load 7, .i.e SVC (exsiting), hence Si(7)= 0

P_Load = [d (86.85 * LF2) d d (217.30 * LF5) (220.00 * LF6) d d d d (232.5 * LF11) (131 * LF12)]*(10^6 / S_Base); % pu Active Power - Load 11 and 12

Q_Load = [d (28.56 * LF2) d d (71.32 * LF5) (72.30 * LF6) d d d d (76.4 * LF11) (75.1 * LF12)] *(10^6 / S_Base); % pu Reactive Power

S_Load = [d (91.43 * LF2) d d (228.70 * LF5) (231.58 * LF6) d d d d (244.73 * LF11) (151.04 * LF12)] *(10^6 / S_Base); % pu Reactive Power

LoadStat = [0 1 0 0 1 1 0 1 1 1 1 1]; % only Load 2, 5, 8 (Solar Farm), 11 and 12 are in service , Other Loads are not in service or donot exist

% Model Solarfarms as Harmonic Current Sources that also required to be

% allocated

% Load 8 (I Source) Load 9 Load 10

%MVA 313.60 514.50 122.50

%P 3.136 5.145 1.225

%Q 1.725 2.830 0.674

% 6.400 10.500 2.500 Spare Supply Capacity at Bus 8, 9 and 10

```
% ***************************** Total Supply Capacity of each bus and individual loads to be installed in the network

% St is the Total / Maximum Supply Capacity of each Bus at fundamental frequency before network augmentation is required

% St is required only for buses that have proposed loads to be installed.

% For buses that do not have load installed St = 0

B1_Max = 1.0;

B2_Max = 1.0;

B3_Max = 1.0;

B4_Max = 1.0;

B5_Max = 1.0;

B6_Max = 1.0;

B7_Max = 1.0;

B8_Max = 1.0;

B9_Max = 1.0;

B10_Max = 1.0;

B11_Max = 1.0;

B12_Max = 1.0;

% St_Spare must be less than St - St and St_Spare must be in PU

St1_Spare = 20.24 *(10^6 / S_Base);

St1_Margin = 1.07 *(10^6 / S_Base);

St1 = B1_Max * (S_Load(11) + S_Load(12)+ St1_Spare + St1_Margin);

St2_Spare = 4.25*(10^6 / S_Base);        % PU

St2_Margin = 0.22 *(10^6 / S_Base);

St2 = B2_Max * (S_Load(2) + St2_Spare + St2_Margin);

St3_Spare = 5.82*(10^6 / S_Base);

St3_Margin = 5.82 *(10^6 / S_Base);

St3 = B3_Max * (S_Load(3) + St3_Spare + St3_Margin);

St4_Spare = dmin*(10^6 / S_Base);

St4_Margin = dmin*(10^6 / S_Base);

St4 = B4_Max * (S_Load(4) + St4_Spare + St4_Margin);
```

```
St5_Spare = 10.85*(10^6 / S_Base);  %

St5_Margin = 0.57 *(10^6 / S_Base);

St5 = B5_Max * (S_Load(5) + St5_Spare + St5_Margin);

St6_Spare = dmin*(10^6 / S_Base);

St6_Margin = dmin*(10^6 / S_Base);

St6 = B6_Max * (S_Load(6) + St6_Spare + St6_Margin);

St7_Spare = dmin*(10^6 / S_Base);

St7_Margin = dmin*(10^6 / S_Base);

St7 = B7_Max * (S_Load(7) + St7_Spare + St7_Margin);

St8_Spare = 6.0*(10^6 / S_Base);

St8_Margin = 0.4*(10^6 / S_Base);

St8 = B8_Max * ((S_Load(8)/LF8) + St8_Spare + St8_Margin);

St9_Spare = 10.0*(10^6 / S_Base);

St9_Margin = 0.5 *(10^6 / S_Base);

St9 = B9_Max * (S_Load(9) + St9_Spare + St9_Margin);

St10_Spare = 2.0*(10^6 / S_Base);

St10_Margin = 0.5*(10^6 / S_Base);

St10 = B10_Max * (S_Load(10) + St10_Spare + St10_Margin);

St11_Spare = dmin*(10^6 / S_Base);

St11_Margin = dmin*(10^6 / S_Base);

St11 = B11_Max * (d + St11_Spare + St11_Margin);

St12_Spare = dmin*(10^6 / S_Base);

St12_Margin = dmin*(10^6 / S_Base);

St12 = B12_Max * (d + St12_Spare + St12_Margin);

% St_Spare in PU

St_Spare = [St1_Spare St2_Spare St3_Spare St4_Spare  St5_Spare St6_Spare St7_Spare St8_Spare
St9_Spare  St10_Spare St11_Spare St12_Spare];

% St in PU

St =[St1 St2 St3 St4 St5 St6 St7 St8 St9 St10 St11 St12];  % MVA Total Load at each Bus Sti (Load 6
OOS)

  %      St1          St2    St3 St4 St(5)     St(6)    St(7)
```

```
%       St7 - 115 MVArs = TCR Power

%       St(6)(OOS)

% Individual Load installed in the network in pu

Si =[(S_Load(1)*LoadStat(1)) (S_Load(2)*LoadStat(2)) (S_Load(3)*LoadStat(3))
(S_Load(4)*LoadStat(4)) (S_Load(5)*LoadStat(5)) (S_Load(6)*LoadStat(6)) (S_Load(7)*LoadStat(7))
(S_Load(8)*LoadStat(8)) (S_Load(9)*LoadStat(9)) (S_Load(10)*LoadStat(10))
(S_Load(11)*LoadStat(11)) (S_Load(12)*LoadStat(12)) ] ;  % MVA Total Load at each Bus Sti (Load 6
OOS)

for h = 1: k_h  % Equivalent to For h = 1 to 25 step 0.1

%Line 1 to Line 10 (Only 10 lines exist at this stage

  for g = 1:12

    if (LineStat(g) == 1)

      Rdc_Line(h,g)= (R1_Line(g) - 0.004398*L_Line(g))/0.938;  % Ohm

      x_Line(h,g) = 0.3545*(sqrt((h/10)/(Rdc_Line(h,g)/L_Line(g))));

      if (x_Line(h,g)> 2.4)

        Rh_Line(h,g) = Rdc_Line(h,g)*(0.35*x_Line(h,g) + 0.3);

      else

        Rh_Line(h,g) = Rdc_Line(h,g)*(0.035*(x_Line(h,g))^2 + 0.938);

      end

      Zh_Line_Ser(h,g) =  (Rh_Line(h,g) +1i*(h/10)*X1_Line(g))/Z_Base;        % Conversion to PU

      Yh_Line_Shunt(h,g) = (1i*(h/10)*w*C_Line(g)) / Y_Base;               % Conversion to PU

      Zh_Hyper_Line_Ser(h,g) =  (Zh_Line_Ser(h,g) *
sinh(sqrt(Zh_Line_Ser(h,g)*Yh_Line_Shunt(h,g)))) / sqrt(Zh_Line_Ser(h,g)*Yh_Line_Shunt(h,g));

      Yh_Hyper_Line_Ser(h,g) = 1/Zh_Hyper_Line_Ser(h,g);

      % Y'/2

      Yh_HyperOn2_Line_Shunt(h,g) =  (Yh_Line_Shunt(h,g) *
tanh(sqrt(Zh_Line_Ser(h,g)*Yh_Line_Shunt(h,g)) / 2)) / sqrt(Zh_Line_Ser(h,g)*Yh_Line_Shunt(h,g));

      % In Service Elements - For future works only

      Yh_Hyper_Line_Ser(h,g) = Yh_Hyper_Line_Ser(h,g)* LineStat(g);

      Yh_HyperOn2_Line_Shunt(h,g)  = Yh_HyperOn2_Line_Shunt(h,g) * LineStat(g);

    end

    if (LoadStat(g) == 1)

      PF_Load(h,g) = P_Load(g) / S_Load(g);
```

```
R_Load(h,g) = (U_net / U_Base)^2 / P_Load (g);  % R_Load in pu , P_Load is in pu therefore
Unet must also be converted to pu

TanPhi_Load(h,g) = Q_Load(g) / P_Load(g);

Xs_Load(h,g) = 0.073*((h/10))*R_Load(h,g);                    % Already in PU

Xp_Load(h,g) =(h/10)*R_Load(h,g) / (6.7*TanPhi_Load(h,g)-0.74);        % Already in PU

Zh_Load(h,g)=
((R_Load(h,g)+1i*Xs_Load(h,g))*1i*Xp_Load(h,g))/(R_Load(h,g)+1i*Xs_Load(h,g)
+1i*Xp_Load(h,g));

Yh_Load(h,g) = 1/Zh_Load(h,g);

% Inservice Elements only

Yh_Load(h,g) = Yh_Load(h,g)*LoadStat(g);                 % Inservice Elements only

end

if (GenStat(g) == 1)

R1_Gen(h,g) = 0.1*(Xd_Gen(g)/MVA_Gen(g));                   % Already in pu, but need to
scale to 100 MVA Base, instead of Generator MVA

Xh_Gen(h,g)= (h/10)*(Xd_Gen(g)/MVA_Gen(g));                  % Akready in pu

Rh_Gen(h,g) = sqrt((h/10))*R1_Gen(h,g);                  % R1_Gen is in pu already

Zh_Gen(h,g) = Rh_Gen(h,g)+ 1i*Xh_Gen(h,g);

Yh_Gen(h,g) = 1/Zh_Gen(h,g);

% Inservice Elements only

Yh_Gen(h,g) = Yh_Gen(h,g)*GenStat(g);     % Inservice Elements only

end

if (FilterStat(g) == 1)

Z_Filter(h,g) = (R_Filter(g) +1i*(h/10)*w*L_Filter(g) + 1/(1i*(h/10)*w*C_Filter(g))) / Z_Base;

Y_Filter(h,g) = 1 / Z_Filter(h,g);

% Inservice Elements only

Y_Filter(h,g) =Y_Filter(h,g) * FilterStat(g);    % Inservice Elements only

end

end

% SVC Transformer between bus 1 and bus 7

%    if (SVCStat == 1)

Xh_SVC_TFMR(h) = (h/10) * X_SVC_TFMR;                 % In pu
```

```
Rsh_SVC_TFMR(h) = X_SVC_TFMR / Tan_Phi_SVC_TFMR;           % In pu

Rph_SVC_TFMR(h) = 10 * X_SVC_TFMR * Tan_Phi_SVC_TFMR;      % In pu

Zh_SVC_TFMR(h) = Rsh_SVC_TFMR(h) + ((Rph_SVC_TFMR(h) * (1i*Xh_SVC_TFMR(h))) / (Rph_SVC_TFMR(h) + (1i*Xh_SVC_TFMR(h))));

Yh_SVC_TFMR(h) = (1 / Zh_SVC_TFMR(h));

% SVC Status

%       Yh_SVC_TFMR(h) = Yh_SVC_TFMR(h) * SVCStat + d;  % - Remove because

%       even if SVC is not installed, the transformer will still need to

%       be there for bus 7 to be valid

% TCR

Zh_TCR(h)  = (1i*(h/10)*w*L_TCR) / Z_Base_SVC;

Yh_TCR(h)  = 1 / Zh_TCR(h);

% SVC Status

Yh_TCR(h) = Yh_TCR(h) * SVCStat + d;  % SVC Status

% TSC

Zh_TSC(h)  = ((1i*(h/10)*w*L_TSC) + 1 /(1i*(h/10)*w*C_TSC))/ Z_Base_SVC;

Yh_TSC(h)  = 1 / Zh_TSC(h);

% SVC Status

Yh_TSC(h)  =Yh_TSC(h)  * SVCStat + d; % SVC Status

% Filter Impedance and Admittance

Zh_5HF(h) = ((1 / 1i*w*(h/10)*C_5HF) + ((R_5HF * (1i*w*(h/10)*L_5HF)) / (R_5HF + (1i*w*(h/10)*L_5HF)))) / Z_Base_SVC;  % pu Damping Resistor is in parallel with tuning reactor

Zh_7HF(h) = ((1 / 1i*w*(h/10)*C_7HF) + ((R_7HF * (1i*w*(h/10)*L_7HF)) / (R_7HF + (1i*w*(h/10)*L_7HF)))) / Z_Base_SVC;  % pu Damping Resistor is in parallel with tuning reactor

Zh_11HF(h) = ((1 / 1i*w*(h/10)*C_11HF) + ((R_11HF * (1i*w*(h/10)*L_11HF)) / (R_11HF + (1i*w*(h/10)*L_11HF)))) / Z_Base_SVC;  % pu Damping Resistor is in parallel with tuning reactor

Yh_5HF(h) = 1 / Zh_5HF(h) + d;

Yh_7HF(h) = 1 / Zh_7HF(h) + d;

Yh_11HF(h) = 1 / Zh_11HF(h) + d;

% SVC Status

Yh_5HF(h) = Yh_5HF(h) * SVCStat + d;

Yh_7HF(h) = Yh_7HF(h) * SVCStat + d;
```

```
    Yh_11HF(h) = Yh_11HF(h) * SVCStat + d;

    Yh_SVC(h) = Yh_TCR(h) + Yh_TSC(h) + Yh_5HF(h) + Yh_7HF(h) + Yh_11HF(h);

 %   end

% Calc Bus Admittance Matrix Using CIGRE Model

  Yh(h,1,1) = Yh_Load(h,11) + Yh_Load(h,12)+ (Yh_Hyper_Line_Ser(h,1)
+Yh_HyperOn2_Line_Shunt(h,1)) + (Yh_Hyper_Line_Ser(h,2) +Yh_HyperOn2_Line_Shunt(h,2)) +
(Yh_SVC_TFMR(h) / n_SVCTFMR^2); % With SVC TFMR = Y/n + (Y/n^2 - Y/n) = Y/n^2

  Yh(h,1,2) = -Yh_Hyper_Line_Ser(h,1);

  Yh(h,1,3) = -Yh_Hyper_Line_Ser(h,2);

  Yh(h,1,4) = 0;

  Yh(h,1,5) = 0;

  Yh(h,1,6) = 0;

  Yh(h,1,7) = -(Yh_SVC_TFMR(h) / n_SVCTFMR);   % ie.  Y/n that is the series component only

  Yh(h,1,8) = 0;

  Yh(h,1,9) = 0;

  Yh(h,1,10) = 0;

  Yh(h,2,1) = -Yh_Hyper_Line_Ser(h,1);

  Yh(h,2,2) = Yh_Gen(h,2)+ Yh_Load(h,2) + (Yh_Hyper_Line_Ser(h,1)
+Yh_HyperOn2_Line_Shunt(h,1)) + (Yh_Hyper_Line_Ser(h,3) +Yh_HyperOn2_Line_Shunt(h,3)); %
Generator #2 is currently modelled as conventional Turbine - To be modified to PV Gen

  Yh(h,2,3) = -Yh_Hyper_Line_Ser(h,3);

  Yh(h,2,4) = 0;

  Yh(h,2,5) = 0;

  Yh(h,2,6) = 0;

  Yh(h,2,7) = 0;

  Yh(h,2,8) = 0;

  Yh(h,2,9) = 0;

  Yh(h,2,10) = 0;

  Yh(h,3,1) = -Yh_Hyper_Line_Ser(h,2);

  Yh(h,3,2) = -Yh_Hyper_Line_Ser(h,3);

  % Gen 3 is a Conventional Generator, Line 8 is out of service
```

Yh(h,3,3) = Yh_Gen(h,3) + (Yh_Hyper_Line_Ser(h,2) +Yh_HyperOn2_Line_Shunt(h,2)) + (Yh_Hyper_Line_Ser(h,3) +Yh_HyperOn2_Line_Shunt(h,3))+ (Yh_Hyper_Line_Ser(h,4) +Yh_HyperOn2_Line_Shunt(h,4))+(Yh_Hyper_Line_Ser(h,5) + Yh_HyperOn2_Line_Shunt(h,5)) + (Yh_Hyper_Line_Ser(h,7) +Yh_HyperOn2_Line_Shunt(h,7)) + (Yh_Hyper_Line_Ser(h,8) + Yh_HyperOn2_Line_Shunt(h,8)) + (Yh_Hyper_Line_Ser(h,11) +Yh_HyperOn2_Line_Shunt(h,11)); % Generator #3 is modelled as conventional Turbine

Yh(h,3,4) = -Yh_Hyper_Line_Ser(h,4);

Yh(h,3,5) = -Yh_Hyper_Line_Ser(h,5) - Yh_Hyper_Line_Ser(h,7);

Yh(h,3,6) = -Yh_Hyper_Line_Ser(h,8);

Yh(h,3,7) = 0;

Yh(h,3,8) = 0;

Yh(h,3,9) = -Yh_Hyper_Line_Ser(h,11);

Yh(h,3,10) = 0;

Yh(h,4,1) = 0;

Yh(h,4,2) = 0;

Yh(h,4,3) = -Yh_Hyper_Line_Ser(h,4);

% Gen 4 is a Conventional Generator, Line 10 is out of service

Yh(h,4,4) = Yh_Gen(h,4) + (Yh_Hyper_Line_Ser(h,4) +Yh_HyperOn2_Line_Shunt(h,4)) + (Yh_Hyper_Line_Ser(h,6) +Yh_HyperOn2_Line_Shunt(h,6)) + (Yh_Hyper_Line_Ser(h,10) +Yh_HyperOn2_Line_Shunt(h,10)); % Generator #4 is modelled as conventional Turbine, Line 10 is OOS

Yh(h,4,5) = 0;

Yh(h,4,6) = -Yh_Hyper_Line_Ser(h,6) - Yh_Hyper_Line_Ser(h,10);

Yh(h,4,7) = 0; % SVC

Yh(h,4,8) = 0;

Yh(h,4,9) = 0;

Yh(h,4,10) = 0;

Yh(h,5,1) = 0;

Yh(h,5,2) = 0;

Yh(h,5,3) = -Yh_Hyper_Line_Ser(h,5) - Yh_Hyper_Line_Ser(h,7);

Yh(h,5,4) = 0;

Yh(h,5,5) = Yh_Load(h,5)+ Y_Filter(h,5) + (Yh_Hyper_Line_Ser(h,5) +Yh_HyperOn2_Line_Shunt(h,5)) + (Yh_Hyper_Line_Ser(h,7) +Yh_HyperOn2_Line_Shunt(h,7)) + (Yh_Hyper_Line_Ser(h,9) +Yh_HyperOn2_Line_Shunt(h,9));

Yh(h,5,6) = 0;

```
    Yh(h,5,7) = 0;

    Yh(h,5,8) = - Yh_Hyper_Line_Ser(h,9);

    Yh(h,5,9) = 0;

    Yh(h,5,10) = 0;

% In Base Case - Some elements connected to Bus 6 is out of service

    Yh(h,6,1) = 0;

    Yh(h,6,2) = 0;

    Yh(h,6,3) = - Yh_Hyper_Line_Ser(h,8);

    % Line 9 is out of service

    Yh(h,6,4) = -Yh_Hyper_Line_Ser(h,6) - Yh_Hyper_Line_Ser(h,10);

    Yh(h,6,5) = 0;

    Yh(h,6,6) =  Yh_Load(h,6)+ Y_Filter(h,6) + (Yh_Hyper_Line_Ser(h,6)
+Yh_HyperOn2_Line_Shunt(h,6)) + (Yh_Hyper_Line_Ser(h,8) +Yh_HyperOn2_Line_Shunt(h,8)) +
(Yh_Hyper_Line_Ser(h,10) +Yh_HyperOn2_Line_Shunt(h,10))+ (Yh_Hyper_Line_Ser(h,12)
+Yh_HyperOn2_Line_Shunt(h,12));

    Yh(h,6,7) = 0;

    Yh(h,6,8) = 0;

    Yh(h,6,9) = 0;

    Yh(h,6,10) = - Yh_Hyper_Line_Ser(h,12);

% SVC still need to be modelled

    Yh(h,7,1) = -(Yh_SVC_TFMR(h) / n_SVCTFMR);   % ie.  Y/n that is the series component only

    Yh(h,7,2) = 0;

    Yh(h,7,3) = 0;

    Yh(h,7,4) = 0;

    Yh(h,7,5) = 0;

    Yh(h,7,6) = 0;

    Yh(h,7,7) = Yh_SVC_TFMR(h) + Yh_SVC(h); % With SVC TFMR @ bus 7= Y/n + (Y - Y/n) = Y
(From Transformer LV Side);

    Yh(h,7,8) = 0;

    Yh(h,7,9) = 0;

    Yh(h,7,10) = 0;

    Yh(h,8,1) = 0;
```

Yh(h,8,2) = 0;

Yh(h,8,3) = 0;

Yh(h,8,4) = 0;

Yh(h,8,5) = -Yh_Hyper_Line_Ser(h,9);

Yh(h,8,6) = 0;

Yh(h,8,7) = 0;

Yh(h,8,8) = Yh_Load(h,8) + (Yh_Hyper_Line_Ser(h,9) +Yh_HyperOn2_Line_Shunt(h,9)); % Generator #8 is currently modelled with 5% Load

Yh(h,8,9) = 0;

Yh(h,8,10) = 0;

Yh(h,9,1) = 0;

Yh(h,9,2) = 0;

Yh(h,9,3) = -Yh_Hyper_Line_Ser(h,11);

Yh(h,9,4) = 0;

Yh(h,9,5) = 0;

Yh(h,9,6) = 0;

Yh(h,9,7) = 0;

Yh(h,9,8) = 0;

Yh(h,9,9) = Yh_Load(h,9) + (Yh_Hyper_Line_Ser(h,11) +Yh_HyperOn2_Line_Shunt(h,11)); % Generator #9 is currently modelled with 5% Load

Yh(h,9,10) = 0;

Yh(h,10,1) = 0;

Yh(h,10,2) = 0;

Yh(h,10,3) = 0;

Yh(h,10,4) = 0;

Yh(h,10,5) = 0;

Yh(h,10,6) = -Yh_Hyper_Line_Ser(h,12);

Yh(h,10,7) = 0;

Yh(h,10,8) = 0;

Yh(h,10,9) = 0;

```
  Yh(h,10,10) =  Yh_Load(h,10) + (Yh_Hyper_Line_Ser(h,12) +Yh_HyperOn2_Line_Shunt(h,12)); % Generator #10 is currently modelled with 5% Load

  %   Yh_Temp = squeeze(Yh(h,:,:))

% Calculate Harmonic Impedance (CIGRE Model)

 Zh_Temp = inv(squeeze(Yh(h,:,:)));

 % store the 2-D array back in 3-D array (1st dimension is harmonic order)

 Zh(h,:,:) = Zh_Temp;

% Define Alpha Constants (Summation Law) as per indicative value of summartion law in IEC 61000-3-6

  if (h/10) < 5

    Alpha = 1.0;

  elseif ((h/10) >= 5) && ((h/10) <=10)

    Alpha = 1.4;

  else

    Alpha = 2.0;

  end

% Define Harmonics Planning Levels as per Table 2 of IEC/TR 61000.3.6:2008

% h = 2,                                  L_HV_EHV(h) = 1.4

% h = 3,                                  L_HV_EHV(h) = 2.0

% h = 4,                                  L_HV_EHV(h) = 0.8

% h = 5, 7                                L_HV_EHV(h) = 2.0

% h = 6, 8                                L_HV_EHV(h) = 0.4

% h = 9,                                  L_HV_EHV(h) = 1.0

% h = 10,12,14,16,18,20,22,24,26,28,,,50 (Even)        L_HV_EHV(h) = 0.19*(10/h)+0.16

% h = 11, 13                              L_HV_EHV(h) = 1.5

% h = 15,                                 L_HV_EHV(h) = 0.3

% h = 21,27,33,39,45, Odd Harmonics Multiple of 3      L_HV_EHV(h) = 0.2

% h = 17,19,23,25,29,31,,,49 (Odd, non-multiple of 3)   L_HV_EHV(h) = 1.2*(17/h)

% Establish Planning Levels as per Table 2 of IEC/TR 61000.3.6:2008

  HV_EHV_Limit = 0;  % Initialise all interhamonics to 0.

  if ((h/10)==1)
```

```
    HV_EHV_Limit = 0/100; %No harmonic at Fundamental Freq.
  elseif ((h/10)==2)
    HV_EHV_Limit = 1.4/100.0;
  elseif ((h/10)==3)||((h/10)==5) || ((h/10)==7)
    HV_EHV_Limit = 2.0/100.0;
  elseif ((h/10)==4)
    HV_EHV_Limit = 0.8/100.0;
  elseif ((h/10)==6) || ((h/10)==8)
    HV_EHV_Limit = 0.4/100.0;
  elseif ((h/10)==9)
    HV_EHV_Limit = 1.0/100.0;
  elseif ((h/10)==10) || ((h/10)==12) || ((h/10)==14) || ((h/10)==16) || ((h/10)==18) || ((h/10)==20) ||
((h/10)==22) || ((h/10)==24)
    HV_EHV_Limit = (0.19*(10/(h/10))+0.16)/100.0;
  elseif ((h/10)==11) || ((h/10)==13)
    HV_EHV_Limit = 1.5/100.0;
  elseif ((h/10)==15)
    HV_EHV_Limit = 0.3/100.0;
  elseif ((h/10)==21)
    HV_EHV_Limit = 0.2/100.0;
  elseif ((h/10)==17) || ((h/10)==19) || ((h/10)==23) || ((h/10)==25)
    HV_EHV_Limit = 1.2*(17/(h/10))/100.0;
  end
  IEC_Limit(h,1) = HV_EHV_Limit;  % Record Planning Limit for each Harmonic
% Calculate Influence Coefficients
  for p = 1:N_Bus
     for r = 1:N_Bus
        K(h,r,p) = Zh_Temp(p,r)/Zh_Temp(r,r);  % Voltage measured at Node p when Harmonic current
inject at node r result in 1pu voltage at node r
        K_Angle(h,r,p) = angle(K(h,r,p))*(180/pi);
     end
```

```
    end  % End of Influence Coefficients Calcs

%Calculate Maximum global contribution at each bus GhBj based on Shared

%Planning Methodology as in Annex D - P47 of the Standard

    Denominator(1:N_Bus, 1:N_Bus) = 0;      % For Each loop, reset the denominator

    Gh_Temp(1:N_Bus,1:N_Bus) = 0;  % For Each Harmoni, reset Gh_Temp

    BusCount_a = 1;

     for a = 1:N_Bus

        for b = 1:N_Bus

          for c = 1:N_Bus

              Denominator(a,b) = Denominator(a,b) + ((abs(K(h,c,b)))^Alpha)*(St(c)-St_Spare(c));  % e.g.
Denominator of Equation (D.8) of IEC Annex D (page 47) with Proposed AUPEC 17 Paper (Subtraction
of St_Spare)

          end

          Gh_Temp(a,b) = ((St(a) / Denominator(a,b))^(1/Alpha))*HV_EHV_Limit;   % Equation (D.9) of
Annex D Page 47 of IEC Report

          if b>1                                  % Find The Smallest value of Gh that satisfy all N Bus
conditions.

              if Gh_Temp(a,b) > Gh_Temp(a,b-1)

                  Gh_Temp(a,b) = Gh_Temp(a,b-1);          % Set the last Gh to the smallest value of Gh

              end

          end

        end

        Gh(h,a) = abs(Gh_Temp(a,b));                    % Store the value of Smallest Gh of each bus at each
harmonic into Gh (h,NBUs) matrix

    % This is needed only in the code to avoid the situation where all Sts

    % are set to zero and the ratio of (St(a) / Demoninator) > 1, which should not exist in real systems, but
in simulation

    % this situation can occur due to accidental / unrealistic simulation.

        if Gh(h,a)> HV_EHV_Limit

           Gh(h,a)= HV_EHV_Limit;

        end

% Allocated Currents and Voltages - Individual Emission of each load based on load size, total supply
capacity (St) and Maximum contributon allowed at each bus
```

```
 % and calculate total harmonic injection at each bus

        if (a==1) % Bus 1 has both Loads Si(11) and Si(12) therefore they must be allocated as individual loads

              % Emission of load 11

              % Gh(1):  Maximum global contributon to the h th harmonic voltage of the

              % distorting installations that can be connected to Bus 1

              % St(1) Total supply capacity at bus 1

              % Si(11) load 11 and Si(12) are installed at bus 1

              % EUhi_Load_11 = Emission limit of load 11

              % EIhi_Load_11 = Hamonic Current Emission Limit of load 11

               EUhi_Load_11(h) = (((Gh(h,a))^(Alpha)) * (Si(11) / St(a)))^(1/Alpha);

    %           EIhi_Load_11(h) = EUhi_Load_11(h) / abs(Zh(h,a,a));

              % Allocate Load 12

               EUhi_Load_12(h) = (((Gh(h,a))^(Alpha) - (EUhi_Load_11(h))^(Alpha)) * (Si(12) / (St(a)-Si(11))))^(1/Alpha);

    %          EIhi_Load_12(h) = EUhi_Load_12(h) / abs(Zh(h,a,a));

    %  Allocate For Spare Capacity:

               EUhi_SpareCapacity(h,a) = (((Gh(h,a))^Alpha - (EUhi_Load_11(h))^Alpha - (EUhi_Load_12(h))^Alpha) * (St_Spare(a) / (St(a)-Si(11)-Si(12))))^(1/Alpha);

               EUhi(h,a) = ((EUhi_Load_11(h))^Alpha + (EUhi_Load_12(h))^Alpha + (EUhi_SpareCapacity(h,a))^Alpha)^(1/Alpha);

               EIhi(h,a) = EUhi(h,a) / abs(Zh(h,a,a));

              % Total Current Allocation at bus 1:  EIhi1 = EIhi11 + EIhi12 (Currents

              % allocated to load 11 and load 12 - both connected to bus 1

              % 06/06/2017

    %          EIhi(h,a) = EIhi_Load_11(h) + EIhi_Load_12(h);

    %          EUhi(h,a) = Gh(h,a) * ((Si(11)+Si(12)) / St(a))^(1/Alpha);

    %          EIhi(h,a) = EUhi(h,a) / abs(Zh(h,a,a));

              % Allocated voltage to bus 1  V = abs(Zh_Temp(1,1)*EIhi(1)

    %          EUhi(h,a) = EIhi(h,a)* abs(Zh(h,a,a));

        elseif (a==7)  % TCR Currents of existing SVC is worked out based on the non-linear model below - No allocation for bus 7 is required (i.e existing SVC)
```

```
if (SVCStat == 1) % If SVC is in service, harmonic emission at bus 1 will be SVC currents in pu

   I1_TCR = I_TCR*((2*(pi-TCR_DelayAngle)- sin(2*pi - 2*TCR_DelayAngle))/pi);    % Fundamental component of TCR Currents, I_TCR = Fully conduting current of TCR

   if ((h/10)==1)

      EIhi(h,a) = I1_TCR /I2_Base;

   elseif ((h/10)==2)||((h/10)==4)||((h/10)==6)||((h/10)==8)||((h/10)==10)||((h/10)==12)||((h/10)==14)||((h/10)==16)||((h/10)==18)||((h/10)==20)||((h/10)==22)||((h/10)==24)   % Even Harmonic generates Non-Characteristic Harmonics

      EIhi(h,a) = (I_TCR*(4/((h/10)*pi)) * TCR_DiffAngle * (sin((h/10)*TCR_DelayAngle))*(sin(TCR_DelayAngle)) )/ I2_Base;

   elseif ((h/10)==3)||((h/10)==5)||((h/10)==7)||((h/10)==9)||((h/10)==11)||((h/10)==13)||((h/10)==15)||((h/10)==17)||((h/10)==19)||((h/10)==21)||((h/10)==23)||((h/10)==25)   % Odd Harmonic generates Characteristic Harmonics

      EIhi(h,a) = (I_TCR*(2/((h/10)*pi))*abs((sin(((h/10)-1)*(pi-TCR_DelayAngle)))/((h/10)-1) - (sin(((h/10)+1)*(pi-TCR_DelayAngle)))/((h/10)+1))) / I2_Base;

   end

else  % if SVC is not in service, Current Emission from bus 7 will be zero

    EIhi(h,a) = 0;

end % enf od svc stat

else  % Allocated Currents (EIhi) and Voltages (EUhi) for each bus 2 to bus 6.

   EUhi(h,a) = Gh(h,a) * (Si(a) / St(a))^(1/Alpha);    %   e.g.  EUhi2 = Gh(2) * (Si(2) / St(2))^(1/Alpha);

   EUhi_SpareCapacity(h,a) = (((Gh(h,a))^Alpha - (EUhi(h,a))^Alpha) * (St_Spare(a) / (St(a)-Si(a))))^(1/Alpha);

   EUhi(h,a) = ((EUhi(h,a))^Alpha + (EUhi_SpareCapacity(h,a))^Alpha)^(1/Alpha);

   EIhi(h,a) = EUhi(h,a) / abs(Zh(h,a,a));            %   e.g.  EIhi2 = EUhi2 / abs(Zh_Temp(2,2));

end

if (Existing_Currents ==1)       % If use harmoinc currents previously allocated, all harmonic allocations from bus 1 to bus 7 will be overwritten;

   if (a==1)

      if ((h/10)==1) ||((h/10)==2)||((h/10)==3)||((h/10)==4)||((h/10)==5)||((h/10)==6)||((h/10)==7)||((h/10)==8)||((h/10)==9)||((h/10)==10)||((h/10)==11)||((h/10)==12)||((h/10)==13)||((h/10)==14)||((h/10)==15)||((h/10)==16)||((h/10)==17)||((h/10)==18)||((h/10)==19)||((h/10)==20)||((h/10)==21)||((h/10)==22)||((h/10)==23)||((h/10)==24)||((h/10)==25)
```

```
                 EIhi(h,a) =  Bus1_PastHarmData((h/10)*3);  %   This line will overwrite all harmonic
allocations above from bus 1 ;

                end

            elseif (a == 2)  % Use exsiting allocations for injection at Bus 1 to 8

                if ((h/10)==1)
||((h/10)==2)||((h/10)==3)||((h/10)==4)||((h/10)==5)||((h/10)==6)||((h/10)==7)||((h/10)==8)||((h/10)==9)||((
h/10)==10)||((h/10)==11)||((h/10)==12)||((h/10)==13)||((h/10)==14)||((h/10)==15)||((h/10)==16)||((h/10)=
=17)||((h/10)==18)||((h/10)==19)||((h/10)==20)||((h/10)==21)||((h/10)==22)||((h/10)==23)||((h/10)==24)||((
h/10)==25)

                 EIhi(h,a) =  Bus2_PastHarmData((h/10)*3);  %   This line will overwrite all harmonic
allocations above from bus 2;

                end

            elseif (a == 3)  % Use exsiting allocations for injection at Bus 1 to 8

                if ((h/10)==1)
||((h/10)==2)||((h/10)==3)||((h/10)==4)||((h/10)==5)||((h/10)==6)||((h/10)==7)||((h/10)==8)||((h/10)==9)||((
h/10)==10)||((h/10)==11)||((h/10)==12)||((h/10)==13)||((h/10)==14)||((h/10)==15)||((h/10)==16)||((h/10)=
=17)||((h/10)==18)||((h/10)==19)||((h/10)==20)||((h/10)==21)||((h/10)==22)||((h/10)==23)||((h/10)==24)||((
h/10)==25)

                 EIhi(h,a) =  Bus3_PastHarmData((h/10)*3);  %   This line will overwrite all harmonic
allocations above from bus 3;

                end

            elseif (a == 4)  % Use exsiting allocations for injection at Bus 1 to 8

                if ((h/10)==1)
||((h/10)==2)||((h/10)==3)||((h/10)==4)||((h/10)==5)||((h/10)==6)||((h/10)==7)||((h/10)==8)||((h/10)==9)||((
h/10)==10)||((h/10)==11)||((h/10)==12)||((h/10)==13)||((h/10)==14)||((h/10)==15)||((h/10)==16)||((h/10)=
=17)||((h/10)==18)||((h/10)==19)||((h/10)==20)||((h/10)==21)||((h/10)==22)||((h/10)==23)||((h/10)==24)||((
h/10)==25)

                 EIhi(h,a) =  Bus4_PastHarmData((h/10)*3);  %   This line will overwrite all harmonic
allocations above from bus 4;

                end

            elseif (a == 5)  % Use exsiting allocations for injection at Bus 1 to 8

                if ((h/10)==1)
||((h/10)==2)||((h/10)==3)||((h/10)==4)||((h/10)==5)||((h/10)==6)||((h/10)==7)||((h/10)==8)||((h/10)==9)||((
h/10)==10)||((h/10)==11)||((h/10)==12)||((h/10)==13)||((h/10)==14)||((h/10)==15)||((h/10)==16)||((h/10)=
=17)||((h/10)==18)||((h/10)==19)||((h/10)==20)||((h/10)==21)||((h/10)==22)||((h/10)==23)||((h/10)==24)||((
h/10)==25)

                 EIhi(h,a) =  Bus5_PastHarmData((h/10)*3);  %   This line will overwrite all harmonic
allocations above from bus 5;

                end

            elseif (a == 6)  % Use exsiting allocations for injection at Bus 1 to 8
```

```
                if ((h/10)==1)
||((h/10)==2)||((h/10)==3)||((h/10)==4)||((h/10)==5)||((h/10)==6)||((h/10)==7)||((h/10)==8)||((h/10)==9)||((
h/10)==10)||((h/10)==11)||((h/10)==12)||((h/10)==13)||((h/10)==14)||((h/10)==15)||((h/10)==16)||((h/10)=
=17)||((h/10)==18)||((h/10)==19)||((h/10)==20)||((h/10)==21)||((h/10)==22)||((h/10)==23)||((h/10)==24)||((
h/10)==25)

                  EIhi(h,a) =  Bus6_PastHarmData((h/10)*3);  %   This line will overwrite all harmonic
allocations above from bus 6;

                end

            elseif (a == 7)  % Use exsiting allocations for injection at Bus 1 to 8

                if ((h/10)==1)
||((h/10)==2)||((h/10)==3)||((h/10)==4)||((h/10)==5)||((h/10)==6)||((h/10)==7)||((h/10)==8)||((h/10)==9)||((
h/10)==10)||((h/10)==11)||((h/10)==12)||((h/10)==13)||((h/10)==14)||((h/10)==15)||((h/10)==16)||((h/10)=
=17)||((h/10)==18)||((h/10)==19)||((h/10)==20)||((h/10)==21)||((h/10)==22)||((h/10)==23)||((h/10)==24)||((
h/10)==25)

                  EIhi(h,a) =  Bus7_PastHarmData((h/10)*3);  %   This line will overwrite all harmonic
allocations above from bus 7;

                end

            elseif (a == 8)  % Use exsiting allocations for injection at Bus 1 to 8

                if ((h/10)==1)
||((h/10)==2)||((h/10)==3)||((h/10)==4)||((h/10)==5)||((h/10)==6)||((h/10)==7)||((h/10)==8)||((h/10)==9)||((
h/10)==10)||((h/10)==11)||((h/10)==12)||((h/10)==13)||((h/10)==14)||((h/10)==15)||((h/10)==16)||((h/10)=
=17)||((h/10)==18)||((h/10)==19)||((h/10)==20)||((h/10)==21)||((h/10)==22)||((h/10)==23)||((h/10)==24)||((
h/10)==25)

                  EIhi(h,a) =  Bus8_PastHarmData((h/10)*3);  %   This line will overwrite all harmonic
allocations above from bus 8;

                end

            elseif (a == 9)  % Use exsiting allocations for injection at Bus 1 to 8

                if ((h/10)==1)
||((h/10)==2)||((h/10)==3)||((h/10)==4)||((h/10)==5)||((h/10)==6)||((h/10)==7)||((h/10)==8)||((h/10)==9)||((
h/10)==10)||((h/10)==11)||((h/10)==12)||((h/10)==13)||((h/10)==14)||((h/10)==15)||((h/10)==16)||((h/10)=
=17)||((h/10)==18)||((h/10)==19)||((h/10)==20)||((h/10)==21)||((h/10)==22)||((h/10)==23)||((h/10)==24)||((
h/10)==25)

                  EIhi(h,a) =  Bus9_PastHarmData((h/10)*3);  %   This line will overwrite all harmonic
allocations above from bus 9;

                end

            end

        end

    end

   for m = 1:N_Bus

      Vh_Temp = 0;                  % Reset for each bus
```

```
    Vh_NoAlpha_Temp = 0;                    % Reset for each bus
    for n = 1:N_Bus
        Vh_Temp = Vh_Temp + (abs(Zh(h,m,n))*EIhi(h,n))^Alpha;
        Vh_NoAlpha_Temp = Vh_NoAlpha_Temp + (Zh(h,m,n)*EIhi(h,n));
    end
    Vh(h,m) = Vh_Temp^(1/Alpha);        % Calculate Harmonic Voltages at Each Bus ;
    Vh_NoAlpha(h,m) = Vh_NoAlpha_Temp;
  end
  debugcodes = 0;
  if debugcodes == 1
     HV_EHV_Limit;
     Gh(h,2);
     abs(Zh(h,2,2));
     EUhi(h,:);
     EIhi(h,:);
     Vh(h,:);
  end % end debugcodes
     K = squeeze(K(h,:,:));
     K_Angle = squeeze(K_Angle(h,:,:));
 testmode =0;
if testmode == 0
    if ((h/10)==1)
||((h/10)==2)||((h/10)==3)||((h/10)==4)||((h/10)==5)||((h/10)==6)||((h/10)==7)||((h/10)==8)||((h/10)==9)||((
h/10)==10)||((h/10)==11)||((h/10)==12)||((h/10)==13)||((h/10)==14)||((h/10)==15)||((h/10)==16)||((h/10)=
=17)||((h/10)==18)||((h/10)==19)||((h/10)==20)||((h/10)==21)||((h/10)==22)||((h/10)==23)||((h/10)==24)||((
h/10)==25)
     h1 = h/10;
    % Write Influence_Coefficient to Excell Sheets - Sheet1 - h=1,,,, Sheet25 - h = 25
     xlswrite('Dev_Influence_Coefficient', real(K), h1, 'B3');
     xlswrite('Dev_Influence_Coefficient', imag(K), h1, 'N3');
     xlswrite('Dev_Influence_Coefficient', abs(K), h1, 'B16');
     xlswrite('Dev_Influence_Coefficient', K_Angle, h1, 'N16');
```

```
% Write Impedance Matrix to Excell Sheets - Sheet1 - h=1,,,, Sheet25 - h = 25
 xlswrite('Dev_Harmonic_Impedance', real(Zh_Temp), h1, 'B3');
 xlswrite('Dev_Harmonic_Impedance', imag(Zh_Temp), h1, 'N3');
 xlswrite('Dev_Harmonic_Impedance', abs(Zh_Temp), h1, 'B16');
 xlswrite('Dev_Harmonic_Impedance', angle(Zh_Temp)*(180/pi), h1, 'N16');
 % Write Allocated Harmonic Voltages, Bus Impedance and Currents Using IEC Method
%Voltage
 xlswrite('Dev_Harmonic_Allocation', h1, h1, 'A5');  % Print all values to sheet 1
 xlswrite('Dev_Harmonic_Allocation', abs(EUhi(h,1)), h1, 'C5');
 xlswrite('Dev_Harmonic_Allocation', abs(EUhi(h,2)), h1, 'E5');
 xlswrite('Dev_Harmonic_Allocation', abs(EUhi(h,3)), h1, 'G5');
 xlswrite('Dev_Harmonic_Allocation', abs(EUhi(h,4)), h1, 'I5');
 xlswrite('Dev_Harmonic_Allocation', abs(EUhi(h,5)), h1, 'K5');
 xlswrite('Dev_Harmonic_Allocation', abs(EUhi(h,6)), h1, 'M5');
 xlswrite('Dev_Harmonic_Allocation', abs(EUhi(h,7)), h1, 'O5');
 xlswrite('Dev_Harmonic_Allocation', abs(EUhi(h,8)), h1, 'Q5');
 xlswrite('Dev_Harmonic_Allocation', abs(EUhi(h,9)), h1, 'S5');
 xlswrite('Dev_Harmonic_Allocation', abs(EUhi(h,10)), h1, 'U5');
 xlswrite('Dev_Harmonic_Allocation', angle(EUhi(h,1))*(180/pi), h1, 'D5');
 xlswrite('Dev_Harmonic_Allocation', angle(EUhi(h,2))*(180/pi), h1, 'F5');
 xlswrite('Dev_Harmonic_Allocation', angle(EUhi(h,3))*(180/pi), h1, 'H5');
 xlswrite('Dev_Harmonic_Allocation', angle(EUhi(h,4))*(180/pi), h1, 'J5');
 xlswrite('Dev_Harmonic_Allocation', angle(EUhi(h,5))*(180/pi), h1, 'L5');
 xlswrite('Dev_Harmonic_Allocation', angle(EUhi(h,6))*(180/pi), h1, 'N5');
 xlswrite('Dev_Harmonic_Allocation', angle(EUhi(h,7))*(180/pi), h1, 'P5');
 xlswrite('Dev_Harmonic_Allocation', angle(EUhi(h,8))*(180/pi), h1, 'R5');
 xlswrite('Dev_Harmonic_Allocation', angle(EUhi(h,9))*(180/pi), h1, 'T5');
 xlswrite('Dev_Harmonic_Allocation', angle(EUhi(h,10))*(180/pi), h1, 'V5');
 % Print Allocated Voltages of Load 11
 xlswrite('Dev_Harmonic_Allocation', abs(EUhi_Load_11(h)), h1, 'AA5');
```

```
    xlswrite('Dev_Harmonic_Allocation', abs(EUhi_Load_12(h)), h1, 'AC5');

    xlswrite('Dev_Harmonic_Allocation', abs(EUhi_SpareCapacity(h)), h1, 'AE5');

    xlswrite('Dev_Harmonic_Allocation', angle(EUhi_Load_11(h))*(180/pi), h1, 'AB5');

    xlswrite('Dev_Harmonic_Allocation', angle(EUhi_Load_12(h))*(180/pi), h1, 'AD5');

    xlswrite('Dev_Harmonic_Allocation', angle(EUhi_SpareCapacity(h))*(180/pi), h1, 'AF5');

%Impedance

    xlswrite('Dev_Harmonic_Allocation', abs(Zh(h,1,1)), h1, 'C6');

    xlswrite('Dev_Harmonic_Allocation', abs(Zh(h,2,2)), h1, 'E6');

    xlswrite('Dev_Harmonic_Allocation', abs(Zh(h,3,3)), h1, 'G6');

    xlswrite('Dev_Harmonic_Allocation', abs(Zh(h,4,4)), h1, 'I6');

    xlswrite('Dev_Harmonic_Allocation', abs(Zh(h,5,5)), h1, 'K6');

    xlswrite('Dev_Harmonic_Allocation', abs(Zh(h,6,6)), h1, 'M6');

    xlswrite('Dev_Harmonic_Allocation', abs(Zh(h,7,7)), h1, 'O6');

    xlswrite('Dev_Harmonic_Allocation', abs(Zh(h,8,8)), h1, 'Q6');

    xlswrite('Dev_Harmonic_Allocation', abs(Zh(h,9,9)), h1, 'S6');

    xlswrite('Dev_Harmonic_Allocation', abs(Zh(h,10,10)), h1, 'U6');

    xlswrite('Dev_Harmonic_Allocation', angle(Zh(h,1,1))*(180/pi), h1, 'D6');

    xlswrite('Dev_Harmonic_Allocation', angle(Zh(h,2,2))*(180/pi), h1, 'F6');

    xlswrite('Dev_Harmonic_Allocation', angle(Zh(h,3,3))*(180/pi), h1, 'H6');

    xlswrite('Dev_Harmonic_Allocation', angle(Zh(h,4,4))*(180/pi), h1, 'J6');

    xlswrite('Dev_Harmonic_Allocation', angle(Zh(h,5,5))*(180/pi), h1, 'L6');

    xlswrite('Dev_Harmonic_Allocation', angle(Zh(h,6,6))*(180/pi), h1, 'N6');

    xlswrite('Dev_Harmonic_Allocation', angle(Zh(h,7,7))*(180/pi), h1, 'P6');

    xlswrite('Dev_Harmonic_Allocation', angle(Zh(h,8,8))*(180/pi), h1, 'R6');

    xlswrite('Dev_Harmonic_Allocation', angle(Zh(h,9,9))*(180/pi), h1, 'T6');

    xlswrite('Dev_Harmonic_Allocation', angle(Zh(h,10,10))*(180/pi), h1, 'V6');

%Current

    xlswrite('Dev_Harmonic_Allocation', abs(EIhi(h,1)), h1, 'C7');

    xlswrite('Dev_Harmonic_Allocation', abs(EIhi(h,2)), h1, 'E7');

    xlswrite('Dev_Harmonic_Allocation', abs(EIhi(h,3)), h1, 'G7');
```

```
xlswrite('Dev_Harmonic_Allocation', abs(EIhi(h,4)), h1, 'I7');
xlswrite('Dev_Harmonic_Allocation', abs(EIhi(h,5)), h1, 'K7');
xlswrite('Dev_Harmonic_Allocation', abs(EIhi(h,6)), h1, 'M7');
xlswrite('Dev_Harmonic_Allocation', abs(EIhi(h,7)), h1, 'O7');
xlswrite('Dev_Harmonic_Allocation', abs(EIhi(h,8)), h1, 'Q7');
xlswrite('Dev_Harmonic_Allocation', abs(EIhi(h,9)), h1, 'S7');
xlswrite('Dev_Harmonic_Allocation', abs(EIhi(h,10)), h1, 'U7');
xlswrite('Dev_Harmonic_Allocation', angle(EIhi(h,1))*(180/pi), h1, 'D7');
xlswrite('Dev_Harmonic_Allocation', angle(EIhi(h,2))*(180/pi), h1, 'F7');
xlswrite('Dev_Harmonic_Allocation', angle(EIhi(h,3))*(180/pi), h1, 'H7');
xlswrite('Dev_Harmonic_Allocation', angle(EIhi(h,4))*(180/pi), h1, 'J7');
xlswrite('Dev_Harmonic_Allocation', angle(EIhi(h,5))*(180/pi), h1, 'L7');
xlswrite('Dev_Harmonic_Allocation', angle(EIhi(h,6))*(180/pi), h1, 'N7');
xlswrite('Dev_Harmonic_Allocation', angle(EIhi(h,7))*(180/pi), h1, 'P7');
xlswrite('Dev_Harmonic_Allocation', angle(EIhi(h,8))*(180/pi), h1, 'R7');
xlswrite('Dev_Harmonic_Allocation', angle(EIhi(h,9))*(180/pi), h1, 'T7');
xlswrite('Dev_Harmonic_Allocation', angle(EIhi(h,10))*(180/pi), h1, 'V7');
% Write Harmonic Voltages With Alhpa Summation Law of all to Excell Sheet1
xlswrite('Dev_Harmonic_Voltage', h1, h1, 'A4');
xlswrite('Dev_Harmonic_Voltage', abs(Vh(h,1)), h1, 'B4');
xlswrite('Dev_Harmonic_Voltage', abs(Vh(h,2)), h1, 'D4');
xlswrite('Dev_Harmonic_Voltage', abs(Vh(h,3)), h1, 'F4');
xlswrite('Dev_Harmonic_Voltage', abs(Vh(h,4)), h1, 'H4');
xlswrite('Dev_Harmonic_Voltage', abs(Vh(h,5)), h1, 'J4');
xlswrite('Dev_Harmonic_Voltage', abs(Vh(h,6)), h1, 'L4');
xlswrite('Dev_Harmonic_Voltage', abs(Vh(h,7)), h1, 'N4');
xlswrite('Dev_Harmonic_Voltage', abs(Vh(h,8)), h1, 'P4');
xlswrite('Dev_Harmonic_Voltage', abs(Vh(h,9)), h1, 'R4');
xlswrite('Dev_Harmonic_Voltage', abs(Vh(h,10)), h1, 'T4');
xlswrite('Dev_Harmonic_Voltage', angle(Vh(h,1))*(180/pi), h1, 'C4');
```

```
    xlswrite('Dev_Harmonic_Voltage', angle(Vh(h,2))*(180/pi), h1, 'E4');
    xlswrite('Dev_Harmonic_Voltage', angle(Vh(h,3))*(180/pi), h1, 'G4');
    xlswrite('Dev_Harmonic_Voltage', angle(Vh(h,4))*(180/pi), h1, 'I4');
    xlswrite('Dev_Harmonic_Voltage', angle(Vh(h,5))*(180/pi), h1, 'K4');
    xlswrite('Dev_Harmonic_Voltage', angle(Vh(h,6))*(180/pi), h1, 'M4');
    xlswrite('Dev_Harmonic_Voltage', angle(Vh(h,7))*(180/pi), h1, 'O4');
    xlswrite('Dev_Harmonic_Voltage', angle(Vh(h,8))*(180/pi), h1, 'Q4');
    xlswrite('Dev_Harmonic_Voltage', angle(Vh(h,9))*(180/pi), h1, 'S4');
    xlswrite('Dev_Harmonic_Voltage', angle(Vh(h,10))*(180/pi), h1, 'U4');
% Voltage Assessment with impedance angle and no alpha summation
    xlswrite('Dev_Harmonic_Voltage', abs(Vh_NoAlpha(h,1)), h1, 'W4');
    xlswrite('Dev_Harmonic_Voltage', abs(Vh_NoAlpha(h,2)), h1, 'Y4');
    xlswrite('Dev_Harmonic_Voltage', abs(Vh_NoAlpha(h,3)), h1, 'AA4');
    xlswrite('Dev_Harmonic_Voltage', abs(Vh_NoAlpha(h,4)), h1, 'AC4');
    xlswrite('Dev_Harmonic_Voltage', abs(Vh_NoAlpha(h,5)), h1, 'AE4');
    xlswrite('Dev_Harmonic_Voltage', abs(Vh_NoAlpha(h,6)), h1, 'AG4');
    xlswrite('Dev_Harmonic_Voltage', abs(Vh_NoAlpha(h,7)), h1, 'AI4');
    xlswrite('Dev_Harmonic_Voltage', abs(Vh_NoAlpha(h,8)), h1, 'AK4');
    xlswrite('Dev_Harmonic_Voltage', abs(Vh_NoAlpha(h,9)), h1, 'AM4');
    xlswrite('Dev_Harmonic_Voltage', abs(Vh_NoAlpha(h,10)), h1, 'AO4');
    xlswrite('Dev_Harmonic_Voltage', angle(Vh_NoAlpha(h,1))*(180/pi), h1, 'X4');
    xlswrite('Dev_Harmonic_Voltage', angle(Vh_NoAlpha(h,2))*(180/pi), h1, 'Z4');
    xlswrite('Dev_Harmonic_Voltage', angle(Vh_NoAlpha(h,3))*(180/pi), h1, 'AB4');
    xlswrite('Dev_Harmonic_Voltage', angle(Vh_NoAlpha(h,4))*(180/pi), h1, 'AD4');
    xlswrite('Dev_Harmonic_Voltage', angle(Vh_NoAlpha(h,5))*(180/pi), h1, 'AF4');
    xlswrite('Dev_Harmonic_Voltage', angle(Vh_NoAlpha(h,6))*(180/pi), h1, 'AH4');
    xlswrite('Dev_Harmonic_Voltage', angle(Vh_NoAlpha(h,7))*(180/pi), h1, 'AJ4');
    xlswrite('Dev_Harmonic_Voltage', angle(Vh_NoAlpha(h,8))*(180/pi), h1, 'AL4');
    xlswrite('Dev_Harmonic_Voltage', angle(Vh_NoAlpha(h,9))*(180/pi), h1, 'AN4');
    xlswrite('Dev_Harmonic_Voltage', angle(Vh_NoAlpha(h,10))*(180/pi), h1, 'AP4');
```

```
    end % End of h==....
  end %(of test mode
end      % Main harmonic order For Loop
%Plot TCR Current to observe if TCR model is correct
 figure
 freq=1:1:k_h;
 plot(freq,abs(EIhi(:,7)),'r', 'LineWidth', 2.5), hold on % Plot TCR Currents at bus 7
 grid
 title('SVC TCR Currents inject into Bus 7 (14.1 kV Bus)')
 legend('TCR Currents')
 xlabel('Harmonic Order, h')
 ylabel('TCR Currents, PU')
 set(gca,'XTick',10:10:k_h)
 set(gca,'XTickLabel',{'1','2','3','4','5',
'6','7','8','9','10','11','12','13','14','15','16','17','18','19','20','21','22','23','24','25'})
 %Plot Harmonic Self-Impedance
 figure
 freq=1:1:k_h;
 plot(freq,abs(Zh(:,1,1)),'r', 'LineWidth', 2.5), hold on % Bus 1
 plot(freq,abs(Zh(:,2,2)),'b', 'LineWidth', 2.5) % Bus 2
 plot(freq,abs(Zh(:,3,3)),'g', 'LineWidth', 2.5) % Bus 3
 plot(freq,abs(Zh(:,4,4)),'c', 'LineWidth', 2.5) % Bus 4
 plot(freq,abs(Zh(:,5,5)),'m', 'LineWidth', 2.5) % Bus 5
 plot(freq,abs(Zh(:,6,6)),'k', 'LineWidth', 2.5) % Bus 6
 plot(freq,abs(Zh(:,7,7)),'y', 'LineWidth', 2.5) % Bus 7
 plot(freq,abs(Zh(:,8,8)),'r:*', 'LineWidth', 1.5) % Bus 8
 plot(freq,abs(Zh(:,9,9)),'b:+', 'LineWidth', 1.5) % Bus 9
 plot(freq,abs(Zh(:,10,10)),'g:x', 'LineWidth', 1.5) % Bus 10
  grid
 title('Harmonic Impedance vs Harmonic Order (Freq) - 10 Bus')
```

```
legend('Bus 1 Zh','Bus 2 Zh','Bus 3 Zh','Bus 4 Zh','Bus 5 Zh','Bus 6 Zh','Bus 7 Zh','Bus 8 Zh','Bus 9 Zh','Bus 10 Zh')

xlabel('Harmonic Order, h')

ylabel('Harmonic Impedance, PU')

set(gca,'XTick',10:10:k_h)

set(gca,'XTickLabel',{'1','2','3','4','5', '6','7','8','9','10','11','12','13','14','15','16','17','18','19','20','21','22','23','24','25'})

%Plot Harmonic Self-Impedance Angle

figure

freq=1:1:k_h;

plot(freq,angle(Zh(:,1,1))*(180/pi),'r', 'LineWidth', 2.5), hold on % Bus 1

plot(freq,angle(Zh(:,2,2))*(180/pi),'b', 'LineWidth', 2.5) % Bus 2

plot(freq,angle(Zh(:,3,3))*(180/pi),'g', 'LineWidth', 2.5) % Bus 3

plot(freq,angle(Zh(:,4,4))*(180/pi),'c', 'LineWidth', 2.5) % Bus 4

plot(freq,angle(Zh(:,5,5))*(180/pi),'m', 'LineWidth', 2.5) % Bus 5

plot(freq,angle(Zh(:,6,6))*(180/pi),'k', 'LineWidth', 2.5) % Bus 6

plot(freq,angle(Zh(:,7,7))*(180/pi),'y', 'LineWidth', 2.5) % Bus 7

plot(freq,angle(Zh(:,8,8))*(180/pi),'r:*', 'LineWidth', 1.5) % Bus 8

plot(freq,angle(Zh(:,9,9))*(180/pi),'b:+', 'LineWidth', 1.5) % Bus 9

plot(freq,angle(Zh(:,10,10))*(180/pi),'g:x', 'LineWidth', 1.5) % Bus 10

grid

title('Impedance Angle vs Harmonic Order (Freq) - 7 Bus')

legend('Bus 1 Zh','Bus 2 Zh','Bus 3 Zh','Bus 4 Zh','Bus 5 Zh','Bus 6 Zh','Bus 7 Zh','Bus 8 Zh','Bus 9 Zh','Bus 10 Zh')

xlabel('Harmonic Order, h')

ylabel('Harmonic Impedance, PU')

set(gca,'XTick',10:10:k_h)

set(gca,'XTickLabel',{'1','2','3','4','5', '6','7','8','9','10','11','12','13','14','15','16','17','18','19','20','21','22','23','24','25'})

% Plot Harmonic voltages at All buses

figure

freq=1:1:k_h;
```

```
plot(freq,abs(Vh(:,1)),'r', 'LineWidth', 1.5), hold on % Bus 1

plot(freq,abs(Vh(:,2)),'b', 'LineWidth', 1.5) % Bus 2

plot(freq,abs(Vh(:,3)),'g', 'LineWidth', 1.5) % Bus 3

plot(freq,abs(Vh(:,4)),'c', 'LineWidth', 1.5) % Bus 4

plot(freq,abs(Vh(:,5)),'m', 'LineWidth', 1.5) % Bus 5

plot(freq,abs(Vh(:,6)),'k', 'LineWidth', 1.5) % Bus 6

plot(freq,abs(Vh(:,7)),'y', 'LineWidth', 1.5) % Bus 7

plot(freq,abs(Vh(:,8)),'r:*', 'LineWidth', 1.5) % Bus 8

plot(freq,abs(Vh(:,9)),'b:+', 'LineWidth', 1.5) % Bus 9

plot(freq,abs(Vh(:,10)),'g:x', 'LineWidth', 1.5) % Bus 10

 plot(freq,IEC_Limit(:,1),'r', 'LineWidth', 3.5) % Planning Limit

grid

title('Harmonic Voltages at 7 Buses')

legend('V1','V2','V3','V4','V5','V6','V7', 'V8','V9','V10','Limit')

xlabel('Harmonic Order, h')

ylabel('Harmonic Voltage, PU')

set(gca,'XTick',10:10:k_h)

set(gca,'XTickLabel',{'1','2','3','4','5',
'6','7','8','9','10','11','12','13','14','15','16','17','18','19','20','21','22','23','24','25'})

% Plot Harmonic voltages at All buses

figure

freq= 1:1:k_h;

plot(freq,abs(Vh_NoAlpha(:,1)),'r', 'LineWidth', 1.5), hold on % Bus 1

plot(freq,abs(Vh_NoAlpha(:,2)),'b', 'LineWidth', 1.5) % Bus 2

plot(freq,abs(Vh_NoAlpha(:,3)),'g', 'LineWidth', 1.5) % Bus 3

plot(freq,abs(Vh_NoAlpha(:,4)),'c', 'LineWidth', 1.5) % Bus 4

plot(freq,abs(Vh_NoAlpha(:,5)),'m', 'LineWidth', 1.5) % Bus 5

plot(freq,abs(Vh_NoAlpha(:,6)),'k', 'LineWidth', 1.5) % Bus 6

plot(freq,abs(Vh_NoAlpha(:,7)),'y', 'LineWidth', 1.5) % Bus 7

plot(freq,abs(Vh_NoAlpha(:,8)),'r:*', 'LineWidth', 1.5) % Bus 8
```

```
plot(freq,abs(Vh_NoAlpha(:,9)),'b:+', 'LineWidth', 1.5) % Bus 9

plot(freq,abs(Vh_NoAlpha(:,10)),'g:x', 'LineWidth', 1.5) % Bus 10

 plot(freq,IEC_Limit(:,1),'r', 'LineWidth', 3.5) % Planning Limit

grid

title('Harmonic Voltages at 7 Buses - No Alpha')

legend('V1','V2','V3','V4','V5','V6','V7', 'V8', 'V9', 'V10', 'Limit' )

xlabel('Harmonic Order, h')

ylabel('Harmonic Voltage, PU')

set(gca,'XTick',10:10:k_h)

set(gca,'XTickLabel',{'1','2','3','4','5',
'6','7','8','9','10','11','12','13','14','15','16','17','18','19','20','21','22','23','24','25'})
```

Appendix E – Relationship between SCR and Changes of Voltages at PCCs

The IEEE has included the concept of allocating harmonic currents relative to the *Short Circuit Ratio* (*SCR*), which is described in equations below, at a PCC.

$$SCR_{PCC} = \frac{S_{SC}}{P_n} \tag{E.1}$$

Short Circuit Power (S_{SC}) can be approximated from the Thevenin equivalent network modelled as illustrated in Figure E.1 below:

$$S_{SC} = \frac{U_{PCC}^2}{Z_{th}} \tag{E.2}$$

$$SCR_{PCC} = \frac{S_{SC}}{P_n} = \frac{U_{PCC}^2}{P_n} \times \frac{1}{Z_{th}} \cong \frac{I_{SC}}{I_{Load}} \tag{E.3}$$

P_n: *Nominal Power of a Generator* being considered for installation in the network.

S_{SC}: *Short Circuit Power* (Full Power of a 3 Phase Short Circuit to Ground) as seen at the PCC.

Load current (I_L) can be considered as an equivalent generator current, i.e. generator currents that supply load. The IEEE standard allows higher harmonic current allocations to loads connected to PCCs with a higher *SCR* (I_{SC}/I_{Load}) ratio. This is presumably based on the principles that fundamental frequency voltages are more stable at PCCs with higher *SCR*. At the fundamental frequency, another terminology that is often being used to colloquially describe network PCCs that highly susceptible to voltage fluctuation is so-called "*Weak Network Buses*", i.e. busbars with low fault currents (high Diagonal impedance or high Thevenin impedance). The reverse terminology is also being used to refer to PCCs with low Thevenin impedance, i.e. "*Strong Network Buses*", and high fault currents. In physic terms, what it really means is that busbars with low Thevenin impedance represent low impedance paths for currents to flow through. Therefore, it reduces the magnitude of the voltage drop across the network equivalent impedance hence resulting in fewer voltages fluctuations at PCCs. However, this phenomenon occurs at the fundamental frequency only and may not be true at harmonic frequencies because the Thevenin equivalent impedance can change considerably at harmonic frequencies. This raises a question, what is the relationship between *SCR* at PCCs and harmonic currents, voltages and impedances at harmonic frequencies?. An example is provided below to illustrate the effects of short circuit currents (or SCRs) on voltages and currents at the fundamental frequency and harmonic frequencies.

E.1 Example – Relationship between SCR and Changes of Voltages at PCCs

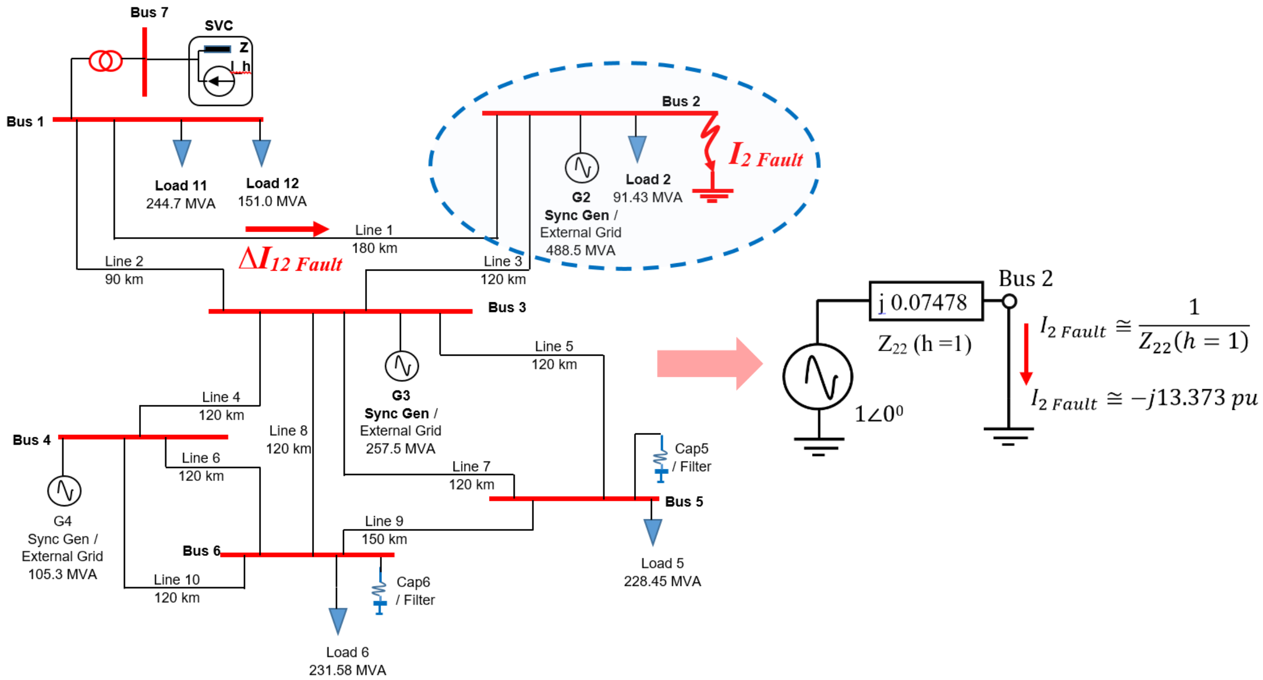


Figure E. 1 – Three Phase Short Circuit Currents at Bus 2 and Thevenin Equivalent Impedance ($1/Z_{22}$)

E.1.1 At Fundamental Frequency

The change in voltages, at the fundamental frequency, due to the three-phase short circuit current at Bus 2 can be defined from the Matrix below:

$$\begin{bmatrix} \Delta V_1 \\ \Delta V_2 \\ \Delta V_3 \\ \Delta V_4 \\ \Delta V_5 \\ \Delta V_6 \\ \Delta V_7 \end{bmatrix} = \begin{bmatrix} Z_{1,1} & \boxed{Z_{1,2}} & Z_{1,3} & Z_{1,4} & Z_{1,5} & Z_{1,6} & Z_{1,7} \\ Z_{2,1} & Z_{2,2} & Z_{2,3} & Z_{2,4} & Z_{2,5} & Z_{2,6} & Z_{2,7} \\ Z_{3,1} & Z_{3,2} & Z_{3,3} & Z_{3,4} & Z_{3,5} & Z_{3,6} & Z_{3,7} \\ Z_{4,1} & Z_{4,2} & Z_{4,3} & Z_{4,4} & Z_{4,5} & Z_{4,6} & Z_{4,7} \\ Z_{5,1} & Z_{5,2} & Z_{5,3} & Z_{5,4} & Z_{5,5} & Z_{5,6} & Z_{5,7} \\ Z_{6,1} & Z_{6,2} & Z_{6,3} & Z_{6,4} & Z_{6,5} & Z_{6,6} & Z_{6,7} \\ Z_{7,1} & Z_{7,2} & Z_{7,3} & Z_{7,4} & Z_{7,5} & Z_{7,6} & Z_{7,7} \end{bmatrix} . \begin{bmatrix} 0 \\ I_{2\ Fault} \\ 0 \\ 0 \\ 0 \\ 0 \\ 0 \end{bmatrix} \tag{E.4}$$

Notes: $I_{2\ Fault}$ current flows from Bus 2 to ground.

The current flow from Bus 1 to Bus 2, as shown in Figure E.15 above, can be calculated from:

$$\Delta I_{12\ Fault} = \frac{\Delta V_1 - \Delta V_2}{Z_{1,2}} \tag{E.5}$$

The voltages during the fault are the initial voltages minus the changes in the voltages. Assuming all bus voltages are at 1 $\angle 0^0$ (hence all initial currents are 0), the voltages at bus 1, 2 and 3 during fault can be calculated as follows:

$$\begin{bmatrix} \Delta V_1 \\ \Delta V_2 \\ \Delta V_3 \\ \Delta V_4 \\ \Delta V_5 \\ \Delta V_6 \\ \Delta V_7 \end{bmatrix} = j \begin{bmatrix} 0.0502 & 0.0150 & 0.0180 & 0.0083 & 0.0162 & 0.0106 & 0.0176 \\ 0.0150 & 0.0748 & 0.0208 & 0.0096 & 0.0187 & 0.0122 & 0.0053 \\ 0.0180 & 0.0208 & 0.0662 & 0.0307 & 0.0596 & 0.0389 & 0.0063 \\ 0.0083 & 0.0096 & 0.0307 & 0.0823 & 0.0370 & 0.0476 & 0.0029 \\ 0.0162 & 0.0187 & 0.0596 & 0.0370 & 0.1419 & 0.0575 & 0.0057 \\ 0.0106 & 0.0122 & 0.0389 & 0.0476 & 0.0575 & 0.0936 & 0.0037 \\ 0.0176 & 0.0053 & 0.0063 & 0.0029 & 0.0057 & 0.0037 & 0.0331 \end{bmatrix} . \begin{bmatrix} 0 \\ (-j13.373) \\ 0 \\ 0 \\ 0 \\ 0 \\ 0 \end{bmatrix}$$

$$\begin{bmatrix} 0.2011 \\ 1.000 \\ 0.2779 \\ 0.1287 \\ 0.2500 \\ 0.1635 \\ 0.0705 \end{bmatrix} = j \begin{bmatrix} 0.0502 & 0.0150 & 0.0180 & 0.0083 & 0.0162 & 0.0106 & 0.0176 \\ 0.0150 & 0.0748 & 0.0208 & 0.0096 & 0.0187 & 0.0122 & 0.0053 \\ 0.0180 & 0.0208 & 0.0662 & 0.0307 & 0.0596 & 0.0389 & 0.0063 \\ 0.0083 & 0.0096 & 0.0307 & 0.0823 & 0.0370 & 0.0476 & 0.0029 \\ 0.0162 & 0.0187 & 0.0596 & 0.0370 & 0.1419 & 0.0575 & 0.0057 \\ 0.0106 & 0.0122 & 0.0389 & 0.0476 & 0.0575 & 0.0936 & 0.0037 \\ 0.0176 & 0.0053 & 0.0063 & 0.0029 & 0.0057 & 0.0037 & 0.0331 \end{bmatrix} . \begin{bmatrix} 0 \\ (-j13.373) \\ 0 \\ 0 \\ 0 \\ 0 \\ 0 \end{bmatrix}$$

$V_{1\ Fault} = V_{1\ Initial} - \Delta V_1 = 1\angle 0^0 - 0.2011 = 0.7989$

$V_{2\ Fault} = V_{1\ Initial} - \Delta V_2 = 1\angle 0^0 - 1.0000 = 0.0000$

$V_{3\ Fault} = V_{1\ Initial} - \Delta V_3 = 1\angle 0^0 - 0.1287 = 0.7221$

E.1.2 At Harmonic Frequencies

It has been found that changes of Thevenin impedance with frequencies are not linear as discussed in Chapter 4 and shown, as admittance, e.g. $1/Z_{22}(h)$, in Figure 6.2, 6.3 and 6.4 above. It showed that at harmonic frequencies the Thevenin impedance varies in a non-linear manner across the harmonic spectrum and its profiles are different from one bus to another. Effectively, its characteristics vary in different forms at different harmonic frequencies. It has been observed that while *SCR* is directly linked to the stability effects on frequency and voltage control at the fundamental frequency, its relationship with currents and voltages at harmonic frequencies can be very complex and unpredictable.

This example clearly illustrated that the variation of fundamental voltages in the system is directly linked to the *Short Circuit Levels* at PCCs. However, the entire process does not have any reference to, or impacts on, harmonic currents and voltages. This example showed that is no clear correlation between *Short Circuit Ratio* (I_{SC}/I_L) at the fundamental frequency and voltages and currents at harmonic frequencies because network impedances can vary significantly in an unpredictable manner between fundamental and harmonic frequencies. Therefore, the principles of allocating harmonic currents, relative fundamental *Short Circuit Ratio* (I_{SC}/I_L) as recommended by the IEEE standard, can be questionable. It could even result in unintended consequences at harmonic frequencies due to unpredictable changes of complex impedances at harmonic frequencies.

Based on this example, the *Short Circuit Ratio* (I_{SC}/I_L) can be expressed at the fundamental frequency as:

$$\frac{I_{SC}(h=1)}{I_L(h=1)} \quad \rightarrow \quad \frac{1}{Z_{i,i}(h=1) \times I_L(h=1)} \tag{E.6}$$

Equation (E.6) would appear at harmonic frequencies as:

$$\frac{1}{Z_{i,i}(h>1) \times I_L(h>1)} \tag{E.7}$$

The effects of *Short Circuit Ratio* (I_{SC}/I_L) on fundamental frequency voltages can be very different to harmonic voltages depending on the composition of network elements.

$$\left.\begin{array}{c} Z_{i,i}(h=1) \neq Z_{i,i}(h>1) \\ I_L(h=1) \neq I_L(h>1) \end{array}\right] \rightarrow \frac{I_{SC}(h=1)}{I_L(h=1)} \neq \frac{I_{SC}(h>1)}{I_L(h>1)} \tag{E.8}$$

Appendix F – A Case Study – Allocations for Renewable Generators

Table F.1 – Generators G8, G9 and G10 – Detailed Information

PCC	**Bus 8**	**Bus 9**	**Bus 10**
Plant Name	**G8**	**G9**	**G10**
Plant Type	**Solar**	**Solar**	**Wind**
Generator Output Capacity (MVA)	**320**	**525**	**125**
***Total New Load S_i* (= 5% of Generator Output Capacity (MVA)**	**16.00**	**26.25**	**6.25**
Total Supply Capacity *(S_{tS})* (MVA, According to (7.3))	**16.00**	**26.25**	**6.25**
Total Existing Loads	0	0	0
Total Export Power (MVA) at PCC	320	525	125
Short Circuit Power (MVA) at PCC	3.647	4.860	3.412
Generator Active Power (MW, P_{Gen})	314.42	515.85	121.35
Power Factor	0.983	0.983	0.971
Short Circuit Ratio (SCR @ fundamental frequency) at PCCs	1.160	0.942	2.812

Table F.2 – Comparison of harmonic allocation to renewable generators G8, G9 and G10 Based on Generators' MVA Rating and Station Load

h	Option One			Option Two			Planning Level (%)
	Very Small Allocation Based on New Allocation Method (i.e. Relative to Generator's Station Load)			**Over-Allocation Based on Generators' MVA Output**			
	G8	G9	G10	G8	G9	G10	
2	0.0022%	0.0037%	0.0008%	0.0448%	0.0738%	0.0168%	0.00%
3	0.0032%	0.0053%	0.0012%	0.0643%	0.1059%	0.0241%	1.40%
4	0.0013%	0.0021%	0.0005%	0.0255%	0.0420%	0.0096%	2.00%
5	0.0089%	0.0127%	0.0044%	0.1782%	0.2546%	0.0884%	0.80%
6	0.0017%	0.0025%	0.0009%	0.0344%	0.0491%	0.0171%	2.00%
7	0.0081%	0.0116%	0.0040%	0.1624%	0.2320%	0.0806%	0.40%
8	0.0015%	0.0021%	0.0007%	0.0298%	0.0426%	0.0148%	2.00%
9	0.0033%	0.0047%	0.0016%	0.0653%	0.0933%	0.0324%	0.40%
10	0.0009%	0.0014%	0.0005%	0.0189%	0.0270%	0.0094%	1.00%
11	0.0073%	0.0094%	0.0045%	0.1470%	0.1887%	0.0900%	0.35%
12	0.0012%	0.0016%	0.0008%	0.0249%	0.0320%	0.0153%	1.50%
13	0.0047%	0.0060%	0.0028%	0.0930%	0.1194%	0.0570%	0.32%
14	0.0008%	0.0010%	0.0005%	0.0150%	0.0193%	0.0092%	1.50%
15	0.0009%	0.0011%	0.0005%	0.0176%	0.0226%	0.0108%	0.30%
16	0.0011%	0.0014%	0.0007%	0.0213%	0.0274%	0.0131%	0.30%
17	0.0048%	0.0062%	0.0029%	0.0959%	0.1231%	0.0587%	0.28%
18	0.0015%	0.0019%	0.0009%	0.0303%	0.0389%	0.0185%	1.20%
19	0.0053%	0.0068%	0.0032%	0.1060%	0.1360%	0.0649%	0.27%
20	0.0010%	0.0013%	0.0006%	0.0207%	0.0266%	0.0127%	1.07%
21	0.0006%	0.0008%	0.0004%	0.0127%	0.0163%	0.0078%	0.26%
22	0.0005%	0.0007%	0.0003%	0.0107%	0.0137%	0.0065%	0.20%
23	0.0011%	0.0015%	0.0007%	0.0227%	0.0291%	0.0139%	0.25%
24	0.0002%	0.0002%	0.0001%	0.0034%	0.0044%	0.0021%	0.89%
25	0.0010%	0.0013%	0.0006%	0.0199%	0.0256%	0.0122%	0.24%

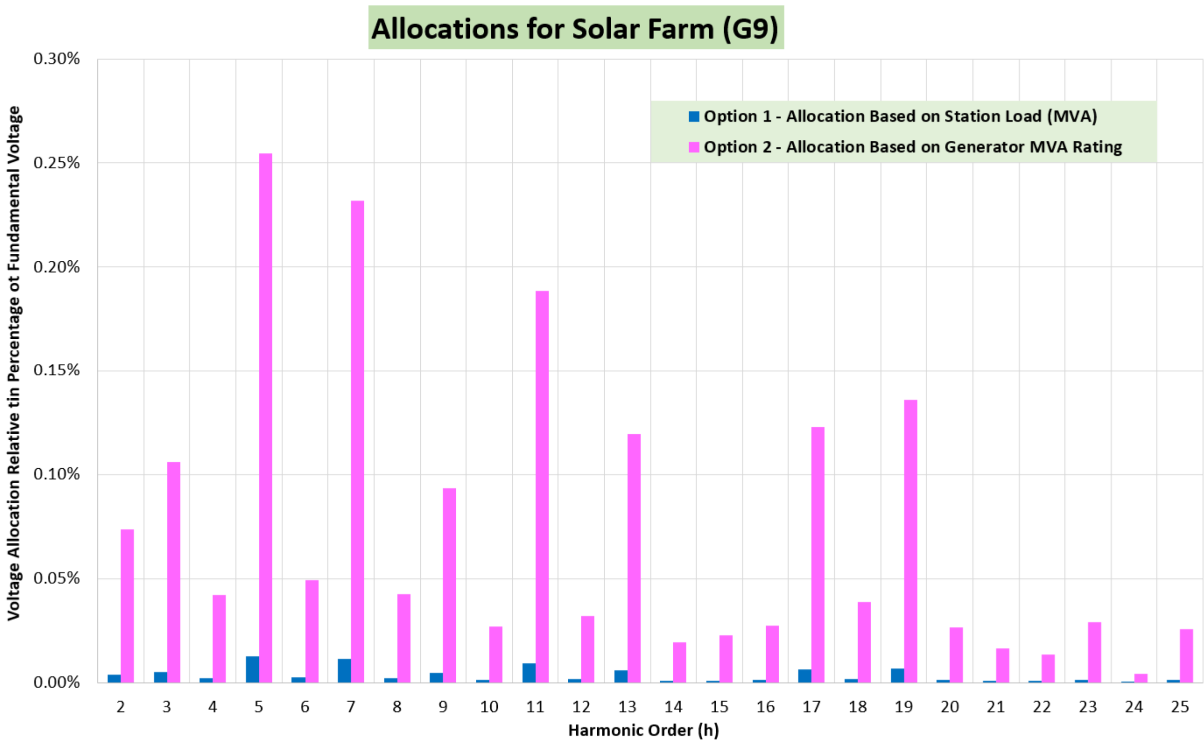


Figure F.1 – Allocation for Solar Farm (G9)

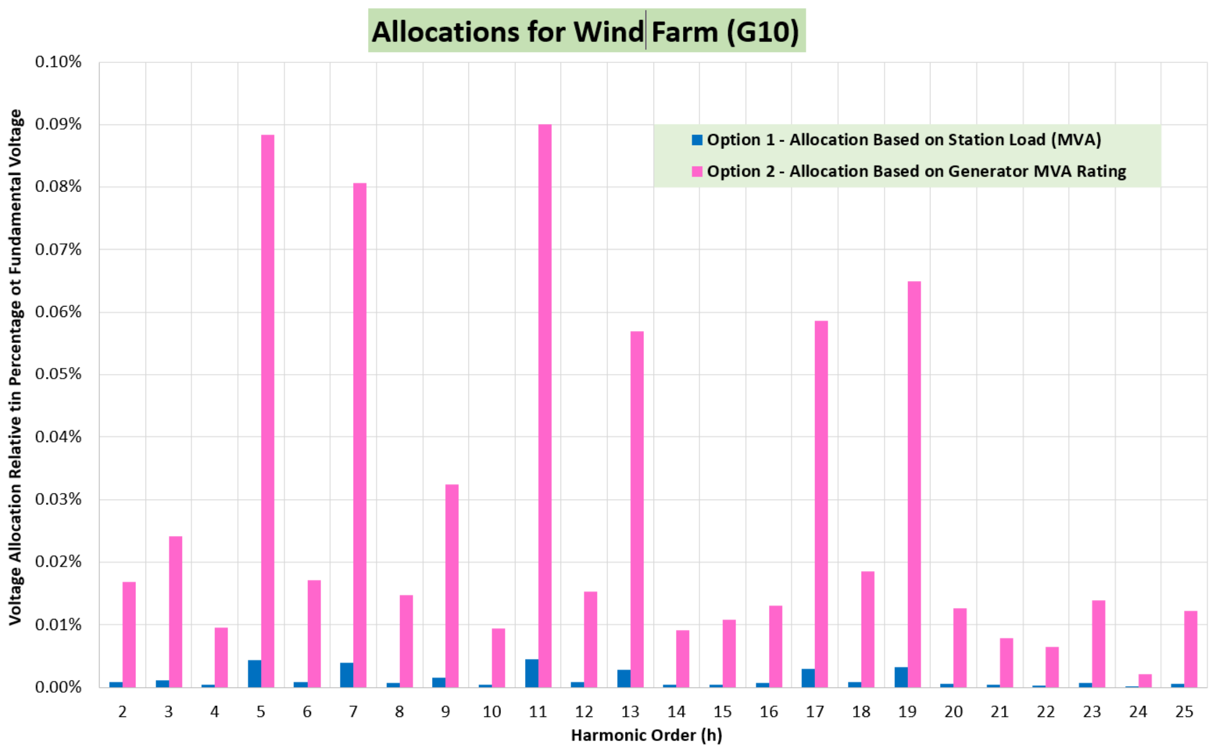


Figure F.2 – Allocation for Solar Farm (G10)

Appendix G – Optimised Network Scenario Data

Table G.1 – Optimised Network Scenario for Load 11, requires high 5^th^, 7^th^ and 11^th^ Harmonic Profile

Load 11 244.73 MVA	E_{U_5} (%)	Network Scenario Based on E_{U_5} (%)	E_{U_7} (%)	Network Scenario Based on E_{U_7} (%)	E_{U_11} (%)	Network Scenario Based on E_{U_11} (%)	F_{Max_11}	Network Scenario Based on Load 11 F_{Max}
Planning (%)	2.00		2.00		1.50			
Q_{F_11} (%)		1.00		1.00		26.20		
$Q_{F\_FMax\_11}$ (%)								2.00
	1.416	1	1.346		0.391		2.723	
	1.396		1.352		0.536	2	2.726	
	1.419	**3**	**1.419**	3	0.396	3	2.903	3
	1.419	4	1.419	4	0.398	4	2.842	
	1.419	5	1.379		0.394		2.703	
	1.418	6	1.400		0.392		2.536	
	1.419	7	1.409	7	0.382		2.804	
	1.418	8	1.376		0.393		2.763	
	1.419	9	1.409	9	0.387		2.777	
	1.419	10	1.404		0.394		2.662	
	1.419	11	1.405	11	0.396	11	2.728	
	1.419	12	1.378		0.393		2.768	
	1.209		0.713		0.397	13	2.544	
	1.414	14	1.391		0.391		2.732	
	1.408	15	1.177		0.393		2.673	
	1.400		1.012		0.395		2.688	
	1.407	17	0.855		0.393		2.571	
	1.419	18	1.313		0.387		2.396	
	1.419	19	1.418	19	0.392		2.959	19
	1.419	20	0.994		0.399	20	2.862	
Load 11 OOS	N/A		N/A		N/A		N/A	
Load 12 OOS	N/A		N/A		N/A		N/A	

Q_{F_11}(%): Harmonic Profile Tolerance for load 11.
Q_{F_12}(%): Harmonic Profile Tolerance for load 12.
$Q_{F\_FMAX\_11}$(%): Tolerance of F_{Max} (Maximum RMS Normalised Allocation Factor) for Load 11.
$Q_{F\_FMAX\_11}$(%): Tolerance of F_{Max} (Maximum RMS Normalised Allocation Factor) for Load 12.

Table G.2 – Optimised Network Scenario for Load 11, requires high 21st, 23rd and 25th Harmonic Profile

Load 11 244.73 MVA	E_{U_21} (%)	Network Scenario Based on E_{U_21} (%)	E_{U_23} (%)	Network Scenario Based on E_{U_23} (%)	E_{U_25} (%)	Network Scenario Based on E_{U_25} (%)	F_{Max_11}	Network Scenario Based on Load 11 F_{Max}
Planning (%)	0.20		0.89		0.82			
Q_{F_11} (%)		15.95		5.00		0.01		
$Q_{F\_FMax\_11}$ (%)								3.30
	0.135	1	0.456		0.642	1	2.723	
	0.135	2	0.457		0.642	2	2.726	
	0.157	3	0.454		0.642	3	2.903	3
	0.156	4	0.469		0.642	4	2.842	
	0.157	5	0.428		0.642	5	2.703	
	0.134	6	0.416		0.640		2.536	
	0.135	7	0.448		0.642	7	2.804	
	0.134	8	0.448		0.642	8	2.763	
	0.134	9	0.683	9	0.368		2.777	
	0.126		0.612		0.589		2.662	
	0.125		0.698	11	0.642	11	2.728	
	0.134	12	0.448		0.642	12	2.768	
	0.134	13	0.423		0.642	13	2.544	
	0.134	14	0.456		0.642	14	2.732	
	0.130		0.446		0.642	15	2.673	
	0.135	16	0.451		0.642	16	2.688	
	0.134	17	0.452		0.642	17	2.571	
	0.031		0.449		0.642	18	2.396	
	0.139	19	0.509		0.642	19	2.959	19
	0.132	20	0.663	20	0.642	20	2.862	20
Load 11 OOS	N/A		N/A		N/A		N/A	
Load 12 OOS	N/A		N/A		N/A		N/A	

Table G.3 – Optimised Network Scenario for Load 12, requires high 5th, 7th and 11th Harmonic Profile

Load 12 151 MVA	E_{U_5} (%)	Network Scenario Based on E_{U_5} (%)	E_{U_7} (%)	Network Scenario Based on E_{U_7} (%)	E_{U_11} (%)	Network Scenario Based on E_{U_11} (%)	F_{Max_12}	Network Scenario Based on Load 12 F_{Max}
Planning (%)	2.00		2.00		1.50			
Q_{F_12} (%)		1.00		1.00		26.20		
$Q_{F\_FMax\_12}$ (%)								1.50
	1.003	1	0.954		0.307		2.048	
	0.989		0.958		0.421	2	2.053	
	1.005	**3**	**1.005**	3	0.311	3	2.191	3
	1.005	4	1.005	4	0.312	4	2.134	
	1.005	5	0.977		0.309		2.031	
	1.004	6	0.992		0.308		1.892	
	1.005	7	0.998	7	0.300		2.108	
	1.005	8	0.975		0.308		2.081	
	1.005	9	0.998	9	0.304		2.080	
	1.005	10	0.995		0.310		1.994	
	1.005	11	0.995	11	0.311	11	2.052	
	1.005	12	0.976		0.309		2.084	
	0.856		0.505		0.312	13	1.920	
	1.001	14	0.985		0.308		2.054	
	0.997	15	0.834		0.308		2.011	
	0.992		0.717		0.310		2.037	
	0.996	17	0.606		0.309		1.948	
	1.005	18	0.930		0.304		1.779	
	1.005	19	1.004	19	0.308		2.224	19
	1.005	20	0.704		0.313	20	2.161	
Load 11 OOS	N/A		N/A		N/A		N/A	
Load 12 OOS	N/A		N/A		N/A		N/A	

Table G.4 – Optimised Network Scenario for Load 12, with high 21st, 23rd and 25th Harmonic Profile

Load 12 151 MVA	E_{U_21} (%)	Network Scenario Based on E_{U_21} (%)	E_{U_23} (%)	Network Scenario Based on E_{U_23} (%)	E_{U_25} (%)	Network Scenario Based on E_{U_25} (%)	F_{Max_12}	Network Scenario Based on Load 12 F_{Max}
Planning (%)	0.20		0.89		0.82			
Q_{F_12} (%)		15.95		5.00		1.00		
$Q_{F\_FMax\_12}$ (%)								2.90
	0.106	1	0.358		0.504	1	2.048	
	0.106	2	0.359		0.504	2	2.053	
	0.124	3	0.357		0.504	3	2.191	3
	0.123	4	0.369		0.504	4	2.134	
	0.124	5	0.337		0.504	5	2.031	
	0.105	6	0.327		0.503	6	1.892	
	0.106	7	0.352		0.504	7	2.108	
	0.105	8	0.352		0.504	8	2.081	
	0.105	9	0.537	9	0.289		2.080	
	0.099		0.480		0.462		1.994	
	0.098		0.548	11	0.504	11	2.052	
	0.105	12	0.352		0.504	12	2.084	
	0.105	13	0.332		0.504	13	1.920	
	0.105	14	0.358		0.504	14	2.054	
	0.102		0.350		0.504	15	2.011	
	0.106	16	0.354		0.504	16	2.037	
	0.105	17	0.355		0.504	17	1.948	
	0.024		0.353		0.504	18	1.779	
	0.109	19	0.400		0.504	19	2.224	19
	0.104	20	0.521	20	0.504	20	2.161	20
Load 11 OOS	N/A		N/A		N/A		N/A	
Load 12 OOS	N/A		N/A		N/A		N/A	

Table G.5 – Optimised Network Scenario for Load 11, with high 5th, 7th and 11th, and Load 12 with high 21st, 23rd and 25th Harmonic Profile – Option 1

	Load 11 (244.73 MVA)								Load 12 (151 MVA)							
	E_{U_5} (%)	Network Scenario Based on E_{U_5} (%)	E_{U_7} (%)	Network Scenario Based on E_{U_7} (%)	E_{U_11} (%)	Network Scenario Based on E_{U_11} (%)	F_{Max_11}	Scenario Based on Load 11 F_{Max}	E_{U_21} (%)	Network Scenario Based on E_{U_21} (%)	E_{U_23} (%)	Network Scenario Based on E_{U_23} (%)	E_{U_25} (%)	Network Scenario Based on E_{U_25} (%)	F_{Max_12}	Scenario Based on Load 12 F_{Max}
Planning (%)	2.00		2.00		1.50				0.20		0.89		0.82			
Q_{F_11} (%)	1.00		29.98		25.54											
Q_{F_12} (%)									15.92		4.98		1.00			
$Q_{F\_FMax\_11}$(%)								3.27								
$Q_{F\_FMax\_12}$ (%)																2.81
	1.416	1	1.346	1	0.391		2.723		0.106	1	0.358		0.504	1	2.048	
	1.396		1.352	2	0.536	2	2.726		0.106	2	0.359		0.504	2	2.053	
	1.419	3	1.419	3	0.396	3	2.903	3	0.124	3	0.357		0.504	3	2.191	3
	1.419	4	1.419	4	0.398	4	2.842		0.123	4	0.369		0.504	4	2.134	
	1.419	5	1.379	5	0.394		2.703		0.124	5	0.337		0.504	5	2.031	
	1.418	6	1.400	6	0.392		2.536		0.105	6	0.327		0.503	6	1.892	
	1.419	7	1.409	7	0.382		2.804		0.106	7	0.352		0.504	7	2.108	
	1.418	8	1.376	8	0.393		2.763		0.105	8	0.352		0.504	8	2.081	
	1.419	9	1.409	9	0.387		2.777		0.105	9	0.537	9	0.289		2.080	
	1.419	10	1.404	10	0.394		2.662		0.099		0.480		0.462		1.994	
	1.419	11	1.405	11	0.396	11	2.728		0.098		0.548	11	0.504	11	2.052	

	1.419	12	1.378	12	0.393		2.768		0.105	12	0.352		0.504	12	2.084	
	1.209		0.713		0.397	13	2.544		0.105	13	0.332		0.504	13	1.920	
	1.414	14	1.391	14	0.391		2.732		0.105	14	0.358		0.504	14	2.054	
	1.408	15	1.177	15	0.393		2.673		0.102		0.350		0.504	15	2.011	
	1.400		1.012	16	0.395		2.688		0.106	16	0.354		0.504	16	2.037	
	1.407	17	0.855		0.393		2.571		0.105	17	0.355		0.504	17	1.948	
	1.419	18	1.313	18	0.387		2.396		0.024		0.353		0.504	18	1.779	
	1.419	19	1.418	19	0.392		2.959	19	0.109	19	0.400		0.504	19	2.224	19
	1.419	20	0.994	20	0.399	20	2.862	20	0.104	20	0.521	20	0.504	20	2.161	20
Load 11 OOS	N/A		N/A		N/A		N/A		N/A		N/A		N/A		N/A	
Load 12 OOS	N/A		N/A		N/A		N/A		N/A		N/A		N/A		N/A	

Table G.6 – Optimised Network Scenario for Load 11, with high 5th, 7th and 11th, and Load 12 with high 21st, 23rd and 25th Harmonic Profile – Option 2

	Load 11 (244.73 MVA)								Load 12 (151 MVA)							
	E_{U_5} (%)	Network Scenario Based on E_{U_5} (%)	E_{U_7} (%)	Network Scenario Based on E_{U_7} (%)	E_{U_11} (%)	Network Scenario Based on E_{U_11} (%)	F_{Max_11}	Scenario Based on Load 11 F_{Max}	E_{U_21} (%)	Network Scenario Based on E_{U_21} (%)	E_{U_23} (%)	Network Scenario Based on E_{U_23} (%)	E_{U_25} (%)	Network Scenario Based on E_{U_25} (%)	F_{Max_12}	Scenario Based on Load 12 F_{Max}
Planning (%)	2.00		2.00		1.50				0.20		0.89		0.82			
Q_{F_11} (%)	1.00		1.00		26.20											
Q_{F_12} (%)									1.00		34.95		1.00			
$Q_{F\_FMax\_11}$(%)								1.90								
$Q_{F\_FMax\_12}$ (%)																1.50
	1.416	1	1.346		0.391		2.723		0.106		0.358	1	0.504	1	2.048	
	1.396		1.352		0.536	2	2.726		0.106		0.359	2	0.504	2	2.053	
	1.419	**3**	**1.419**	3	0.396	3	2.903	3	0.124	3	0.357	3	0.504	3	2.191	3
	1.419	4	1.419	4	0.398	4	2.842		0.123	4	0.369	4	0.504	4	2.134	
	1.419	5	1.379		0.394		2.703		0.124	5	0.337		0.504	5	2.031	
	1.418	6	1.400		0.392		2.536		0.105		0.327		0.503	6	1.892	
	1.419	7	1.409	7	0.382		2.804		0.106		0.352		0.504	7	2.108	
	1.418	8	1.376		0.393		2.763		0.105		0.352		0.504	8	2.081	
	1.419	9	1.409	9	0.387		2.777		0.105		0.537	9	0.289		2.080	
	1.419	10	1.404		0.394		2.662		0.099		0.480	10	0.462		1.994	
	1.419	11	1.405	11	0.396	11	2.728		0.098		0.548	11	0.504	11	2.052	

	1.419	12	1.378		0.393		2.768		0.105		0.352		0.504	12	2.084	
	1.209		0.713		0.397	13	2.544		0.105		0.332		0.504	13	1.920	
	1.414	14	1.391		0.391		2.732		0.105		0.358	14	0.504	14	2.054	
	1.408	15	1.177		0.393		2.673		0.102		0.350		0.504	15	2.011	
	1.400		1.012		0.395		2.688		0.106		0.354		0.504	16	2.037	
	1.407	17	0.855		0.393		2.571		0.105		0.355		0.504	17	1.948	
	1.419	18	1.313		0.387		2.396		0.024		0.353		0.504	18	1.779	
	1.419	19	1.418	19	0.392		2.959	19	0.109		0.400	19	0.504	19	2.224	19
	1.419	20	0.994		0.399	20	2.862		0.104		0.521	20	0.504	20	2.161	
Load 11 OOS	N/A		N/A		N/A		N/A		N/A		N/A		N/A		N/A	
Load 12 OOS	N/A		N/A		N/A		N/A		N/A		N/A		N/A		N/A	

Table G.7 – Optimised Network Scenario for Load 12, with high 5th, 7th and 11th, and Load 11 with high 21st, 23rd and 25th Harmonic Profile – Option 1

	Load 12 (151 MVA)								Load 11 (244.73 MVA)							
	E_{U_5} (%)	Network Scenario Based on E_{U_5} (%)	E_{U_7} (%)	Network Scenario Based on E_{U_7} (%)	E_{U_11} (%)	Network Scenario Based on E_{U_11} (%)	F_{Max_12}	Scenario Based on Load 12 F_{Max}	E_{U_21} (%)	Network Scenario Based on E_{U_21} (%)	E_{U_23} (%)	Network Scenario Based on E_{U_23} (%)	E_{U_25} (%)	Network Scenario Based on E_{U_25} (%)	F_{Max_11}	Scenario Based on Load 11 F_{Max}
Planning (%)	2.00		2.00		1.50				0.20		0.89		0.82			
Q_{F_11} (%)									0.01		34.91		0.01			
Q_{F_12} (%)	0.01		0.01		26.16											
$Q_{F\_FMax\_11}$(%)																1.88
$Q_{F\_FMax\_12}$ (%)								1.48								
	1.003		0.954		0.307		2.048		0.135		0.456	1	0.642	1	2.723	
	0.989		0.958		0.421	2	2.053		0.135		0.457	2	0.642	2	2.726	
	1.005	**3**	**1.005**	3	0.311	3	2.191	3	0.157	3	0.454	3	0.642	3	2.903	3
	1.005	4	1.005	4	0.312	4	2.134		0.156		0.469	4	0.642	4	2.842	
	1.005	5	0.977		0.309		2.031		0.157	5	0.428		0.642	5	2.703	
	1.004		0.992		0.308		1.892		0.134		0.416		0.640		2.536	
	1.005	7	0.998		0.300		2.108		0.135		0.448		0.642	7	2.804	
	1.005		0.975		0.308		2.081		0.134		0.448		0.642	8	2.763	
	1.005	9	0.998		0.304		2.080		0.134		0.683	9	0.368		2.777	
	1.005	10	0.995		0.310		1.994		0.126		0.612	10	0.589		2.662	
	1.005	11	0.995		0.311	11	2.052		0.125		0.698	11	0.642	11	2.728	

	1.005		0.976		0.309		2.084		0.134		0.448		0.642	12	2.768	
	0.856		0.505		0.312	13	1.920		0.134		0.423		0.642	13	2.544	
	1.001		0.985		0.308		2.054		0.134		0.456	14	0.642	14	2.732	
	0.997		0.834		0.308		2.011		0.130		0.446		0.642	15	2.673	
	0.992		0.717		0.310		2.037		0.135		0.451		0.642	16	2.688	
	0.996		0.606		0.309		1.948		0.134		0.452		0.642	17	2.571	
	1.005	18	0.930		0.304		1.779		0.031		0.449		0.642	18	2.396	
	1.005	19	1.004		0.308		2.224	19	0.139		0.509	19	0.642	19	2.959	19
	1.005	20	0.704		0.313	20	2.161		0.132		0.663	20	0.642	20	2.862	
Load 11 OOS	N/A		N/A		N/A		N/A		N/A		N/A		N/A		N/A	
Load 12 OOS	N/A		N/A		N/A		N/A		N/A		N/A		N/A		N/A	

Table G.8 – Optimised Network Scenario for Load 12, with high 5^th^, 7^th^ and 11^th^, and Load 11 with high 21^st^, 23^rd^ and 25^th^ Harmonic Profile – Option 2

	Load 12 (151 MVA)								Load 11 (244.73 MVA)							
	E_{U_5} (%)	Network Scenario Based on E_{U_5} (%)	E_{U_7} (%)	Network Scenario Based on E_{U_7} (%)	E_{U_11} (%)	Network Scenario Based on E_{U_11} (%)	F_{Max_12}	Scenario Based on Load 12 F_{Max}	E_{U_21} (%)	Network Scenario Based on E_{U_21} (%)	E_{U_23} (%)	Network Scenario Based on E_{U_23} (%)	E_{U_25} (%)	Network Scenario Based on E_{U_25} (%)	F_{Max_11}	Scenario Based on Load 11 F_{Max}
Planning (%)	2.00		2.00		1.50				0.20		0.89		0.82			
Q_{F_11} (%)									11.78		27.05		0.01			
Q_{F_12} (%)	0.01		0.06		26.82											
$Q_{F\_FMax\_11}$(%)																0.01
$Q_{F\_FMax\_12}$ (%)								0.01								
	1.003		0.954		0.307		2.048		0.135		0.456		0.642	1	2.723	
	0.989		0.958		0.421	2	2.053		0.135		0.457		0.642	2	2.726	
	1.005	3	1.005	3	0.311	3	2.191		0.157	3	0.454		0.642	3	2.903	
	1.005	4	1.005	4	0.312	4	2.134		0.156	4	0.469		0.642	4	2.842	
	1.005	5	0.977		0.309	5	2.031		0.157	5	0.428		0.642	5	2.703	
	1.004		0.992		0.308	6	1.892		0.134		0.416		0.640		2.536	
	1.005	7	0.998		0.300		2.108		0.135		0.448		0.642	7	2.804	
	1.005		0.975		0.308	8	2.081		0.134		0.448		0.642	8	2.763	
	1.005	9	0.998		0.304		2.080		0.134		0.683	9	0.368		2.777	
	1.005	10	0.995		0.310	10	1.994		0.126		0.612	10	0.589		2.662	
	1.005	11	0.995		0.311	11	2.052		0.125		0.698	11	0.642	11	2.728	

	1.005		0.976		0.309	12	2.084		0.134		0.448		0.642	12	2.768	
	0.856		0.505		0.312	13	1.920		0.134		0.423		0.642	13	2.544	
	1.001		0.985		0.308		2.054		0.134		0.456		0.642	14	2.732	
	0.997		0.834		0.308	15	2.011		0.130		0.446		0.642	15	2.673	
	0.992		0.717		0.310	16	2.037		0.135		0.451		0.642	16	2.688	
	0.996		0.606		0.309	17	1.948		0.134		0.452		0.642	17	2.571	
	1.005	18	0.930		0.304		1.779		0.031		0.449		0.642	18	2.396	
	1.005	**19**	**1.004**	19	**0.308**	**19**	**2.224**	**19**	**0.139**	**19**	**0.509**	**19**	**0.642**	**19**	**2.959**	**19**
	1.005	20	0.704		0.313	20	2.161		0.132		0.663	20	0.642	20	2.862	
Load 11 OOS	N/A		N/A		N/A		N/A		N/A		N/A		N/A		N/A	
Load 12 OOS	N/A		N/A		N/A		N/A		N/A		N/A		N/A		N/A	