

Evaluating, Planning, and Ranking of Multi-Infeed HVDC Systems Using Unified Control Performance Indices

by

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Abstract

Modernizing multi-infeed HVDC corridors increasingly involves replacing aging line-commutated converters with voltage-sourced converters to improve controllability and fault resilience. However, conventional planning indices remain largely static and are often treated as separate metrics, making it difficult to consistently rank modernization options across a defined contingency set. This thesis proposes a streamlined screening method based on Control Performance Indices (CPIs) that summarizes post-fault recovery by penalizing deviation magnitude and persistence. The approach evaluates voltage, frequency, and DC power trajectories and organizes the results into a station-by-contingency CPI matrix. Structured aggregation produces an event-level index for ranking contingency severity, a station-level index for identifying vulnerable terminals, and system-level metrics for comparing alternatives through a reference benchmark. The framework is validated on a three-bipole Manitoba Hydro modernization scenario and yields consistent rankings across converter topologies, ratings, and control modes; among the cases studied, a higher-rated VSC–VSC configuration with inverter AC-voltage control delivers the most robust post-fault performance under the evaluated fault set. The method is further extended to low-voltage ride-through assessment by mapping fault duration and retained voltage to a capability surface and is implemented as a Python-based automation workflow to ensure repeatable, auditable planning studies.

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Dedications

In memory of Pei Wang,

who first introduced me to this research topic and whose mentorship continues to guide me.

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List of Acronyms

HVDC	High Voltage Direct Current
MMC	Modular Multilevel Converter
CPI	Control Performance Indices
VSC	Voltage Source Converter
EMT	Electromagnetic Transient
LCC	Line Commuted Converter
StnCPI	Station-CPI
SysCPI	System-CPI
EvtCPI	Event-CPI
UnifiedSysCPI	Unified System CPI
StnRefScore	Station Performance Reference Score
SysRefScore	System Performance Reference Score
MIPI	Multi-Infeed Interaction Performance Index

LCC	Line-Commutated Converter
PSS	Power System Stabilizer
SCR	Short Circuit Ratio
POC	Point of Connection
CCSC	Circulating Current Suppression Control
NLC	Nearest Level Control
CVB	Capacitor Voltage Balancing
SCR	Short Circuit Ratio
ESCR	Effective Short Circuit Ratio
CCT	Critical Clearing Time
RoCoF	Rate of Change of Frequency
CFII	Commutation Failure Immunity Index
UIF	Unit Interaction Factor
MIIF	Multi-Infeed Interaction Factor
LCC	Line-Commutated Converter
MAP	Maximum Available Power
MPC	Maximum Power Curve

CSCR	Composite Short Circuit Ratio
WSCR	Weighted Short Circuit Ratio
VSC	Voltage Source Converter
TOV	Transient Over Voltage
MIESCR	Multi-Infeed Effective Short Circuit Ratio
VSF	Voltage Sensitivity Factor
CSI	Control Sensitivity Indices
AISCR	Apparent Increase in SCR
HMIESCR	Hybrid Multi-infeed ESCR
MVIF	Multi-Infeed Voltage Interaction Factor
LVRT	Low-Voltage-Ride-Through
LVRTCA	LVRT Capability Area
FRT	Fault Ride Through

Chapter 1

Introduction

This chapter introduces the motivation, challenges, objectives, scope, and core contributions of this thesis. It provides the technical and practical context surrounding multi-infeed high-voltage direct current (HVDC) systems, particularly as power utilities transition toward more resilient and modern grids. Drawing upon industry trends and project-specific challenges, it lays the foundation for the Control Performance Index (CPI) framework developed in later chapters.

1.1 Motivation

As the use of high-voltage dc (HVDC) transmission expands, adding a new link or refurbishing an existing one often places multiple HVDC terminals in the same AC area, forming *multi-infeed HVDC* corridors. This challenge is particularly relevant for Manitoba Hydro, which is exploring modernization options for its aging Bipole 1 Line-Commutated Converter (LCC) system. In the multi-infeed HVDC settings, various topologies—such as full voltage source converter (VSC) configurations (VSC at both rectifier and inverter),

mixed LCC–VSC links (LCC rectifier with VSC inverter), and diverse control modes—are increasingly common. However, evaluating system stability and resilience under AC faults becomes significantly more complex. Classic planning tools such as Short-Circuit Ratio (SCR), Effective SCR (ESCR), and Multi-Infeed Interaction Factors (MIIF) were developed for LCC-based systems and seldom capture the *controller-dependent dynamics and frequency-coupled interactions* that dominate multi-infeed systems containing both LCC and VSC converters.

Waveform-based metrics from electromagnetic transient (EMT) studies, including commutation failure immunity (CFII), transient over-voltage (TOV), critical clearing time (CCT), and frequency nadir, offer higher fidelity but lack cohesion. These indices are typically computed in isolation, emphasize extreme values rather than duration, and fail to convey the integrated severity of post-fault disturbances.

This gap between traditional indices and practical system needs motivates the development of a unified, controller-sensitive evaluation framework. The proposed approach integrates voltage and frequency behavior into a single comparative metric, providing utilities such as Manitoba Hydro with a transparent and scalable tool for screening HVDC upgrade alternatives across different topologies, control modes, and power ratings.

1.2 Research Objectives and Questions

Building on the above motivation, planning a new HVDC link or modernizing an existing corridor typically requires comparing several alternatives across *converter topology* (LCC, VSC, or mixed LCC&VSC schemes), *converter ratings*, and *control modes*. This thesis aims to develop a robust and generalizable method for quantifying post-fault recovery performance

in multi-infeed HVDC networks. The central research questions are:

- O1:** Formulate control-sensitive metrics for post-fault voltage, frequency, and power traces as scalar performance indices.
- O2:** Derive weighting and aggregation scheme that consolidates diverse performance indices—spanning multiple fault scenarios and converter terminals—into a single, holistic metric, and a novel approach enables planners to distill the results of multiple of EMT simulations into one concise scalar for each HVDC design alternative, supporting efficient comparison and decision-making.
- O3:** Embed an automated workflow for extracting Control Performance Indices (CPIs) from EMT simulation data using a standardized PSCAD to Python toolchain, enabling scalable and repeatable analysis for large parametric study sets.
- O4:** Benchmark the proposed CPI-based metrics across three realistic Bipole 1 modernization scenarios—spanning different topologies, power ratings, and control modes—by evaluating their corresponding fault ride-through (FRT) boundaries and overall disturbance resilience.

1.3 Scope and Assumptions

Scope of the study

- **System events:** Time-domain EMT simulations of solid and high-impedance three-phase AC faults with multiple durations, applied at converter buses in multi-infeed settings.

- **Technology options compared:** Two modernization configurations are evaluated: (i) an all-MMC VSC system and (ii) a mixed scheme with an LCC rectifier and an MMC-based VSC inverter. Both are derived from publicly available CIGRÉ benchmark models and are vendor-agnostic [1, 2].
- **Network footprint:** A 150-bus Manitoba-equivalent reduced network is used. Dynamic behavior at interconnection boundaries is represented with IEEE standard synchronous machine models to emulate neighbouring utilities.

Modelling assumptions

- **Generic controllers:** VSC stations use half-bridge MMCs with current-controlled submodules (CCSC) and nearest-level control (NLC). No vendor-specific or advanced proprietary control logic is included.
- **Converter current limits:** Current limiting behavior of VSCs plays a critical role in determining both fault ride-through (FRT) capability and post-fault recovery performance. In this study, a 3 kA IGBT maximum current capacity is assumed, based on publicly available device data [3–5]. Higher current ratings now emerging in commercial MMC valves would raise the attainable CPI scores, and hence the reported CPI-based performance scores may be conservative estimates subject to improvement with future hardware developments.

Outside the Thesis’s Scope

- Full-bridge MMCs and mixed-arm FB/HB implementations.
- Vendor-specific protection, supervisory, or feature-enhanced controllers.

1.4 Technical Background

This section reviews key HVDC technologies and highlights the unique challenges introduced by multi-infeed configurations. It also surveys existing evaluation indices, identifying their limitations in capturing controller dynamics and providing unified voltage–frequency resilience assessment.

1.4.1 Overview of HVDC Technologies

HVDC systems can be broadly categorized into line-commutated converters (LCC), voltage-sourced converters (VSC), and mixed LCC and VSC combinations. LCC systems are mature and cost-efficient but vulnerable to commutation failures and reactive power demands. VSC systems, based on MMC technology, offer independent active/reactive power control, black-start capabilities, and better performance in weak grids. Mixed schemes, where the LCC is retained at the rectifier and an upgraded design of VSC at the inverter, attempt to merge the strengths of both.

1.4.2 Multi-Infeed Challenges

When multiple converters operate within the same AC region, their interactions complicate planning and protection. The effective fault level at each terminal is reduced as Short-Circuit Ratio(SCR) dilution, and dynamic events such as faults or power swings can induce mutual instabilities. Metrics such as Multi-Infeed Interaction Factor (MIIF) [6], and rating-weighted MIIF(WMIIF) [7] were developed to estimate these coupling effects but are often based on fundamental frequency and LCC based HVDC technology. Weak networks amplify transient over-voltages (TOV) [8, 9] and degrade Commutation-Failure Immunity

(CFII) [10,11] decrease Maximum-Available-Power (MAP) [12], and also depress the Voltage-Sensitivity Factor (VSF) [13,14], while low inertia raises the Rate of Change of Frequency (RoCoF) and deepens frequency nadirs [15–17].

Survey of Existing Evaluation Indices: Table 1.1 summarises the most frequently used metrics and highlights their blind spots.

Table 1.1: Traditional Indices and Their Coverage

Index	Voltage	Frequency	Controller-Aware
SCR/ESCR/WSCR	✓ (static)	–	✗
MIIF/WIIF	✓ (impedance)	–	✗
MAP/VSF	✓ (quasi-static)	–	✗
CFII, TOV	✓ (Simulation)	–	partly
CCT, RoCoF, Nadir	–	✓ (simulation)	partly

1.4.3 Limitations of Existing Evaluation Indices

- **SCR/ESCR:** Fast and widely used but limited to 50/60 Hz behavior and incapable of capturing frequency/voltage coupling or fast control actions.
- **MAP/VSF:** Useful for static voltage margin estimation, but ignore closed-loop dynamics and become unreliable near the loadability limit.
- **MIIF family:** Provide useful insight into electrical proximity and voltage amplification, but lack generalizability to the VSC converter category.
- **Simulation-based (CCT, CFII, TOV):** High fidelity but computationally intensive and fragmented by phenomenon.

1.5 Thesis Contributions

The main technical contributions of this thesis are mapped to the core chapters as follows:

- **Chapter 3:** Construction of an EMT benchmark capturing three plausible Bipole 1 modernization pathways (VSC and mixed LCC—Bipole 1 rectifier—/VSC—Bipole 1 inverter) at multiple ratings
- **Chapter 4:** Formalization of the CPI framework—including per-unitization, fault weighting (Station-CPI), terminal aggregation (Event-CPI), and double-aggregation (SysCPI).
- **Chapter 5:** Visualization and analysis of CPI-based fault characteristic curves. Quantifies low-voltage ride-through (LVRT) boundaries and resilience under varying post-fault voltages.
- **Chapter 6:** Introduction of a graphical user interface (GUI) and Python-based toolchain for CPI batch processing. Enables a speed-up over traditional EMT screening.

1.6 Thesis Structure

Chapter 1 frames the planning challenge in multi-infeed corridors; states research objectives, scope, and assumptions.

Chapter 2 reviews literature on system-strength, quasi-static and simulation-based indices, exposing gaps that motivate CPIs.

Chapter 3 details the Manitoba Hydro three-bipole EMT model and describes converter control architectures.

Chapter 4 introduces the CPI framework, including mathematical formulation and aggregation strategies.

Chapter 5 analyzes CPI performance and fault ride through capability under different alternatives and converter configurations in the multi-infeed system

Chapter 6 presents a streamlined analysis workflow and demonstrates how the developed CPI framework can be operationalized into a quantitative scoring system for comparing HVDC planning alternatives.

Chapter 7 summarises findings, engineering implications, limitations and future research avenues.

Chapter 2

Literature Review and Evaluation

2.1 Review of System Indices for Multi-Infeed HVDC Evaluation

High-voltage direct-current (HVDC) performance indices reported in the literature can be grouped into four methodological families, each reflecting a distinct time-scale, modelling depth, and practical use-case. Figure 2.1 provides a roadmap for existing HVDC system indices to be discussed in this chapter. **(i) System-strength indices**—rooted in the Short Circuit Ratio (SCR) concept—measure the Thévenin stiffness available at a converter point of common coupling and remain the first-pass screening tool for planning studies. **(ii) AC/DC interaction indices** quantify how converters exchange electromagnetic energy with nearby generators or with each other; they bifurcate into fundamental-frequency factors (Unit Interaction Factor (UIF), classical and weighted MIIF) and higher-frequency scan techniques (harmonic injection, impedance-radiality scans) **(iii) Quasi-static margin indices** such as Maximum Available Power (MAP), Voltage Sensitivity Factor (VSF) and

Control Sensitivity Indices (CSI) linearise the power–voltage manifold and act as analytical tools to quantify the voltage and power stability limits by leveraging a combination of numerical methods and analytical techniques. **(iv) Simulation-derived disturbance indices** translate simulation waveforms into composite figures—e.g. Commutation Failure Immunity Index (CFII), Critical Clearing Time (CCT), Rate of Change of Frequency (RoCoF) and Transient Over Voltage (TOV) scores—to capture fast commutation, voltage violation or frequency excursions.

Applications and Screening Value System indices offer simplified approaches that aim to flag potential issues for further investigation. In practical studies, they help reduce the number of scenarios that need to be considered in detailed simulations—particularly for contingency ranking and sensitivity screening. By quantifying the likelihood of converter interactions and identifying the most critical locations, indices enable system planners to prioritize the most impactful operating conditions and fault scenarios. Furthermore, certain indices can offer early insights into the likely type of instability (e.g., commutation failure, voltage collapse, harmonic resonance) before full electromagnetic transient (EMT) simulations are performed.

Throughout this section, each family is introduced from the principles, application, and critically assessed for scalability to modern multi-infeed VSC or Mixed LCC–VSC grids.

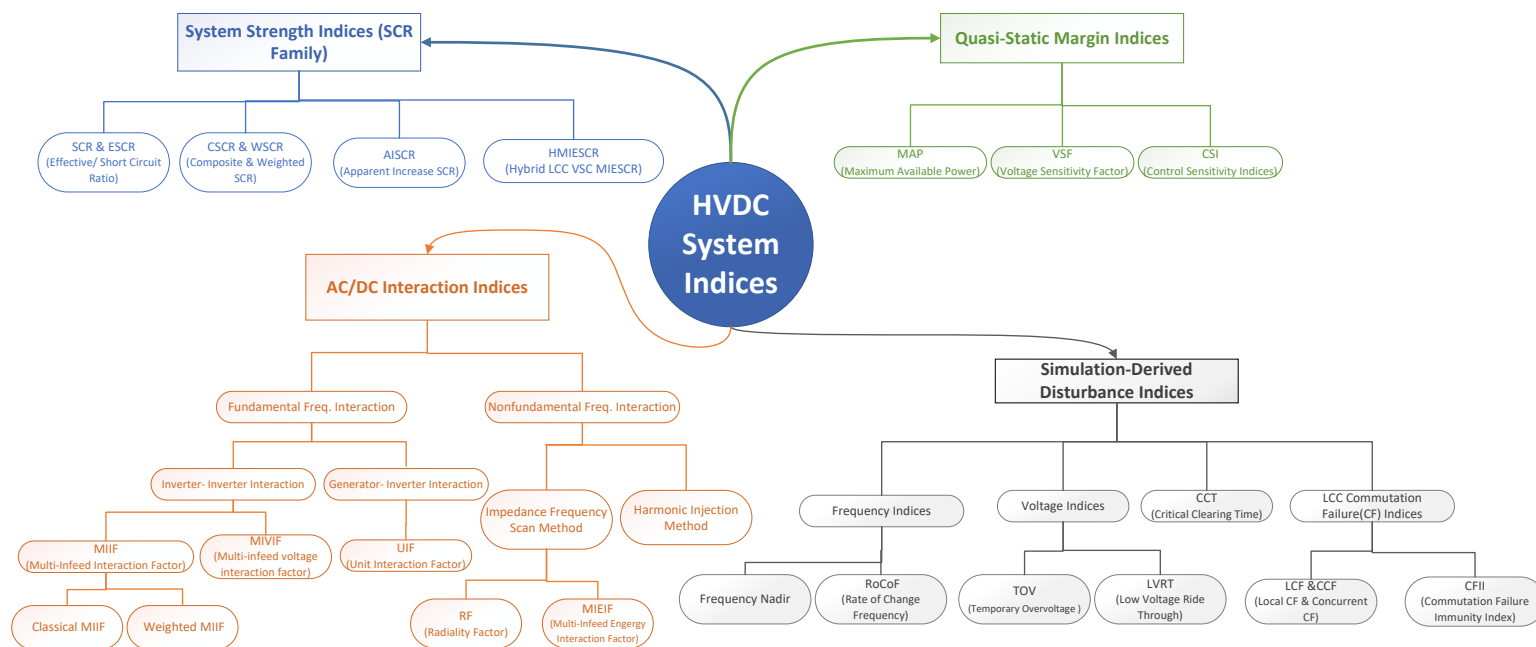


Figure 2.1: Overview of HVDC System Evaluation Indices

2.1.1 System Strength Indices (SCR Family)

System-strength indices, particularly the short-circuit ratio (SCR), are widely used in industry for their simplicity and reliance on standard model data and software tools. They have been effective historically when system dynamics were dominated by synchronous generators. In typical applications, fault-level data at converter buses are used, and synchronous machines are modeled as Thévenin-equivalent AC voltage sources, thereby neglecting the detailed dynamics of excitation systems, governors, and power-system stabilizers. This subsection introduces several extensions of the basic SCR concept—Effective Short Circuit Ratio (ESCR), Composite Short Circuit Ratio (CSCR), Weighted Short Circuit Ratio (WSCR), and Apparent Increase in SCR (AISCR)—and discusses their concepts, applications, and limitations.

2.1.1.1 Short Circuit Ratio (SCR) and Effective Short Circuit Ratio (ESCR)

Conceptual Basis and Classical Use-Cases: The *short-circuit ratio* (SCR) is the ratio between the three-phase fault level at a converter’s point of connection and the link’s rated active power. Its effective extension, $ESCR$, additionally subtracts the reactive support already connected at that bus, thereby reflecting the net short-circuit capacity actually available to the converter [18].

$$SCR = \frac{S_{AC}}{P_{DC}} \quad (2.1)$$

$$ESCR = \frac{S_{AC} - Q_C}{P_{DC}} \quad (2.2)$$

where S_{AC} denotes the three-phase fault level (in MVA) at the converter bus, and P_{DC} is

the rated power of the HVDC link, Q_C represents the total installed reactive compensation at the bus (in Mvar).

These scalar indices were introduced to provide planners with an expedient gauge of “system strength”: values above roughly 3 imply that a line-commutated converter (LCC) can operate with minimal risk of commutation failure or voltage collapse, whereas values below 2 flag the need for special design measures such as synchronous condensers or fast reactive compensation [19]. Because SCR and ESCR can be computed from basic load-flow or short-circuit studies, they remain the de-facto first screening tool for siting new HVDC terminals, assessing fault-recovery margins, and comparing alternative reinforcement options.

Empirical Insights, Enhancements, and Caveats: Subsequent investigations have clarified both the utility and the limitations of SCR/ESCR. Large-system EMT and RMS simulations confirm that ESCR correlates with transient-overvoltage magnitudes after severe AC faults; however, in multi-infeed environments each inverter “dilutes” the effective fault level seen by its neighbors [6]. To account for multi-infeed effects, composite variants such as CSCR, WSCR, and Multi-Infeed Effective Short Circuit Ratio (MIESCR) have been proposed and validated on weak-grid wind farms or multi-infeed HVDC connections, where the conventional threshold of 3 proved overly optimistic [9]; these extended indices are explored in §2.1.1.2. More recent dynamic-modeling guidelines recommend complementing ESCR with voltage-sensitivity and impedance-based metrics, noting that frequency-dependent impedances, converter controls, and fast power-electronic devices cannot be captured by a single static ratio [20]. Thus, while SCR/ESCR remains indispensable early-stage screening, it should be supplemented with time-domain studies whenever VSC technology, high converter density, or complex passive networks are involved.

2.1.1.2 Composite Short Circuit Ratio (CSCR) and Weighted Short Circuit Ratio (WSCR)

Multi-infeed renewable HVDC schemes differ markedly from classical LCC links: converters are often clustered at remote collection hubs, while the Point of Connection (POC) is located tens of kilometres away and connected through long export cables and step-up transformers. Conventional single-bus SCR therefore over-estimates the network stiffness at the POC because it ignores the impedance between individual inverter terminals and the on-shore grid. Two composite metrics—CSCR and WSCR—have been developed to capture this effect and to provide a first-pass screening tool for weak-grid integration studies.

Composite Short-Circuit Ratio (CSCR) When several converter stations are electrically close, they may be approximated by a single “lumped” inverter connected to a fictitious common bus, *inv_com*. With that simplification, the system strength is evaluated from the short-circuit capacity at the lumped bus:

$$\text{CSCR} = \frac{S_{\text{SC}}^{\text{inv_com}}}{\sum_{i=1}^N P_{\text{dc},i}}, \quad (2.3)$$

where $S_{\text{SC}}^{\text{inv_com}}$ is the three-phase fault level (in MVA) calculated at *inv_com* with all converter terminals short-circuited, and $P_{\text{dc},i}$ is the rated active-power capability of inverter i . The index therefore treats the cluster as a single, large converter and is easy to implement in standard short-circuit programs [21].

Limitation of CSCR: Because CSCR neglects the transfer impedances between individual stations, it implicitly assumes a “rigid” inter-converter connection. In meshed collector networks this leads to overly pessimistic estimates of system strength and may flag benign

cases as problematic [22].

Weighted Short-Circuit Ratio (WSCR) The WSCR formulation retains the individual converter buses but weights each local fault level by the corresponding converter rating:

$$w_i = \frac{P_{dc,i}}{\sum_{k=1}^N P_{dc,k}}, \quad (2.4a)$$

$$\text{WSCR} = \frac{\sum_{i=1}^N S_{sc,i} w_i}{\sum_{k=1}^N P_{dc,k}} = \frac{\sum_{i=1}^N S_{sc,i} P_{dc,i}}{(\sum_{k=1}^N P_{dc,k})^2}, \quad (2.4b)$$

with $S_{sc,i}$ denoting the short-circuit MVA at inverter bus i . Equation (2.4b) down-weights small converters and emphasises the contribution of high-rated stations, yielding a more realistic representation of how fault current is shared in a multi-infeed cluster [23].

Operational Experience and Thresholds: The WSCR metric has gained traction in real-time strength monitoring. In the Texas Panhandle, for example, the system operator curtails wind generation whenever $\text{WSCR} \leq 1.5$ to stave off system failure cascades and voltage-instability risk [24].

CSCR and WSCR Pros & Cons: CSCR delivers a fast, conservative estimate by collapsing a group of electrically close inverter-based resources (IBRs) into a single equivalent node. WSCR refines this by retaining individual converter buses but weighting each one according to its rated power contribution. Both indices remain *quasi-static*—they neglect frequency-dependent impedance effects and converter-control dynamics—and should there-

fore be complemented by interaction-factor and voltage-sensitivity analyses in weak grids with multiple HVDC links.

Despite their simplifications, CSCR and WSCR offer clear advantages for rapid screening in regions with high IBR concentration. In such settings, where dozens or even hundreds of converters are sited within a compact geographical area, these indices allow efficient first-pass system strength assessment. Instead of calculating SCR or ESCR for each individual inverter—an approach that quickly becomes cumbersome—CSCR enables planners to treat the entire IBR cluster as a single aggregate entity with a common short-circuit level. WSCR offers a middle ground, evaluating individual fault levels but aggregating the plant’s total DC rating in the denominator. This makes CSCR and WSCR particularly well-suited for ranking plant vulnerabilities and pinpointing the weakest terminals in large-scale IBR zones.

2.1.1.3 Apparent Increase in Short-Circuit Ratio (AISCR)

Definition and Conceptual Basis: The *apparent increase in short-circuit ratio* quantifies how much a dynamic reactive source at an inverter terminal “acts as if” it had stiffened the ac network. For any chosen performance index—e.g. maximum-available power (MAP), temporary over-voltage (TOV), commutation-failure immunity (CFII) or fault-recovery time—the compensated dual-infeed system is first evaluated. The same index is then reproduced on an *equivalent* single-infeed study by raising the system short-circuit level until both results match. The difference between this *apparent* SCR and the original SCR is reported as

$$\text{AISCR} = \text{SCR}_{\text{equiv}} - \text{SCR}_{\text{orig}},$$

so that positive values represent the compensator’s perceived strengthening effect [25].

Findings From the Initial Dual-Infeed Study: A 1000 MW LCC inverter connected to a 300 MW VSC supporting 133 Mvar of reactive reserve exhibited MAP and TOV behaviours identical to those of a single-infeed LCC operating at an SCR of 3.03, although the physical network offered only 2.5. Hence an $\text{AISCR} \approx 0.53$ was inferred [25]. Transient studies, however, revealed that the single-infeed surrogate was rather *pessimistic*: fault-recovery times of the real dual-infeed arrangement were faster than predicted, showing that AISCR derived solely from MAP cannot perfectly emulate every dynamic aspect [26].

Extended Multi-Criterion Approach: Subsequent work introduced four parallel AISCR traces—based on MAP, TOV, CFII and fault-recovery time—using the same benchmarking procedure. Plotting these curves against compensator rating allows either a conservative (minimum-of-four) or an optimistic (arithmetic-mean) interpretation, thereby capturing the fact that compensators improve some criteria more than others [27]. Results confirm that synchronous condensers and STATCOMs deliver almost linear gains in $\text{AISCR}_{\text{MAP}}$, whereas $\text{AISCR}_{\text{CFII}}$ saturates once the compensator current limit is reached [28].

Limitations and Open Issues: AISCR is not a stand-alone design metric and is best interpreted as a *relative* comparison index rather than a substitute for conventional strength metrics and time-domain verification. Its numerical value depends on: (i) *metric-specific sensitivity*—a single compensator yields different apparent gains ($\text{AISCR}_{\text{MAP}}$ typically largest; $\text{AISCR}_{\text{TOV}}$ smaller; $\text{AISCR}_{\text{CFII}}$ saturating at current limits; $\text{AISCR}_{\text{FRT}}$ for recovery time) [28]; (ii) *data requirements*—averaging multiple curves provides balance [28] but requires all corresponding EMT/RMS studies; and (iii) *operating-point dependence*—the compensator must retain reactive headroom; near Mvar or current limits (e.g., at peak export) its voltage-support ability collapses and AISCR reverts toward zero [26]. Hence AISCR should be

evaluated across the dispatch range rather than at a single snapshot.

2.1.1.4 Hybrid Multi-infeed ESCR (HMIESCR)

Concept and Definition Relying on the MVIF-based virtual single-infeed reduction, the Hybrid Multi-infeed ESCR (HMIESCR) is defined for each inverter bus i as [29]

$$\text{HMIESCR}_i = \frac{V_i^2 \left(Y_{ii} - \sum_{j \neq i} Y_{ij} \text{MVIF}_{ji} \right)}{P_{dci}^N}, \quad (2.5)$$

with Y_{ii} the self-admittance at bus i , Y_{ij} the mutual admittance to bus j , V_i the rated ac voltage and P_{dci}^N the rated dc power. MVIF is a voltage vector influence factor in the multi-infeed system, similar to the traditional Multi-Infeed Interaction Factor (MIIF), which will be discussed in Section 2.1.3.1 [30].

For the reduced two-bus equivalent the paper demonstrates that the reduced QV -Jacobian's smallest eigenvalue $\lambda_{\min}$ crosses zero when

$$\text{HMIESCR}_{\text{crit}} \approx 1.5,$$

so the index gives a direct, planning-level voltage-stability margin analogous to the classical ESCR used for single-infeed LCC links.

Applications and Key Findings Using the four-infeed benchmark system (2 LCC + 2 VSC) the following trends are reported [29]:

- (a) **VSC control mode:** converting a VSC from reactive-power control to constant-voltage control raises HMIESCR and defers the $\lambda_{\min} = 0$ point, indicating a larger voltage-stability margin.

- (b) **Converter mix / topology:** replacing an LCC by a VSC, or increasing the population of VSCs in constant-voltage control mode, increases HMIESCR; conversely, removing a VSC or switching to reactive power mode lowers HMIESCR.
- (c) **STATCOM substitution:** exchanging a VSC for an equally-rated STATCOM still improves HMIESCR relative to an all-LCC case, and acts similarly to the VSC in terms of the voltage stability improvement.

Across various scenarios, the deviation between the critical HMIESCR and the $\lambda_{\min} = 0$ benchmark remains within $\pm 5\%$, confirming the index as a rapid screening tool for converter-mix optimization and siting of dynamic voltage support.

Limitations and Practical Considerations

- *Network-reduction effort.* Equation (2.5) requires mutual admittances Y_{ij} at the inverter buses. In real grids the electrical path between two terminals often runs through several substations; hence Kron reduction and admittance-matrix re-ordering are needed to obtain the condensed Y_{ij} values, adding modelling effort for large systems [31].
- *Residual error* – Although the mean absolute error relative to the $\lambda_{\min}$ benchmark is below 3 %, some stressed cases approached 5 % [30]; narrow margins should still be verified with detailed EMT simulations.

Within these bounds, HMIESCR provides planners with a rigorously derived, single-number proxy for voltage-stability margin that retains validity across mixed LCC/VSC fleets, alternative VSC control strategies, and STATCOM feeders—extending the classical ESCR logic into Mixed multi-infeed networks.

SCR Family Indices Summary

The SCR family offers a fast, low-data entry point for gauging “electrical stiffness” at an HVDC terminal. Classical **SCR** and **ESCR** remain indispensable for single-infeed LCC planning, but their scalar nature ignores inter-converter coupling, frequency-dependent impedances, and control dynamics. Composite extensions—**CSCR**, **WSCR**, and **AISCR**—partially correct these omissions by lumping or weighting multiple terminals and by quantifying the apparent stiffening produced by dynamic reactive plant; however, they are still quasi-static and metric-specific. The rigorously derived **HMIESCR** generalises the concept to mixed LCC/VSC clusters, reproduces the ESCR limit of 1.5 for voltage stability, and reduces systematic error to below $\approx 5\%$ when compared with full eigenvalue analysis. Practitioners should therefore use HMIESCR (or at least WSCR) for early multi-infeed screening and reserve detailed EMT studies for narrow-margin or control-sensitive cases.

2.1.2 Quasi-Static Margin Indices

Quasi-static techniques evaluate an AC/DC network as a sequence of steady states, bypassing detailed electromechanical and electromagnetic dynamics. Their appeal lies in the ability to rapidly analyze operating conditions and screen equipment parameters at negligible computational cost. Three classical indices recur in the literature—the Maximum-Available-Power (MAP), the Voltage-Sensitivity Factor (VSF), and the Control-Sensitivity Index (CSI)—each translating nonlinear relationships on the $P-V-Q$ manifold into a single scalar. These indices excel at locating the static boundary of voltage or power stability; however, they inherently omit fast converter-control and network dynamics and should be cross-checked with time-domain studies whenever the quasi-static limit is approached.

2.1.2.1 Voltage Sensitivity Factor (VSF)

Definition and Conceptual Basis The voltage-sensitivity factor quantifies the local $Q - V$ characteristic as the incremental AC-voltage change (dV) due to a small reactive-power perturbation (dQ) at the commutation bus:

The formal expression of the voltage sensitivity factor is given

$$\text{VSF} = \frac{dV}{dQ}. \quad (2.6)$$

where dV is the resulting incremental (or decremental) change in bus voltage. A negative slope signifies that additional reactive demand depresses the local voltage and vice-versa. Such dQ excursions arise from dc-current ramps, shunt operations, generator de-excitation or nearby faults [12].

Applications of VSF Similar to traditional QV analysis in AC power system voltage stability studies [32], the application of VSF is broad. Several typical uses include:

- *Small-signal voltage damping:* the magnitude of VSF offers a first-order estimate of how the ac voltage will oscillate under minor disturbances [13].
- *Control-mode selection:* In weak AC systems, the sign of VSF guides HVDC control choices: at low SCR, a negative VSF cautions against constant-power rectifier with fixed- γ inverter control, whereas constant-current rectifier control tends to keep VSF positive and the operating point stable [14].
- *Critical ESCR identification:* plotting VSF versus ESCR reveals the ESCR at which VSF goes to infinity, a static boundary that coincides with the MAP turning point

discussed later [12].

- *Weak-bus flagging*: as the operating point approaches the nose of the $P-V$ curve, VSF grows large; buses with very large VSF are candidates for additional voltage support [6].

Limitations and Practical Caveats

- **Controller-implementation hurdle**: While it may appear intuitive to define regions of voltage irregularity based on the sign of the VSF, the functionality of a control scheme for detecting changes in the VSF sign is seldom available in the field controllers; such a control strategy is considered highly hypothetical and not feasible for practical power system operations [19].
- **Numerical ill-conditioning near the nose**: As the system approaches the $P-V$ nose point, $VSF \rightarrow \infty$; most load-flow or continuation algorithms experience Jacobian singularities and fail to converge, making it difficult to locate the exact static-instability boundary [33].

2.1.2.2 Maximum Available Power (MAP) and the Maximum Power Curve (MPC)

Conceptual Basis The *maximum power curve* (MPC) portrays how the dc-side real power P_{dc} of an LCC converter varies with dc current I_{dc} when *all other controllable quantities remain frozen*—i.e. transformer tap positions, extinction angle, and shunt-compensation switchgear are held constant [12]. Starting from the rated operating point, I_{dc} is incrementally increased. Because the reactive-power demand of an LCC grows roughly in proportion

to its active power ($Q_{dc} \approx 0.4 - 0.6 P_{dc}$), each current step withdraws additional dQ from the ac network, depressing the converter-bus voltage. Beyond a certain point the accompanying drop in dc voltage overpowers the rise in current: dP_{dc}/dI_{dc} changes sign and the curve peaks. That apex is the *maximum available power* (MAP); the associated current is I_{MAP} . On an ac-system portrait the same condition coincides with the nose of the $P-V$ curve, where the voltage-sensitivity factor transitions from positive to infinite and then negative.

Limitations and Cautionary Notes

- **Quasi-static metric:** MAP derives from steady-state $P_{dc}-I_{dc}$ relationships and does not capture dynamics such as fault recovery, control-mode switching, or transient instabilities [12, 14].
- **Infeasible operating point:** The MAP point often aligns with the AC system's point of minimum loadability (PML) and may be impractical—requiring excessive DC current or critically low AC voltage—well beyond current-order ceilings or protection thresholds. MAP is best viewed as a stress test indicating theoretical margin, not a dispatch target [19].
- **Load-model sensitivity:** The inferred margin depends on load modeling; dynamic or voltage-dependent loads shrink apparent headroom compared with constant-power/constant-impedance assumptions [19].

2.1.2.3 Control Sensitivity Indices (CSI)

Concept and Formulation The *Control Sensitivity Index* (CSI) is a small-signal metric that gauges how effectively an HVDC or FACTS control loop can influence its intended state

variable at a given operating point. It is defined as the incremental ratio

$$\text{CSI} = \frac{\partial x_{\text{ctrl}}}{\partial u_{\text{cmd}}}$$

where x_{ctrl} is the *controlled* quantity (e.g. extinction angle γ , bus voltage V , dc power P_{dc}) and u_{cmd} is the directly-manipulated *controlling* variable (e.g. firing angle α , reactive-current order, tap ratio). In practice, CSI is extracted from the reduced Jacobian of the ac/dc load-flow equations: columns associated with the fixed variables are removed, and the remaining $J_{\text{op}}^{-1} J_u$ product gives $\partial x / \partial u$ for each control mode [34]. A well-behaved controller requires $\text{CSI} < 0$ (negative feedback) and a magnitude that is neither too small (sluggish response) nor too large (risk of oscillation).

Typical Applications

- **Controller tuning and non-linear gain scheduling**—CIGRÉ TB 222 shows that CSI profiles can be used to pre-compute variable gains so that loop bandwidth remains approximately constant as operating conditions change [19].
- **Mode comparison in weak grids**—Nayak *et al.* used CSI to compare constant- γ , constant- V , and constant- P modes for an inverter at $\text{ESCR} < 1$; the index correctly predicted that constant- V control is inherently more stable than classical constant- γ control in very weak systems [34].
- **Quick stability screening**—A positive CSI (or one whose magnitude crosses a designer-specified threshold) flags a potential loss of small-signal stability without having to perform time-domain EMT simulations.

Caveats and Practical Limitations

- *Quasi-static assumption:* CSI is derived from the steady-state Jacobian and therefore ignores dynamic states of converters, machines, or PLLs; a controller that is stable per CSI may still fail under fast faults or resonance [34].
- *Operating-point dependence:* Large load-flow excursions or tap-changer actions can alter J_{op} radically, requiring CSI to be recomputed; fixed-gain designs based on a single CSI value may become inadequate [19].
- *Model fidelity:* Accurate Jacobian entries rely on detailed converter, filter, and control representations; oversimplified phasor models can yield misleading CSI magnitudes [34].

Thus, CSI is a compact analytical complement to indices such as MAP, VSF, and ESCR—well suited for sensitivity screening and gain scheduling—but it must be paired with time-domain or frequency-domain studies to capture control interactions and fast electromagnetic transients.

2.1.3 AC/DC Interaction Studies Indices

Interaction indices evaluate how converters dynamically influence each other and nearby synchronous machines through shared AC network pathways. This section categorizes interaction studies into three major groups based on the nature and frequency content of the coupling mechanisms. First, *converter–converter fundamental-frequency interaction factors* (e.g., MIIF, W-MIIF, MVIF) assess impedance-based voltage coupling between converters in RMS studies. Second, the *unit interaction factor (UIF)* quantifies the interaction between converters and synchronous generators, offering a simplified metric for identifying

potentially resonant converter–generator pairs. Finally, *nonfundamental-frequency interaction indices* extend the analysis to subsynchronous and harmonic regimes using tools such as harmonic-injection MIIF, the radiality factor (RF), and the multi-infeed energy interaction factor (MIEIF). Together, these indices offer a multi-layered framework for early-stage stability screening across a wide frequency spectrum and device mix.

2.1.3.1 Converter–Converter Fundamental-Frequency Interaction Factors

Converter–converter interactions at the fundamental frequency have been extensively analyzed and are routinely implemented in RMS phasor-domain simulation tools. This subsection summarizes three representative indices used for such analysis: (1) the classical *Multi-Infeed Interaction Factor (MIIF)*, (2) its rating-weighted extensions that incorporate active or reactive power scaling, and (3) the *Multi-Infeed Voltage Interaction Factor (MVIF)*, which generalizes MIIF by capturing both magnitude and phase-angle components of the voltage response. Collectively, these indices offer a fast and practical means of screening for potential voltage support conflicts or reactive power coupling among closely located HVDC converters in multi-infeed environments.

1) Classical Multi–Infeed Interaction Factor (MIIF) The *Multi-Infeed Interaction Factor* (MIIF) quantifies how a small voltage disturbance applied at one converter bus (i) propagates to the terminal of another converter (j). Using a 1 % voltage decrement as the perturbation, the factor is defined as the linear voltage ratio

$$\text{MIIF}_{j,i} = \frac{\Delta V_j}{\Delta V_i},$$

with values ranging from 0 (no coupling) to 1 (same bus) [6]. Because the test signal is intentionally small, control actions remain inactive; MIIF therefore captures the *network-impedance* pathway that links the two converters.

MIIF enters HVDC planning studies chiefly through the *Multi-Infeed Effective Short-Circuit Ratio* (MIESCR) that extends the single-infeed ESCR to account for neighbouring links:

$$\text{MIESCR}_a = \frac{\text{SCC}_a - Q_{f,a}}{P_{\text{dc},a} + \sum_{b \neq a} (\text{MIIF}_{b,a} P_{\text{dc},b})},$$

where SCC_a is the short-circuit capacity at bus a and $Q_{f,a}$ the reactive compensation already installed at bus a . In essence, each adjacent converter contributes an $\text{MIIF}_{b,a} P_{\text{dc},b}$ “virtual load” that penalises the available short-circuit strength at a [6].

Typical use-cases: MIIF and MIESCR are widely adopted for pre-construction screening of line-commutated HVDC schemes to ensure that converter reactive-power swings at one terminal will not jeopardise voltage stability at another. Values of $\text{MIESCR} < 2.5$ signal that additional reactive compensation or a change in converter control-mode may be required.

Limitations of MIIF:

- The 1 % perturbation is too small to excite converter controls, so MIIF neglects control-interaction channels—acceptable for LCCs but not for tightly regulated VSCs or FACTS devices [20].
- The metric considers the approximately LCC relation $Q \approx 0.5P_{\text{dc}}$; for VSCs (decoupled P - Q) or STATCOMs ($P_{\text{dc}} = 0$) the $\text{MIIF } P_{\text{dc}}$ term can not estimate true interaction strength [35].

These shortcomings motivate the weighted extensions introduced below.

2) Rating-Weighted MIIF (W–MIIF) To include devices whose active and reactive ratings differ, the MIIF is augmented by a normalising weight that reflects the *relative size* of the two assessed converters. Two practical forms are recommended [7]:

$$\boxed{\text{W-MIIF}_{j,i}^{(Q)} = \frac{\Delta V_j}{\Delta V_i} \frac{Q_j}{Q_i}} \quad \boxed{\text{W-MIIF}_{j,i}^{(P)} = \frac{\Delta \theta_j}{\Delta \theta_i} \frac{P_j}{P_i}}$$

- W–MIIF^(Q) uses reactive-power ratings Q_j, Q_i and remains valid for STATCOMs or VSCs operating in Q -control.
- W–MIIF^(P) is based on active-power ratings and bus angle deviations ($\Delta\theta$), capturing real-power coupling—useful for devices where P dominates the interaction.

Applications of WMIIF : Both weighted factors enable composite networks containing LCCs, VSC HVDCs, STATCOMs, SVCs or synchronous condensers to be screened on a common scale. In planning tools the procedure is [7]:

1. Compute both Q - and P -weighted MIIF matrices for every pair of converters in the study area.
2. If all entries fall below a designer-specified threshold , remote converters can be replaced by an equivalent Thevenin source—reducing model size without compromising accuracy.

3) Multi-Infeed Voltage Vector Based Interaction Factor

Definition and Rationale The *multi-infeed voltage interaction factor* (MVIF) was proposed in [30] to quantify inter-converter coupling in Mixed LCC–VSC multi-infeed networks. For an incremental real-power change ΔP_i at inverter i , the Multi-Infeed Voltage

Interaction Factor (MVIF) between inverters j and i is defined as the ratio of the *phasor* voltage deviations

$$\text{MVIF}_{ji} = \frac{|\Delta \vec{U}_j|}{|\Delta \vec{U}_i|},$$

where $\Delta \vec{U}_i$ is the complex bus-voltage change (magnitude *and* angle) at inverter i . Unlike the classical MIIF, which employs only voltage magnitudes, MVIF preserves the vector nature of the disturbance and therefore remains well-behaved even when a VSC runs in constant-voltage control and $\Delta U_i = 0$.

Quasi-Static Analytical Evaluation Starting from the linearised AC/DC power-flow model, the closed-form expressions for MVIF that involve the reduced Jacobians matrix forms was mathematically derived, and naturally accommodate all the common VSC LCC control modes including LCC constant- γ , LCC constant- U_{dc} , VSC constant- P/Q , and VSC constant- U_{ac} modes.

Advantages of MVIF Over the Classical MIIF [30]:

- (a) **Unified across converter types:** MVIF is valid for LCC–LCC, VSC–VSC and mixed LCC–VSC pairs under any common control philosophy.
- (b) **No singularity for constant ac voltage controlled VSCs:** MIIF = $\Delta U_j / \Delta U_i$ diverges when $\Delta U_i = 0$, whereas MVIF remains finite because the angle component of $\Delta \underline{U}_i$ is non-zero
- (c) **Vector fidelity:** Using voltage phasors captures both magnitude and phase coupling, giving a truer picture of interaction pathways.

Caveats and Practical Guidance of MVIF

- MVIF is derived from quasi-static (power-flow) linearization; dynamic phenomena outside that bandwidth (e.g., subsynchronous oscillations) are not represented.
- Small but non-negligible errors ($< 5\%$) remain between the analytical solution versus EMT simulations; the possible error source may come from neglected higher-order terms and frequency-dependent network impedances.

The Multi-Vector Interaction Factor (MVIF) is derived from an analytical formulation based on quasi-static equations. While the mathematical foundation of MVIF provides valuable insight into multi-infeed interaction effects, it inherently inherits the limitations associated with quasi-steady-state power-flow model. Despite small errors existing between the analytical solution and simulation results, the advancement of using voltage vectors, rather than only voltage magnitudes as in traditional MIIF, represents an improvement by offering a more comprehensive characterization of system strength.

2.1.3.2 Unit Interaction Factor (UIF) for Converter–Generator Interactions

UIF Concept and Application: Originally proposed for Line-Commutated Converter (LCC) connections in radial power systems [36], the Unit Interaction Factor (UIF) is an index used to gauge how strongly a specific generator may interact with a nearby HVDC converter.

The UIF index for the i -th generator is given by:

$$\text{UIF}_i = \frac{\text{MW}_{\text{HVDC}}}{\text{MVA}_{\text{gen},i}} \left(\frac{\text{SC}_{\text{tot}} - \text{SC}_i}{\text{SC}_{\text{tot}}} \right)^2, \quad (2.7)$$

where MW_{HVDC} is the nominal power of the HVDC converter, $MVA_{gen,i}$ is the capacity of the i -th synchronous generator, and SC_{tot} and SC_i represent the system fault levels at the HVDC converter terminal with and without the generator in operation. This approach, however, assumes a straightforward radial connection between the converter and the generator, making its direct application to more complex or meshed grids questionable.

Subsequent studies [31] extended the UIF concept to handle general network topologies by representing the grid between the converter station and the generator bus as an equivalent π -type circuit (via admittance matrix reduction). The generalized UIF formulation is expressed as:

$$UIF_i = \frac{MW_{HVDC}}{MVA_{gen,i}} \left(\frac{Y_{12}}{Y_1 + Y_{12}} \right)^2, \quad (2.8)$$

where Y_1 is the equivalent shunt admittance at the converter bus and Y_{12} is the branch admittance linking the converter bus to the generator bus (including the generator's subtransient reactance). Although this “network-transfigured” method permits broader applicability, it requires more involved matrix ordering and reduction procedures to isolate Y_1 and Y_{12} .

UIF—Empirical Insights and Findings: [31]—generalize the UIF approach beyond radial LCC circuits by suggesting the use of full admittance matrix ordering and reduction. This broader formulation enables screening of various converter technologies (VSC-HVDC, FACTS devices, and renewable systems) for potential subsynchronous resonance or torsional oscillation issues. At the same time, [37] and [38] indicate that for Voltage Source Converters (VSCs), high UIF values do not necessarily signal higher oscillation risk; advanced control loops can inject sufficient damping to suppress subsynchronous modes, sometimes showing that a “high” UIF correlates with *lower* actual risk. Because UIF is based on *passive* network parameters, it cannot capture vendor-specific control behavior; [38] cautions that no

firm theoretical link ties UIF magnitude to true dynamic stability across fault/oscillatory conditions. Moreover, UIF presumes an effectively inductive network with approximately linear frequency dependence and should not be relied on in series-compensated grids prone to classic SSR [20]. Thus, UIF is best treated as an *initial* screen, especially in multi-infeed or VSC-based environments.

2.1.3.3 Nonfundamental frequency Interaction Factor

The preceding pages assessed *fundamental-frequency* couplings using the original MIIF and its multi-infeed extensions. Planning studies, however, must also guard against *sub-synchronous* (10–40 Hz) and *harmonic* (2–3 kHz) phenomena that excite network resonances, filters, and converter controllers. This subsection therefore introduces two frequency-domain screening families:

(i) a *time-domain* **Harmonic-Injection MIIF** that extends the classical voltage-ratio concept to every harmonic order, and (ii) a *scan-based* approach that extracts interaction indicators—including the **Radiality Factor (RF)** and the **Modified Impedance-Equivalent MIIF (MIEIF)**—directly from a single wide-band network-impedance sweep.

The following paragraphs compare their definitions, practical thresholds, and known limitations.

i) Harmonic-Injection Extension of the Multi-Infeed Interaction Factor The *multi-infeed interaction factor* (MIIF) was originally defined at the fundamental frequency as the sensitivity of the voltage at one converter bus to a small ($\sim 1\%$) voltage dip at another converter bus, yielding values between 0 (no coupling) and 1 (electrical co-location) [6]. [39] generalised this concept to non-fundamental frequencies in order to evaluate harmonic inter-

actions during filter design:

$$\text{MIIF}_{e,n}(h) = \frac{V_{e,h}}{V_{n,h}}, \quad h \in \{2, 3, \dots\}, \quad (2.9)$$

where a small harmonic current of order h is injected at the *new* converter bus n , the resulting harmonic voltages $V_{n,h}$ and $V_{e,h}$ are measured at buses n and e , and the ratio is formed exactly as for the fundamental case. Because network impedances are highly frequency-dependent, $\text{MIIF}_{e,n}(h)$ can exceed 1.0; such values flag amplification caused by parallel/series resonances and therefore guide the sizing and tuning of AC filters at the new station.

Practical guideline of Harmonic MIIF Parametric studies in [39] suggest a threshold of $\text{MIIF} < 0.1$ to declare negligible harmonic coupling; larger values warrant iterative filter coordination with the existing HVDC links. The method is most useful during early planning when only a few critical harmonics (e.g. characteristic $(6n \pm 1)$ orders) need to be checked.

Limitations of Harmonic MIIF:

- Each harmonic order requires a separate EMT run (or field test), so a full sweep across 2–2 kHz becomes time-consuming when many network configurations must be screened [40].
- The procedure captures *network* impedance effects but still neglects dynamic controller reactions, which are increasingly important for VSC-based devices whose P – Q coupling differs markedly from that of LCC links [31].
- Because the approach is based on current injection, it offers little physical insight into why a particular resonance appears; impedance-scan techniques (treated in the next

subsection) remedy this by displaying the frequency-dependent admittance directly [41].

ii) Impedance–Scan Interaction Factors The harmonic–injection extension of the MIIF pinpoints critical frequencies, but it still requires one EMT run *per* harmonic order. A single wide-band *frequency scan* of the network impedance provides a far more economical data set from which interaction indices can be derived. Two frequency-domain metrics—the *Radiality Factor* (RF) and the *Modified Impedance-Equivalent MIIF* (MIEIF)—are summarised below; both extract their values from the same $Z(f)$ (or $Y(f)$) matrix and therefore capture the entire spectrum in one sweep.

ii-1) Radiality Factor (RF) — Impedance–Scan Screen [31, 41] Starting from the reduced 2×2 impedance matrix that links two candidate devices (converter–converter, converter–machine, etc.), the *radiality factor* at frequency f is computed as

$$\text{RF}(f) = \frac{|Z_{ii}(f)|}{|Z_{ii}(f)| + |Z_{ij}(f)|}, \quad 0 \leq \text{RF} \leq 1.$$

Large values imply that the buses are electrically “radial”—and thus strongly coupled—whereas values near zero indicate a long electrical distance. Tests in [41] showed that, in the subsynchronous range, $\text{RF} \geq 0.2$ consistently captured all unstable or marginally stable shaft–converter interactions, making 0.2 a practical (though not universal) screening threshold.

Limitations of RF :

- *Pair-wise only*: the formulation evaluates *two* dynamic devices at a time and assumes that the remainder of the system does not react to the resulting subsynchronous power

exchange [31].

- *Screening, not proof*: because a single numerical threshold cannot perfectly separate stable from unstable cases, RF may raise *false alarms*. This is intentional: the method is designed to guarantee zero *false dismissals*, after which the flagged scenarios are passed to detailed EMT studies for confirmation [41].

ii-2)Multi-infeed Energy Interaction Factor (MIEIF) [40] generalise the classical MIIF by combining the voltage-amplification term with the actual harmonic current that flows between the two buses:

$$\text{MIEIF}(f) = \left| \frac{V_{\text{out}}(f)}{V_{\text{in}}(f)} \right| \times \left| \frac{I_{\text{out}}(f)}{I_{\text{in}}(f)} \right| = \left| \frac{Z_{\text{out}}(f)}{Z_{\text{in}}(f) + Z_{\text{io}}(f)} \right| \times \left| \frac{Z_{\text{in}}(f)}{Z_{\text{in}}(f) + Z_{\text{io}}(f) + Z_{\text{out}}(f)} \right| \quad (2.10)$$

- $V_{\text{in}}(\mathbf{f})$ represents the input bus voltage at harmonic frequency $\mathbf{f}$, where the harmonic source is injected.
- $V_{\text{out}}(\mathbf{f})$ is the resulting voltage observed at the output bus.
- $I_{\text{in}}(\mathbf{f})$ and $I_{\text{out}}(\mathbf{f})$ denote the harmonic currents at the input and output buses, respectively.
- $Z_{\text{out}}(\mathbf{f})$ is the impedance seen by the output bus.
- $Z_{\text{in}}(\mathbf{f})$ is the input network's impedance as seen from the harmonic injection point.
- $Z_{\text{io}}(\mathbf{f})$ represents the mutual impedance between the input and output buses.

A single network-impedance sweep 10–3000 Hz in [40] yields the entire $\text{MIEIF}(f)$ curve, which has been shown to reproduce, within a few percent, the harmonic-injection results yet at a fraction of the computational cost. Frequencies where $\text{MIEIF} > 0.1$ correlate closely with sizeable cross-bus harmonic distortion and therefore guide the filter-design stage more effectively than the voltage-ratio-only MIIF . The trade-off, as with any small-signal scan, is that control non-linearities and saturation under severe faults remain outside the model scope.

Nonfundamental Frequency Interaction Summary:

- *Harmonic-Injection MIIF* gives an intuitive, controller-agnostic voltage-amplification metric but requires one EMT run per harmonic order.
- *Impedance-scan metrics* (RF for electrical proximity and MIEIF for rating-weighted amplification) condense the entire 10–3000 Hz band into a single frequency sweep, offering a rapid triage that invariably captures all cases flagged by the injection method.

2.1.4 Simulation-Derived Disturbance Indices

The previous subsections relied primarily on *analytical* or *quasi-static* constructs—SCR families, MIIF variants, CPI formulations—to obtain rapid, first-pass assessments of multi-infeed HVDC performance. In practice, however, the ultimate design limits of an AC/DC grid are set by large-signal phenomena that unfold only when the full, non-linear dynamics of converters, synchronous machines, protection devices, and network impedances are represented in the time domain. Planners therefore complement analytical screens with a second tier of *simulation-derived indices*: scalar metrics distilled directly from electromagnetic-transient (EMT) or phasor-domain fault studies.

This section reviews the four disturbance-oriented index families most widely adopted in HVDC and inverter-rich power systems:

- (a) **Commutation-Failure Immunity Index (CFII)** for LCC links,
- (b) **Critical-Clearing Time (CCT)** for transient-angle stability,
- (c) **Voltage-related indices**—Transient Over-Voltage (TOV) for LCCs and Voltage-Ride-Through (VRT) envelopes for VSCs,
- (d) **Frequency-stability indices**—Rate of Change of Frequency (RoCoF) and frequency nadir.

2.1.4.1 Commutation-Failure Immunity Indices for Line-Commutated Converters

Commutation failure (**CF**) remains the dominant short-term dynamic limitation for conventional line-commutated converter (LCC) high-voltage direct-current (HVDC) schemes. A quantitative index that captures the minimum converter AC voltage reduction required to avoid CF, while remaining simple enough for planning studies, is therefore indispensable. This section reviews the development of such indices, highlights their inherent assumptions, and summarizes the most recent refinements that extend the concept to multi-infeed networks.

Classical quasi-steady-state criterion [42] The earliest approach linearises the converter equations around the pre-fault operating point and derives the threshold AC voltage drop $\Delta V_{\min}$ that triggers commutation failure during a balanced three-phase fault:

$$\Delta V_{\min} = 1 - \frac{I_{d,\text{psf}}}{I_{d,\text{pre}}} \cdot \frac{I_{\%} X_c}{I_{\%} X_c + \cos \gamma_0 - \cos \gamma} \quad (2.11)$$

where $I_{d,\text{pre}}$ and $I_{d,\text{psf}}$ are the pre- and post-fault DC currents, $I_{\%} = I_{d,\text{pre}}/I_{d,N}$ is the per-unit loading with respect to the nominal current $I_{d,N}$, X_c is the per-unit transformer leakage reactance, γ is the extinction-angle set-point, and γ_0 ($\approx 5^\circ$ – 9°) is the critical extinction margin of the valve. If the actual voltage depression exceeds $\Delta V_{\min}$, a commutation failure is expected. Subsequent experience showed that (2.11) is *conservative*, primarily because it neglects transient firing-angle dynamics and the phase shift of the AC voltage during the fault.

Electromagnetic transient (EMT)–based Commutation-Failure Immunity Index (CFII) [10]: To overcome the shortcomings of the quasi-steady approximation, [10] replaced the analytical solution with an EMT-determined *critical fault level* and defined the *Commutation-Failure Immunity Index* as

$$\text{CFII} = \frac{S_{\text{crit}}}{P_{\text{dc}}} = \frac{V_{\text{ac}}^2}{\omega L_{\min} P_{\text{dc}}} \times 100 \quad (2.12)$$

where S_{crit} is the product of the pre-fault bus voltage and the fault current that *just* induces CF, P_{dc} is the rated DC power, and $L_{\min}$ is the *minimum* reactive fault inductance that still avoids CF for the specified converter parameters. Because (2.12) is anchored in time-domain EMT simulations, it implicitly captures phase-angle shifts, higher-order harmonics, and control-system dynamics.

Sensitivity to fault type: Systematic EMT sweeps revealed that CFII is lowest (i.e. immunity is worst) for *inductive* faults, followed by *resistive* and *capacitive* faults. With respect

to network topology, three-phase-to-ground faults had long been assumed to be the most severe. A recent study [11], however, demonstrated that *unsymmetrical double-phase* faults can produce an even smaller CFII compared to the three-phase fault proposed in [10] due to a much larger zero crossing voltage phase shift from the double-phase fault. Consequently, the double-phase inductive case is now recommended to conduct CFII assessments.

Extension to multi-infeed LCC systems: When several inverters share a weak AC system, the **Local** CFII (LCFII) and **Concurrent** CFII (CCFII) distinguish between faults that provoke commutation failure only at the local terminal and those that propagate to remote inverters, respectively [6]. In this context $L_{\min}$ in Eq. (2.12) is re-interpreted as the smallest network inductance that prevents the *specific* CF mode under study. Concurrent immunity exhibits an inverse correlation with the Multi-Infeed Interaction Factor (MIIF): higher electrical coupling (larger MIIF) lowers CCFII, whereas LCFII remains mainly governed by the local short-circuit ratio (SCR).

Applications and advantages: Because CFII is derived from time-domain EMT simulations, it inherently captures voltage-phase shifts, harmonic distortion, and control-system dynamics that analytical criteria neglect. The same framework scales to multi-infeed networks through LCFII and CCFII, providing planners with an objective measure of each inverter’s vulnerability and a quantitative metric for comparing alternative transformer designs, firing-angle margins, and network-strength upgrades.

Limitations and practical considerations: CFII applies exclusively to LCC inverter stations; voltage-sourced converters (VSCs) do not experience commutation failures, so the index cannot be used to benchmark the portfolios with VSC-type HVDC. Estimating the

minimum fault inductance $L_{\min}$ also requires extensive EMT sweeps across fault impedances, inception angles (points-on-wave) and all the inverter stations in the system, making the process computationally intensive for large systems. A pragmatic workflow, therefore, would be recommended; the approach can couple coarse screening (e.g., corrected $\Delta V_{\min}$) with targeted EMT batches, focusing on the worst-case double-phase inductive faults only for reducing the computation and simulation burden [43, 44].

2.1.4.2 Critical-Clearing Time (CCT)

Concept and Classical Definition: For a disturbance to be deemed *transiently* tolerable, it must be cleared before the rotor angle of any synchronous machine reaches its *critical clearing angle*; the associated duration is the **critical-clearing time** (CCT). Formally, CCT is “the maximum permissible fault duration after which the subsequent system response remains stable” [45]. Traditionally the index is obtained by a bisection (or binary) search that iteratively lengthens the fault until the machine enters out-of-step [46]. Because each iteration evaluates a full EMT or phasor simulation, the search is computationally intensive yet remains a benchmark for ranking contingency *severity* [47].

Converter-Aware Ride-Through CCT: Conventional CCT ignores the physical limitations of power-electronic devices. To close that gap [48] proposed a *ride-through-constrained CCT* that enforces, in addition to rotor-angle stability, compliance with the transient voltage envelope required by modern renewable-energy converters:

- If the converter-terminal voltage strays outside the prescribed *voltage-ride-through* (VRT) envelope—covering both low- and high-voltage tolerances—and remains there longer than the device’s current or dc-link ratings allow, the fault is judged to have

exceeded the CCT criterion, even though the synchronous machines alone could still re-synchronise.

- Enforcing this combined VRT-CCT limit also safeguards the equipment itself: for full-scale wind turbines it prevents rotor over-speed and dc-link over-voltage, while for PV inverters it avoids damaging dc-link stress during deep or prolonged voltage excursions.

The resulting “VRT-CCT” is therefore more restrictive than the classical angle-based CCT and better represents mixed synchronous/IBR systems.

Empirical Insights from Recent Studies:

- Renewable-penetration impact:* Multiple case studies [48, 49] show a monotonic *decrease* of CCT as inverter-based generation displaces the synchronous machine’s inertia. Despite fast current control, strict overcurrent limits curtail the fault ride-through capability of IBRs, lowering the overall transient stability margin.
- Control-mode comparison for VSC links:* Operating a VSC-HVDC terminal in *AC-voltage* control extends CCT relative to reactive-power control because fast voltage support improves post-fault electrical torque on nearby machines [50].

Limitations and Practical Considerations:

- **Search burden in large grids:** In a multi-infeed HVDC corridor each rectifier/inverter fault requires an independent CCT search. With hundreds of contingencies the cumulative EMT runtime becomes prohibitive.
- **Protection–setting discrepancy:** The *critical clearing time* obtained from an EMT-based sensitivity sweep represents an *upper* stability bound on a benchmark test net-

work. In real transmission grids, relay and breaker clearing times are set deliberately *below* this threshold—often by a wide security margin—to accommodate relay time-dial tolerances, breaker arcing time and communication delays. Consequently, CCT values serve primarily as a stability *margin indicator* for planners, not as a figure that can be transferred one-to-one into protection settings [45].

- **Symmetry bias in the fault set:** Classical CCT studies almost always assume a solid three-phase-to-ground fault, because it yields the most severe rotor-angle acceleration in synchronous machines. In reality, high-impedance, single-line-to-ground or phase-to-phase faults occur far more frequently and leave a non-zero unbalanced post-fault voltage. To cover these asymmetrical contingencies a much larger EMT ensemble—each with its own iterative search—is required, which can increase simulation time by an order of magnitude [51].
- **Evolving behaviour with inverter-based resources (IBRs):** Modern grids with large fractions of wind, PV and electronic loads depart from the static machine/load mix assumed in the swing-equation era. Converter-interfaced generators exhibit strict current limits and fast control actions; electronic loads can change their effective impedance in milliseconds. Both factors shorten the true stability window and make a single CCT number—derived from a fixed network and load snapshot—less representative of real-time conditions under high IBR penetration [52, 53].

CCT remains a valuable benchmark for gauging transient-stability headroom, it must be interpreted with caution and complemented by the extended contingency sets—especially in converter-rich, dynamically varying power systems.

2.1.4.3 Voltage-Related Indices for HVDC Planning

Voltage excursions after converter or network disturbances fall into two conceptually different categories: (i) **transient over-voltages (TOVs)** that arise mainly in *LCC*-dominated links when reactive-power balance is suddenly lost, and (ii) **voltage-ride-through (VRT) envelopes** that specify the **VSC**-based equipment's survival limits in terms of *magnitude* and *duration*. This subsection reviews the indices, analytical tools and design standards that quantify both phenomena, and explains how they are used in the multi-infeed screening workflow adopted later in the thesis.

A. Transient Over-Voltage (TOV) in Line-Commutated Links When a line-commutated inverter operates on a weak AC system, any rapid loss of DC power—for example a *bipole block*, an *AC bus fault* or a *DC pole fault*—eliminates the converter's reactive-power demand while the local filters and shunt capacitors remain energised. The resulting mismatch produces a fundamental-frequency over-voltage that is often reinforced by low-order harmonic components [6, 12]. Because equipment insulation, surge arresters and customer loads are sensitive to these peaks, LCC HVDC specifications impose strict TOV design limits, especially at very low ESCR inverter sites.

1) Two common study approaches.

- (a) *Bipole blocking test*—All HVDC system are forced to be out of service at full load; the ensuing Mvar rejection at the inverter bus yields the worst over-voltage for most systems [6, 8].
- (b) *AC-fault driven TOV*—A severe fault causes inverter commutation failures; after clearing, the converter current recovers slowly while all filters are still connected, also gen-

erating a over-voltage on the inverter bus but often be smaller than blocking all the HVDC systems at one time. [9].

2) Analytical correlation with system strength. For screening purposes [8] derived an approximate relationship between the peak TOV and the system strength index (ESCR for single-infeed or MIESCR for multi-infeed):

$$\text{TOV}_i = \sqrt{\frac{a}{\text{MIESCR}} + \sqrt{1 - \frac{1}{a^2} + a^2}}, \quad a = \sqrt{1 + k^2}, \quad k = \frac{Q_{ac}}{P_{dc}} = \tan\left[\arccos\left(\cos\alpha - \frac{X_c}{2}I_d\right)\right]. \quad (2.13)$$

Here k encapsulates the operating point through the firing angle α , and DC current I_d . X_c represents the converter reactance. Equation (2.13) confirms the intuitive trend observed in EMT studies: *stronger* systems (larger ESCR/MIESCR) exhibit *lower* transient over-voltage peaks.

3) Limitation of TOV analytical solution: The closed-form model neglects transformer saturation, resonant interactions and higher-frequency components; measured TOVs can therefore exceed the theoretical value by several percent [8,14]. Best practice is to apply Eq. (2.13) as a rapid *screen*; cases that approach the specified limit are then validated by detailed EMT blocking and AC-fault runs.

B. Voltage-Ride-Through (VRT) Envelopes for VSC Systems Modern VSC stations—and the renewable plants they often connect—must *stay connected* through voltage depressions *and* over-voltages imposed by grid codes. North-American requirements are codified in NERC PRC-024/PRC-029 [54, 55], while Manitoba Hydro’s *Transmission System Interconnection Requirements* (TSIR) refine those limits for very weak prairie systems [56].

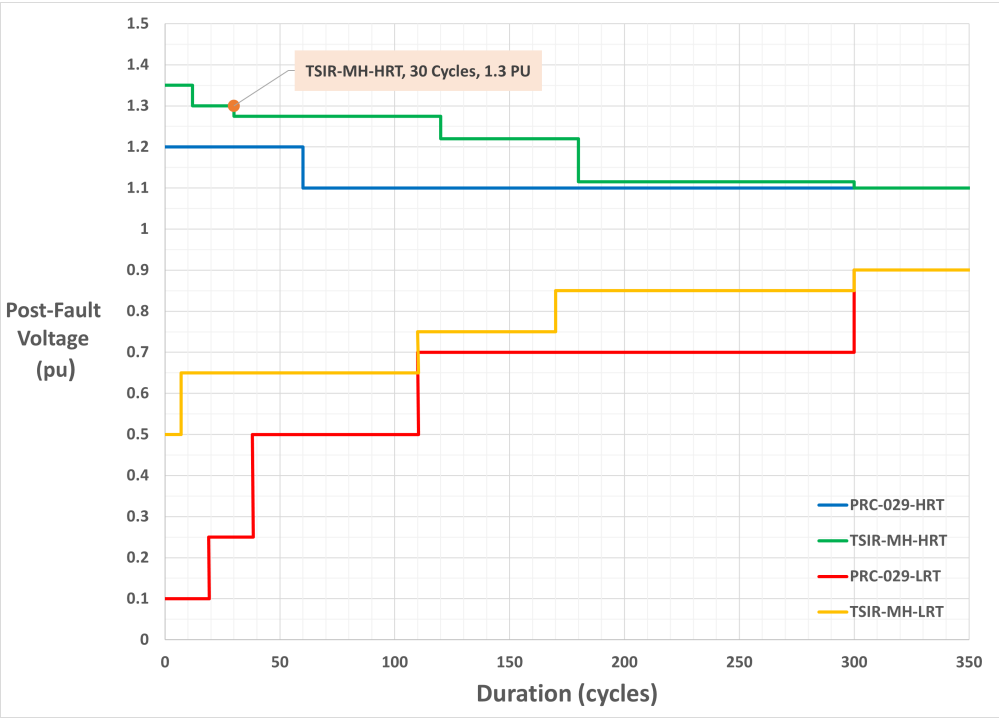


Figure 2.2: High- and low-voltage ride-through envelopes in NERC PRC-029 (red / blue) and Manitoba Hydro TSIR (orange/ blue). The marker highlights an example of permitted 1.3 pu/12-cycle high-voltage excursion.

Figure 2.2 illustrates the composite “magnitude” plus “duration” nature of these envelopes. For instance, a post-fault peak of 1.30 pu is *acceptable* provided it subsides within 30 cycles (orange marker). Hence a meaningful *voltage index* must couple amplitude and time—the feature delivered by the CPI-based method proposed in this thesis. Although the CPI-based method does not directly indicate discrete violations of standardized VRT envelopes, its formulation as an integrated error over time ensures that the resulting value inherently reflects both the magnitude of the deviation and the duration for which it persists.

VRT Index interpretation: If a simulated voltage–time point lies *outside* the prescribed polygon, the event is deemed a ride-through violation; if it remains inside, the converter survives without tripping.

HVDC Voltage-Related Indices Summary:

- **TOV indices** (analytical plus EMT) remain essential for LCC inverters; their peak value scales inversely with ESCR/MIESCR and must respect equipment insulation limits [6].
- **VRT envelopes** define a “no-trip” region for VSC stations and renewable DERs; compliance demands joint magnitude–duration assessment rather than a single voltage number [54, 55, 57].
- **CPI synergy:** Because CPIs integrate *both* error magnitude and persistence, they offer a natural bridge between the TOV peak criterion and the time-stair-case ride-through rules, enabling unified comparison of mixed LCC/VSC scenarios in subsequent chapters.

2.1.4.4 Frequency–Stability Indices

The frequency of a synchronous area is an immediate barometer of the generation–load balance. As conventional inertia is displaced by fast–acting converter resources (HVDC, wind, PV, batteries), planners increasingly rely on *quantitative indices* to judge whether the system can survive the first few seconds after a large disturbance. Two complementary metrics are widely used:

- **Frequency Nadir** – records the *deepest* frequency dip before primary response reverses the decline.
- **Rate of Change of Frequency (RoCoF)** – captures the *initial* acceleration of the frequency trajectory.

1) Definition and Conceptual expression

A. Frequency Nadir The *frequency nadir*, f_{nadir} , is the lowest instantaneous frequency reached during an under-frequency transient, typically after a sudden generation loss or imbalance. It marks the point where decline halts and recovery begins, driven by inertia and primary frequency response (governor action, batteries/fast reserves, etc.) [15]. Unlike RoCoF, which can be approximated analytically in the first few hundred milliseconds, the nadir reflects the *integrated* action of disturbance size, inertia, load damping, and the magnitude/speed of primary response [16]. Approximate calculations can be made using system frequency response (SFR) models; e.g., with linear governors and uniform response speed, one can formalize a frequency-nadir index (FNI) that links nadir to inertia and control characteristics [17]. In advanced frameworks, the nadir is even expressed as an analytic func-

tion of controllable resources—such as HVDC modulation and demand response—enabling coordinated tuning for nadir mitigation in a real-time operation platform [58].

B. Rate of Change of Frequency (RoCoF) RoCoF is the first derivative of the system frequency:

$$\text{RoCoF}(t) = \frac{df(t)}{dt} \quad [\text{Hz/s}].$$

Immediately after a generation–load imbalance ΔP_{imb} the swing equation gives an approximate “opening-slope” value

$$\text{RoCoF}|_{t=0+} \approx -\frac{\Delta P_{\text{imb}}}{2H P_{\text{base}}} f_0, \quad (2.14)$$

where H is the equivalent inertia constant, P_{base} the MVA base and f_0 the nominal frequency. Equation (2.14) highlights the inverse relationship between inertia and initial RoCoF magnitude.

2) Practical Operational utilisation

- *Protection and islanding detection*—Many protective relays use RoCoF and f_{nadir} to detect islanding (loss of mains) or severe events; distributed generation may trip if thresholds are exceeded. Modern grid codes require generators and IBRs to ride through high-RoCoF events; guidelines mandate withstanding at least ± 5 Hz/s [55, 59].
- *Dynamic under-frequency load shedding (UFLS)* – adaptive schemes trigger earlier and shed more load when a high RoCoF or low f_{nadir} occurs, some load can be shed preemptively before the frequency collapses to critical threshold. This fast action can prevent the frequency nadir from falling into a dangerous zone [60].

- *Real-time inertia monitoring* – operators back-calculate an “apparent inertia” from measured RoCoF and event size; if the value falls below a predefined floor, fast frequency reserves are armed [61].

3) Known limitations of RoCof

- **Measurement sensitivity:** Window length and filtering strongly affect df/dt ; inconsistent settings can lead to an order-of-magnitude spread in reported values for the same event [60]. PMUs often fail to reject narrowband disturbances such as harmonics and interharmonics outside the fundamental passband. These disturbances cause spectral leakage and bias in the estimated RoCoF values. [62]. Harmonised signal-processing standards are now being proposed [63].
- **Spatial variation:** “System” frequency is not perfectly uniform during the first swing; buses electrically remote from inertia sources may record higher RoCoF and high frequency excursion, challenging the use of a single universal threshold in large areas. To address this issue, the costly implementation of a Wide Area Monitoring System (WAMS) is required [64, 65].
- **Limited diagnostic scope:** Neither RoCoF nor frequency nadir alone provides a complete picture of system frequency dynamics. While RoCoF captures the initial rate of frequency decline, it offers no insight into the eventual nadir, frequency overshoot, or steady-state restoration. Conversely, frequency nadir reflects the worst point of frequency deviation but not the speed or severity of the initial drop. These indices are therefore best interpreted in conjunction. For instance, a low-inertia system with poor RoCoF performance may still maintain stability if fast-acting reserves are sufficient;

meanwhile, a high-inertia system with inadequate primary frequency response could still suffer collapse. As such, comprehensive frequency security assessment must integrate RoCoF, nadir, and additional recovery metrics to ensure robust conclusions [9].

2.1.5 Limitations of Existing Planning Indices

Synthesizing the preceding review, the main limitations cluster by index family as follows:

System Strength Indices: SCR-based measures quantify the Thévenin stiffness available at a converter’s point of common coupling by comparing short-circuit level to converter rating, and they remain widely used as first-pass screens in planning studies [18]. Several variants extend the basic idea to account for practical features or MIDC contexts, including the ESCR for LCC installations [19], CSCR [21], WSCR [23], and AISCR [25, 28] to reflect perceived strengthening due to controls or compensation. However, these indices are ultimately single-number proxies derived from a static fundamental-frequency snapshot; they do not describe the post-fault recovery, nor the frequency-dependent behavior of modern converter controls whose effective impedances vary with bandwidth, operating point, and network resonances.

Quasi-Static Margin Indices: Quasi-static techniques evaluate an AC/DC network via a sequence of steady states, thereby bypassing detailed electromechanical and electromagnetic dynamics while enabling rapid exploration of operating conditions and equipment parameters. The classical indices are —the MAP [12], the VSF [13, 14], and the CSI [34]—each translating nonlinear P – V – Q relationships into compact scalars for screening. Their appeal as analytical solution tools capable of rapidly assessing different system conditions, and they are effective for locating the static boundary of voltage or power stability. However,

as the operating point approaches that instability boundary (e.g. P - V nose point), most load-flow or continuation algorithms experience Jacobian singularities and fail to converge, making it difficult to locate the exact static instability [19]. Moreover, because these indices are intrinsically static, they omit closed-loop converter and network dynamics and therefore cannot characterize post-fault waveform quality and must therefore be cross-checked with time-domain studies [33].

Interaction Indices: Interaction indices characterize how converters influence one another—and nearby synchronous machines—through shared AC pathways. At the fundamental frequency, converter–converter coupling is commonly screened with MIIF [6] and its variants, such as WMIIF [7] and the MVIF [30], which use impedance-based sensitivities to quantify voltage amplification between terminals. Converter–machine coupling is often assessed by UIF [36], a simplified metric for identifying potentially resonant converter–generator pairs. Beyond 50/60 Hz, non-fundamental interaction studies extend screening into subsynchronous and harmonic regimes using tools such as harmonic-injection MIIF [39], the RF [41], and the MIEIF [40]. These indices often rely on empirical thresholds or screening cut-offs (e.g., $\text{MIIF} < 0.1$, $\text{RF} < 0.2$) that are drawn from specific case studies and can misclassify risk outside those contexts [31]. They are also not comprehensive: each metric isolates a single interaction pathway (converter–converter, converter–generator, or converter–network) [20].

Simulation-Derived Indices: Simulation-based disturbance metrics—such as the CFII [10, 11, 43], CCT [45, 48, 50], TOV [8, 9], and frequency-related measures [15–17] like RoCoF and frequency nadir—remain the highest-fidelity screening tools because they are extracted from EMT or phasor-domain simulations that embed control actions, protection logic, and network dynamics. Despite this fidelity, their planning value is constrained by *fragmented scope*:

each index targets a single phenomenon (e.g., CFII/TOV for voltage stress, CCT for synchronism, RoCoF/nadir for inertia), leaving engineers to reconcile multiple indicators; no unified scalar spans voltage–frequency behaviors for option ranking. Many metrics focus solely on peak or minimum values and ignore *how long* an excursion persists, even though duration is crucial for protection clearing times and equipment thermal limits. A resilience metric should therefore penalize both *magnitude* and *persistence* of post-fault deviations (e.g. fault-ride-through compliance) [55, 59].

In summary, these limitations discussed above motivate a controller-aware, time-domain summary that compresses rich waveforms into consistent, system-level scores.

2.2 The Proposed Method: Control Performance Indices (CPI) Evaluation Method

This section presents the theoretical foundation and practical application of *control performance indices (CPIs)* for evaluating multi-infeed HVDC systems. It begins with the theoretical background of Control Performance Indices (CPI), including their origins in classical control theory and relevance to transient-stability assessment. The main indices are defined through a common functional form, with their practical significance summarised. The detailed applications of CPI follow in Section 2.3, in this thesis they are used to quantify post-fault transients in multi-infeed HVDC.

2.2.1 Fundamental Theory Behind Control Performance Indices

CPIs are quantitative metrics from classical control theory that assess how well a feedback system's output $y(t)$ tracks a prescribed reference $y_{\text{ref}}(t)$. The tracking error is

$$e(t) = y_{\text{ref}}(t) - y(t).$$

A CPI is a scalar functional $\mathcal{CPI}[e(t)]$ that maps the entire error trajectory to a single performance score. In this thesis, the integration horizon T is chosen long enough to capture post-fault transients (typically 5–10 s in EMT simulations). A generic form is

$$\boxed{\mathcal{CPI} = \int_0^T w(t) g(e(t)) dt} \quad (2.15)$$

where (i) $g(\cdot)$ penalises the error magnitude (e.g., absolute value or squared value), and (ii) $w(t)$ is a non-negative weighting function that shapes the relative importance of early versus late errors.

Standard choices recovered from (2.15) include the *integral square error (ISE)*, *integral absolute error (IAE)*, *integral time-weighted absolute error (ITAE)*, and *integral time-weighted square error (ITSE)* [66,67].

The appropriate CPI depends on the performance objective (minimising overshoot, reducing oscillations, accelerating settling, etc.). Starting from Equation (2.15), four canonical indices are recovered by selecting g and w as summarised in Table 2.1.

Penalty logic of each CPI is briefly explained in Table 2.1, the four CPIs prioritise different behaviours of the error trajectory: IAE treat all deviations uniformly, yielding a balanced measure of total accumulated error, ITAE accentuates lingering errors and thus

Table 2.1: Comparison of standard CPIs (from (2.15))

Index	$g(e)$	$w(t)$	Emphasises (penalty logic)
ISE	e^2	1	Large spikes (quadratic)
IAE	$ e $	1	Total deviation (absolute)
ITAE	$ e $	t	Lingering error (time-weighted $ e $)
ITSE	e^2	t	Peaks & duration (time-weighted e^2)

promotes fast settling, ITSE emphasises both magnitude and persistence via a time-weighted quadratic penalty, and ISE’s quadratic form strongly amplifies large peaks, hence effective for detecting violent oscillations or controller instability—consistent with the security-oriented screening required in this study. Accordingly, ISE is adopted as the primary metric; its explicit formulation and justification are presented next.

2.2.2 Justification for Selecting ISE as the Main CPI

The *integral square error (ISE)* is

$$\text{ISE} = \int_0^T e^2(t) dt. \quad (2.16)$$

The present work concentrates on *very-fast* phenomena that unfold in the first few seconds after a severe disturbance in a multi-infeed HVDC grid. Because the goal is to score—and to compare—those short-lived excursions, we adopt the **Integral Square Error (ISE)** as our principal Control-Performance Index. Four arguments motivate this choice.

- i) **High sensitivity to large excursions:** ISE accentuates large deviations via its quadratic penalty on error. Voltage or frequency spikes that approach limits dominate the score, aligning with security-oriented studies where any brief violation must be

revealed. In contrast, time-weighted indices (ITAE/ITSE) multiply the error by t , de-emphasising early spikes. These are effective for long-horizon tuning, but less so when the first 1–2sec are of principal interest.

- ii) **Rapid convergence:** Figure 2.3 shows frequency and cumulative CPI traces for two HVDC configurations: MMC–MMC (blue) and mixed LCC–MMC (green). Among the indices evaluated, ISE settles first, providing an immediate indication of stabilisation. ITAE continues to grow due to its time weighting, and IAE may continue to accumulate whenever a residual absolute error persists, making both less effective for short-duration post-fault dynamics.
- iii) **Clear visual discrimination:** Because ISE is dominated by the severe initial excursion, the blue and green traces in Fig. 2.3 (fourth panel) separate cleanly: the mixed link yields $ISE \approx 0.72$, whereas the MMC link remains near $ISE \approx 0.48$. By comparison, the ITAE/ITSE curves are nearly indistinguishable in the first second, obscuring the performance gap of interest.
- iv) **Correlation with key transient metrics:** Table 2.2 compares CPI values with classical dynamic figures of merit. ISE correlates with minimum frequency, peak overshoot, and recovery time, whereas ITAE shows little monotonic relation to those critical quantities. ISE is therefore better suited for studies aimed at transient-performance assessment.

In summary, ISE satisfies three practical requirements of this thesis: (i) sensitivity to critical peak excursions, (ii) fast convergence for automated EMT sweeps, and (iii) robust differentiation between competing HVDC architectures. The remaining CPIs (IAE, ITAE,

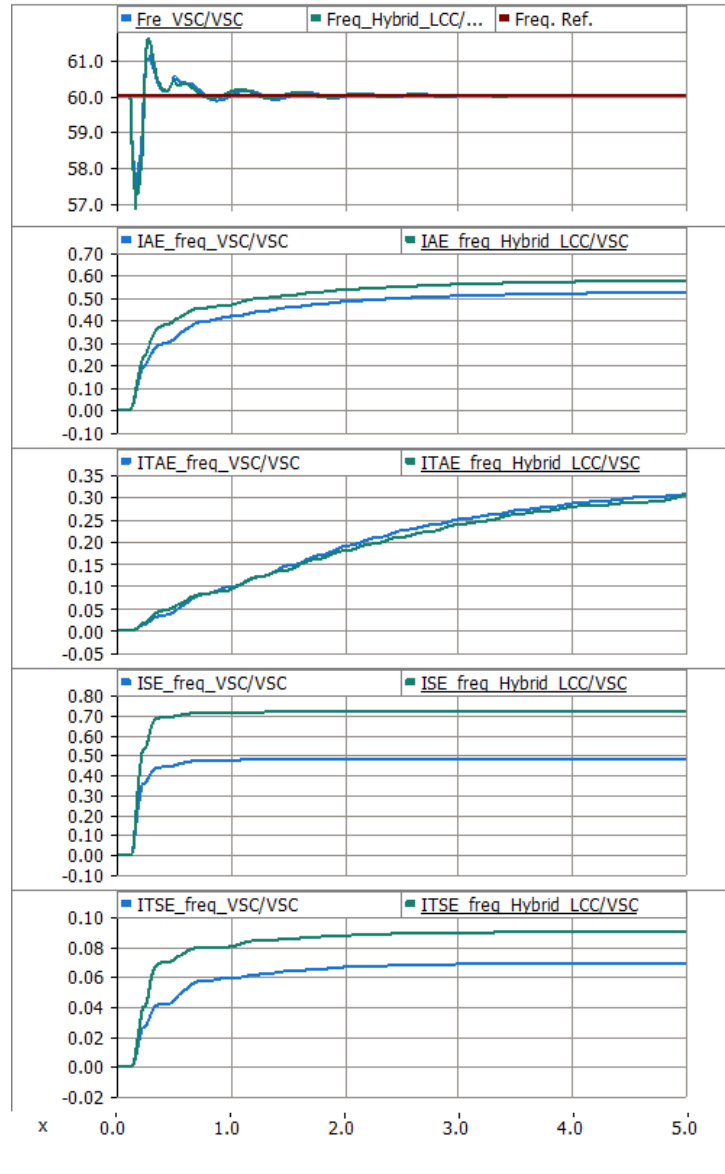


Figure 2.3: Post-fault frequency and cumulative CPIs of two HVDC topologies.

Table 2.2: Comparison of CPI values and key dynamic metrics

Topology	CPI value		Frequency response (Hz)			Recov. time (s)
	ITAE	ISE	$f_{\min}$	$f_{\max}$	f_{set}	
MMC–MMC	0.299	0.482	57.5	61.0	60.0	0.22
LCC–MMC (Mixed)	0.300	0.719	56.8	61.5	60.0	0.23

ITSE) are still computed and archived for completeness, but comparative statements in the next chapters default to *ISE* unless noted otherwise.

2.3 Application of CPI Reported in Literature

Having established the theoretical foundations and our CPI-based evaluation workflow in the preceding section, we now position that framework within the wider body of published work. The literature includes studies that embed integral-error indices within optimisation loops, employ them as dynamic-stability metrics, or extend the same concepts to non-power-system domains. The review is organised into three parts: (i) CPI-driven optimisation of HVDC controller parameters; (ii) CPI applications to network-wide dynamic-stability evaluation; and (iii) broader, cross-disciplinary uses of control-performance indices. Each subsection highlights key methodologies, findings, and limitations that inform our proposed approach.

2.3.1 CPI-Driven HVDC Controller Optimisation

Early work [68] demonstrated that a classical control-performance index—the integral square error (ISE)—can be embedded directly within a nonlinear optimisation loop that drives an electromagnetic-transient (EMT) simulation. In their framework, PSCAD/EMTDC

evaluates

$$\text{ISE} = \int_0^{T_w} [I_{\text{ref}}(t) - I_d(t)]^2 dt, \quad (2.17)$$

where T_w is the evaluation window, $I_{\text{ref}}(t)$ the commanded dc current, and $I_d(t)$ the measured dc current. The Nelder–Mead simplex algorithm proposes new controller gains, launches a fresh EMT run, and iterates until the ISE is minimised. Within several dozen iterations, the gains for an LCC link converged to settings that yielded faster current recovery and reduced overshoot compared with manual tuning [68].

Robust design across grid strengths: [69] extended the idea by evaluating several EMT runs per iteration and aggregating their partial CPIs into a weighted objective [69]:

$$\text{CPI}_{\text{agg}} = \sum_{k=1}^N w_k \text{CPI}_k, \quad (2.18)$$

where each run k represents a distinct short-circuit ratio ($\text{SCR} = 2, 3, 5$). Weights $(w_1, w_2, w_3) = (1, 1, 0.5)$ emphasised weak and medium grids without over-constraining the strong-grid case, yielding one gain set that performed well across the full operating envelope.

Time-varying weights for fault recovery: Building on this concept, [70] introduced a time-dependent weighting and a penalty term to privilege post-fault recovery while tempering aggressive current tracking:

$$\text{CPI}(X) = \int_0^{T_w} w(t) [I_d(t) - I_{\text{ref}}(t)]^2 dt + F(t), \quad (2.19)$$

with $w(t)$ chosen elevated in the post-fault window and low elsewhere, and $F(t)$ penalising rapid dI_d/dt that could precipitate commutation failure. A two-stage routine—first

tuning for set-point changes, then refining the voltage-dependent current-limit (VDCL) loop—reduced fault-recovery time while maintaining robustness for $SCR = 1.9\text{--}3.0$ [70].

CPI Based HVDC Design summary

- i) *Objective formulation:* choose a CPI (typically ISE) that reflects the most critical waveform; it becomes the optimisation cost.
- ii) *Robustness by aggregation:* combine partial CPIs from a range of scenarios using scenario-specific weights.
- iii) *Refine with Time-varying Weights and Penalties* Boost the weight after fault clearing and add penalty terms to tame rapid current changes or avoid commutation failure for HVDC LCC Design.
- iv) *Staged tuning:* optimise the main loops first, then re-optimize auxiliary functions (e.g. VDCL) for exceptional events such as severe faults.

These studies collectively demonstrate how CPIs—especially the high-sensitivity *ISE*—can move beyond passive assessment tools and serve as active, optimisation-friendly cost functions for the automatic synthesis of robust HVDC control systems.

2.3.2 Applications of CPIs in Dynamic Stability and Performance Evaluation

Several studies on *control-performance indices* showed that the same family of quadratic-error measures that we use for HVDC design can be extended—almost without modification—to judge *network-wide* dynamic behaviour and to guide discrete or continuous control actions after large disturbances.

ISGA: an ISE analogue for multi-machine systems. [71] introduced the *integral-square generator-angle (ISGA)* index to measure inter-machine desynchronisation:

$$\text{ISGA}(t) = \int_0^t \sum_{i=1}^N M_i [\theta_i(\tau) - \theta_{\text{COA}}(\tau)]^2 d\tau, \quad \theta_{\text{COA}} = \frac{\sum_i M_i \theta_i}{\sum_i M_i}. \quad (2.20)$$

Here M_i are inertia factors, θ_i are rotor angles, and θ_{COA} is the centre-of-angle reference. The key idea is to take the familiar Integral of Squared Error (ISE) structure and replace the HVDC converter variables by rotor-angle variables of multiple synchronous machines, so that the index becomes a direct measure of inter-machine resynchronization. Generators that swing furthest from the centre-of-angle (COA) are penalised most, while the inertia factors M_i prevent small machines from dominating the score.

- **Dynamic-performance metric:** Lower ISGA values unambiguously indicate better damping and faster resynchronisation after faults [71].
- **Training signal for intelligent relays:** CPI (ISGA) time-series produced by EMT simulations as the *training data* for decision-tree (DT) classifiers that issue response-based controls—e.g. out-of-step tripping or rapid HVDC power shifts—without relying on pre-defined event flags. Controls that reduce ISGA most were found to give the greatest post-fault damping, and the DT learned exactly those patterns [71].
- **Link to modal design:** By redefining the reference angle θ_{COA} as each machine's *final* rotor angle $\theta_{i,\infty}$, the same quadratic form degenerates to a standard ISE used in small-signal modal control design. [72] showed analytically (using a second-order linear model) that this ISE variant penalizes both low damping and slow time-constants, providing a seamless bridge between large-disturbance and small-signal design philosophies.

Contingency ranking and screening: [73] proved that the CPI accumulated over the first one or two seconds of a simulation is a robust predictor of eventual stability: a threshold that separate clearly stable from clearly unstable contingencies. The events whose ISGA at 1 second of post-fault time window exceeds a certain threshold almost always lose synchronism within the eight-second study window. Because the index is monotonic with respect to severity, it also provides an efficient *ranking* mechanism so that online dynamic-security-assessment (DSA) tools can rank the hundreds of contingencies based on the magnitude of CPI and track the most critical cases.

Optimising one-shot remedial actions: The same study showed how the gradient of ISGA with respect to candidate controls—load shedding and HVDC power ramp up —can drive a steepest-descent algorithm. Starting from an unstable case, the algorithm iteratively adjusted those controls until the CPI dropped below the previously established “stability” threshold, thereby *automatically* finds an effective remedial action scheme (RAS). This converts a brute-force search into a smooth quadratic optimisation problem [73].

Implications for this thesis: ISE-family CPIs deliver three benefits aligned with our objectives: (i) they condense fault-response waveforms into a scalar sensitive to both magnitude and damping; (ii) they serve as objective functions for data-driven or gradient-based emergency control; and (iii) they provide a unified metric for contingency ranking, controller tuning, and wide-area protection. Hence, the integral-square-error paradigm adopted for converter performance (HVDC controller optimisation) is equally applicable to system-level evaluation (generator-angle stability and post-fault recovery), supporting the integrated design philosophy of this thesis.

Hence, the Integral-Square-Error paradigm adopted for converter performance in pre-

vious sections (like HVDC controller optimization) is equally powerful for system-level dynamic-stability evaluation (like evaluating generator angle stability and post-fault recovery). This dual application supports the integrated design philosophy of this thesis, where both local converter stability and global network stability are evaluated using a unified performance metric.

2.3.3 Broader Applications of CPIs Beyond Power Systems

A. Non-Explicit CPI Applications

In several engineering domains a *performance index* is evaluated numerically within a detailed simulator or surrogate model—retaining the CPI philosophy (a single scalar measuring “distance from ideal behaviour”) without a closed-form expression.

Electric-vehicle autopilot design [74]. A PSCAD–EMT vehicle model is coupled to a Nelder–Mead optimiser that minimises a composite CPI comprising speed-tracking error over a standard drive cycle and state-of-charge deviation. Because each candidate gain set triggers a fresh EMT run, the CPI is *measured*, not written analytically. Reported results show a $\sim 25\%$ reduction in drive-cycle RMS error relative to manual tuning.

Piezoelectric energy-harvester optimisation [75]. A finite-element dataset feeds an ANN surrogate that maps design vectors to *average harvested power* (the CPI); a GA then searches this black-box landscape, yielding a reported $\sim 17\%$ increase over prior designs. The CPI is implicit, yet the one-scalar optimisation paradigm is preserved.

These examples indicate that CPI-style optimisation is portable whenever the metric can be *measured* at each iterate.

B. Industrial CPI Applications

Control-performance assessment (CPA), closely related to CPI-based evaluation, has become routine in industry [67]. Plants continuously log historian data; CPA/CPI modules embedded in distributed control systems (or linked optimisation engines) compute indices for large loop populations and present results via the human–machine interface (HMI). Engineers remain *in the loop*: they supply context (equipment limits, production schedules, safety constraints) and translate index trends into maintenance or retuning actions [67].

Commercial CPA/CPI software—both vendor-native and platform-agnostic—typically offers real-time index monitoring, priority ranking of underperforming loops, threshold-based alerts that generate work orders, and plant-wide oscillation detection [67]. Effectiveness hinges on clear HMI visualisation (colour-coded health summaries, drill-down trends, scheduled reports) and on empowering engineers to convert index numbers into sustained performance gains [67].

2.4 Mixed LCC–VSC HVDC Systems as a Key Modernization Alternative

High-voltage direct current (HVDC) enables long-distance bulk transfers and interconnection of asynchronous regions [76–78]. Two converter families dominate: LCC converters rely on thyristors, have proven ultra-high-voltage capabilities up to ± 1100 kV, and excel at large power ratings (above 5–10 GW), but reliant on strong AC voltage and suffer from commutation failures; and voltage-sourced converters (VSCs), use self-commutated devices like IGBTs and can offer independent reactive-power control and robust operation in weak

grids at generally higher cost for very high ratings [76, 77, 79, 80].

2.4.1 Architecture and Motivation

Definition of *Mixed* and *Hybrid* HVDC: A *Mixed LCC–VSC* link combines an LCC rectifier (sending end) with a VSC inverter (receiving end) [78, 81]. This is distinct from *hybrid terminals* that mix valve types within one station (e.g., pole-mixed or series-mixed arrangements). While many publications use the word “hybrid” to describe both arrangements, this thesis adopts the more precise distinction above [82, 83].

Motivation: In the “terminal-Mixed” architecture considered here (e.g., Bipole 1 modernization), the LCC typically regulates I_{dc} while the VSC controls V_{dc} , sharing a common DC current and voltage. This pairing leverages the LCC’s cost-efficient, high-capacity rectification with the VSC’s immunity to commutation failure, dynamic reactive support, and voltage control in weak grids [76, 78, 79].

2.4.2 Benefits for LCC–VSC Mixed Topology

Multi-Infeed Grid Benefits: Conventional LCC inverters demand strong AC voltage for commutation and risk commutation failure if the grid experiences a fault or voltage sag. A Mixed HVDC layout solves this by using the VSC as the inverter, which can:

- **Provide Dynamic Reactive Support:** VSC stations can supply or absorb reactive power as needed, stabilizing the AC voltage under normal and fault conditions [79, 81].
- **Avoid Commutation Failures:** Because the VSC does not rely on zero-crossing of the grid voltage for commutation, it is immune to classic commutation failure, thus

reducing cascading events in multi-infeed systems [79].

- **Enhance Fault Ride-Through:** During AC or DC faults, a VSC can ramp its current injection or block in a controlled manner, accelerating recovery compared to an LCC inverter [78]. In dense multi-infeed regions, a VSC inverter can bolster the local bus voltage so neighbouring LCC inverters recover more reliably [79].

2.4.2.0.1 Receiving-End Voltage and Reactive-Power Support: LCC inverters draw substantial reactive power and typically require sizable AC filters or shunt compensation [76]. In a Mixed scheme, the VSC inverter can supply or absorb Q independently, enabling direct regulation of bus voltage and often reducing—or eliminating—external compensation at the receiving end [80,81]. This capability is especially valuable in weak or urban grids: the VSC behaves STATCOM-like during disturbances by injecting reactive current to support voltage, while in normal operation it can hold a prescribed voltage set-point or operate at (near) unity power factor [78,80,81].

Economic Advantage: With respect to high ratings HVDC, a Mixed LCC–VSC layout is often more cost-effective than a full VSC–VSC scheme: an LCC at the rectifier preserves multi-GW capability (5–10 GW class, ± 800 – ± 1100 kV), while one or more lower-rated VSC inverters deliver receiving-end robustness [76,80]. The Wudongde project exemplifies this architecture—one high-rating LCC rectifier feeding two VSC inverters to transmit ~ 8 GW over ~ 1450 km—achieving improved fault tolerance at the receiving end without incurring the full cost of VSC stations at both terminals [78].

In summary, the LCC–VSC mixed scheme leverages the proven bulk-transmission capability of LCC rectifiers while incorporating VSC inverter functional advantages. This

combination simultaneously addresses distance, capacity, and cost requirements, offering a balanced pathway between established technology and modern converter innovations.

2.4.3 Mixed Topology—Design Considerations

Control Coordination Although the Mixed concept is straightforward, practical implementation demands careful coordination of controls, grounding, and protection [79]. The two terminals must share the DC variables without contention: in most designs the VSC inverter regulates the DC voltage V_{dc} , while the LCC rectifier controls the DC current I_{dc} ; alternative role assignments are possible but require explicit supervisory logic to avoid control conflicts [78, 81].

DC Fault Management At the inverter, MMCs built with full-bridge (FB) or hybrid FB/HB submodules can actively block and clear DC faults by synthesizing a counter-emf on the DC side; this enables fast fault isolation and controlled re-energization [78, 81]. On the rectifier side, the LCC can be driven into inversion or blocked by retarding the firing angle above 90° to reduce fault feed-in during clearing [78]. By contrast, half-bridge (HB) MMCs cannot sustain a blocking voltage on the DC side; fault clearance then relies on AC breaker operation and pole de-energization, and full restart can extend to the order of ~ 1 s in practical schemes [84].

Rectifier Technology and Short-Circuit Duties During the ac fault at rectifier buses, an LCC rectifier does not materially increase fault-current duties. A VSC rectifier, however, can inject controlled fault current. For the Manitoba multi-infeed grid, studies indicate that a VSC rectifier at a strong 138 kV node could raise short-circuit levels beyond typical outdoor breaker limits (e.g., 63 kA), triggering costly switchgear upgrades [84].

2.4.4 Real-World Examples and Case Studies

Several real-world examples and planned projects demonstrate the feasibility of the mixed LCC–VSC HVDC systems:

Skagerrak: Three LCC links plus a VSC link in bipolar operation between Norway and Denmark; the VSC link provides black-start and voltage-support capability [85].

Wudongde: One LCC rectifier feeding two VSC inverters to deliver ~ 8 GW over ~ 1450 km. By leveraging VSC inverters, the system avoids commutation failures at the receiving end, thereby enhancing reliability [86].

Baihetan–Jiangsu (series-hybrid, planned): A series LCC–VSC arrangement at the receiving end to offset LCC reactive demand and enhance voltage stability [85].

Luxi back-to-back: Operational example highlighting mixed or hybrid scheme’s versatility particularly in interconnecting asynchronous or weakly linked networks [87].

2.4.5 Performance and Operational Characteristics Comparison

To provide a clear understanding of the advantages offered by a Mixed LCC–VSC HVDC system, it is beneficial to compare its performance and operational characteristics with those of full LCC–HVDC and full VSC–HVDC systems. Table 2.3 summarizes key aspects of this comparison.

Table 2.3: Comparison of Full LCC-HVDC, Full VSC-HVDC, and Mixed LCC-VSC HVDC Systems

Characteristic	Full LCC-LCC	Full VSC-VSC	Mixed LCC-VSC
Power Rating	High (up to 10+ GW)	Lower (typically up to 3 GW)	Can leverage LCC for high power
Capital Cost	Lowest	Higher	Aims for balance, potentially lower than Full VSC
Power Losses	Lowest	Higher	lower than full VSC
Reactive Power	Consumes large amount	Controls independently (can supply/absorb)	VSC can compensate LCC consumption
Weak AC Grid Operation	Cannot operate effectively ($SCR < 2$)	Can operate effectively ($SCR > 1$)	VSC inverter enables operation in weak grids
Commutation Failure Risk	High risk at inverter side	No risk	Risk mitigated at inverter side
Power Flow Reversal	Requires DC voltage polarity reversal	Inherent capability (DC current reversal)	Offers flexibility depending on topology (FB-MMC)
Black Start Capability	No	Yes	VSC inverter/ Yes
Multi-Terminal DC Grids	Challenging to implement	Suitable	Can be adapted, but topology-dependent
Technology Maturity	Mature (over 70 years)	Developing	Leverages maturity of LCC
Harmonic Filtering	Requires large AC and DC filters	Requires no or smaller filters	Requirements can be reduced compared to pure LCC
Fault Current Contribution	Do not Trigger Breakers Upgrades	Fault Current Increment trigger protection re-coordination and switchgear replacement	Fault Current on low Short level side only

In summary, the mixed configuration combines LCC scale/cost advantages with VSC flexibility—supporting weak grids, reducing commutation-failure exposure, and improving receiving-end voltage control—making it a strong candidate for long-distance, high-capacity modernisation [76–78, 80, 81].

Chapter 3

Model Development

This chapter describes the models used in this research, beginning with a standalone HVDC system and later extending to a multi-infeed arrangement containing three bipoles. The main circuit design parameters are derived, and the associated control system modeling is presented (including LCC rectifier power control, Voltage Source Converter (VSC) inner/outer loops, and VSC modulation techniques).

Chapter 3 Overview

Chapter 2 reviewed the many *indices*—SCR, MIESCR, MAP/MPC, CCT, CPI, and others—that researchers use to judge multi-infeed HVDC performance. The survey highlighted a common thread: *all* of those metrics ultimately rely on credible time-domain waveforms. The purpose of the present chapter is therefore to construct the high-fidelity Electromagnetic Transient (EMT) models that will generate those waveforms for the remainder of the thesis.

Scope of Chapter 3

- **§3.1 Standalone vs. Multi-Infeed Platforms**

Explains how the individual bipole is first modelled against Thévenin sources (stand-alone case) and then embedded in a three-bipole AC/DC network so that converter–converter and converter–machine interactions are preserved.

- **§3.2 Model Setup and Study Alternatives**

Introduces the “one-bipole-under-upgrade” concept used throughout the thesis. Two technology paths—“*Mixed LCC–VSC*” and “*VSC–VSC*”—plus dual rating choices (2.8 GW and 2 GW) define the design alternatives that will be further evaluated later.

- **§3.3 Control-System Modelling**

Develops the complete hierarchy of controls implemented in PSCAD:

- Upper-level outer/inner loops for MMC-VSCs.
- Classic current and firing-angle regulation for the LCC.
- Lower-level MMC modules (CCSC, NLC, CVB).
- Hybrid coordination logic for the Mixed LCC–VSC option.

- **§3.4 Main-Circuit Parameters**

Derives, from first principles and industrial guides, the transformer voltages, MMC sub-module capacitance and arm inductance that underpin the EMT representation.

- **§3.5 Control-Mode Sensitivity Rationale**

Motivates why the inverter side of each alternative is tested in two outer-loop modes—reactive-power and AC-voltage control—and outlines the fault scenarios that will later reveal their impact on voltage- and frequency-ride-through margins.

- **§3.6 Calibrate gains with CPI-driven optimisation**

A CPI workflow (robustness-weighted system-level ISE across multiple SCRs and staged faults) uses PSCAD’s nonlinear search to yield a single consistent gain set deployed throughout the thesis.

3.1 Modeling Platforms Overview

The modeling approach in this thesis comprises two principal categories:

- **Standalone HVDC model:** A single HVDC system (the bipole slated for modernization) connected to Thevenin-equivalent voltage sources at the rectifier and inverter sides.
- **Multi-Infeed HVDC system:** Incorporating three distinct bipoles (Bipole 1, Bipole 2, Bipole 3) along with a detailed generator and transmission network.

Within the multi-infeed context, Bipole 1 is the system scheduled for future modernization, yet the final choice of topology (VSC--VSC or Mixed LCC--VSC), rating (e.g., 2800 MW vs. 2000 MW), and control model (reactive-power vs. voltage-control) is not predetermined.

3.1.1 Standalone Model: Bipole 1 Modernization Alternatives

The standalone HVDC representation for Bipole 1 considers two topologies:

- **Alternative 1 (Mixed LCC--VSC):** retain the existing LCC rectifier; upgrade the inverter to an MMC-based VSC.

- **Alternative 2 (VSC–VSC):** replace both rectifier and inverter with MMC-based VSC stations.

Each alternative is evaluated at two ratings (2800 MW and 2000 MW) and with two inverter outer-loop modes (reactive-power control vs. AC-voltage control). A summary is provided in Table 3.1. Switching from reactive-power (Q) control to **AC voltage** control at the inverter side can yield different voltage response behaviors, as studied in Chapter 6. Meanwhile, rating adjustments (2000 MW vs. 2800 MW) influence the converter’s short-term headroom for fault ride-through.

Table 3.1: Proposed Modernization Alternatives for Bipole 1

	Alternative 1	Alternative 2
Rectifier Technology	LCC	MMC (VSC)
Inverter Technology	MMC (VSC)	MMC (VSC)
Rectifier Control	P_{dc}	V_{dc} & V_{ac}
Inverter Control Mode 1	V_{dc} Droop & Q	P_{dc} Droop & Q
Inverter Control Mode 2	V_{dc} Droop & V_{ac}	P_{dc} Droop & V_{ac}
VSC Rating Option 1	2800 MW	2800 MW
VSC Rating Option 2	2000 MW	2000 MW

Figures 3.1–3.2 depict single-line diagrams of the Mixed LCC–VSC and VSC–VSC standalone configurations. Ratings and inverter control variants are indicated on the diagrams.

SCR in Thevenin-equivalent: Each standalone model uses Thevenin-equivalent AC sources at the rectifier and inverter buses. System strength is characterized by the specified SCR (short-circuit ratio), defined as the short-circuit capacity at the POC divided by the rated HVDC power [88]. To ensure consistent fault levels and impedances, the same

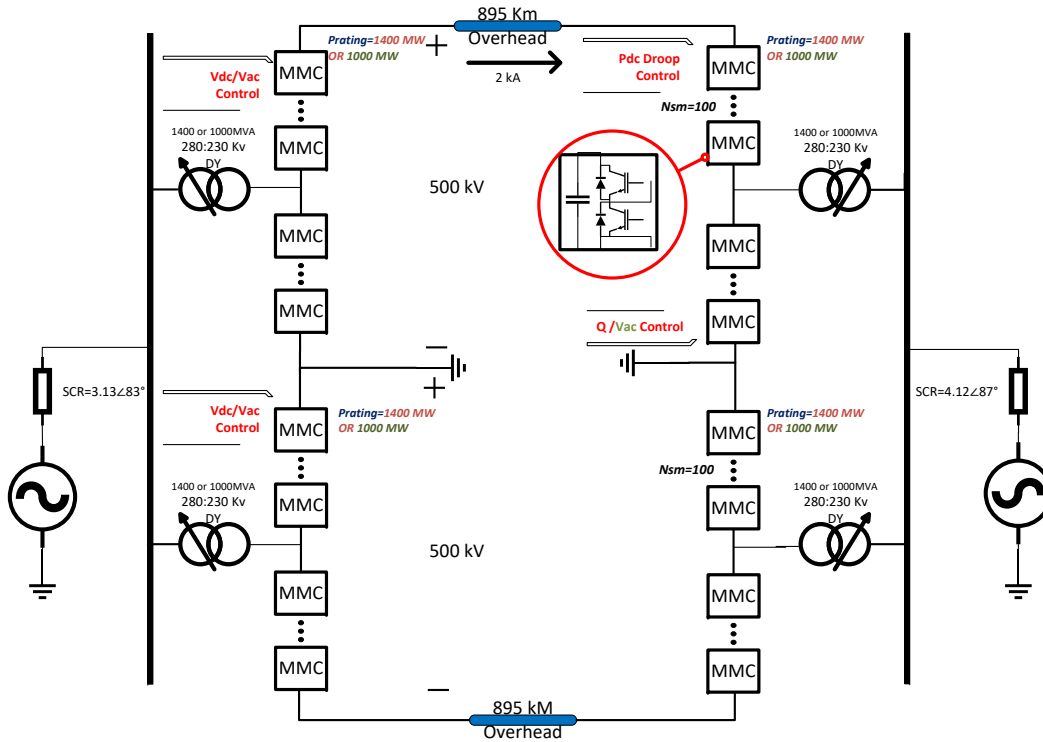
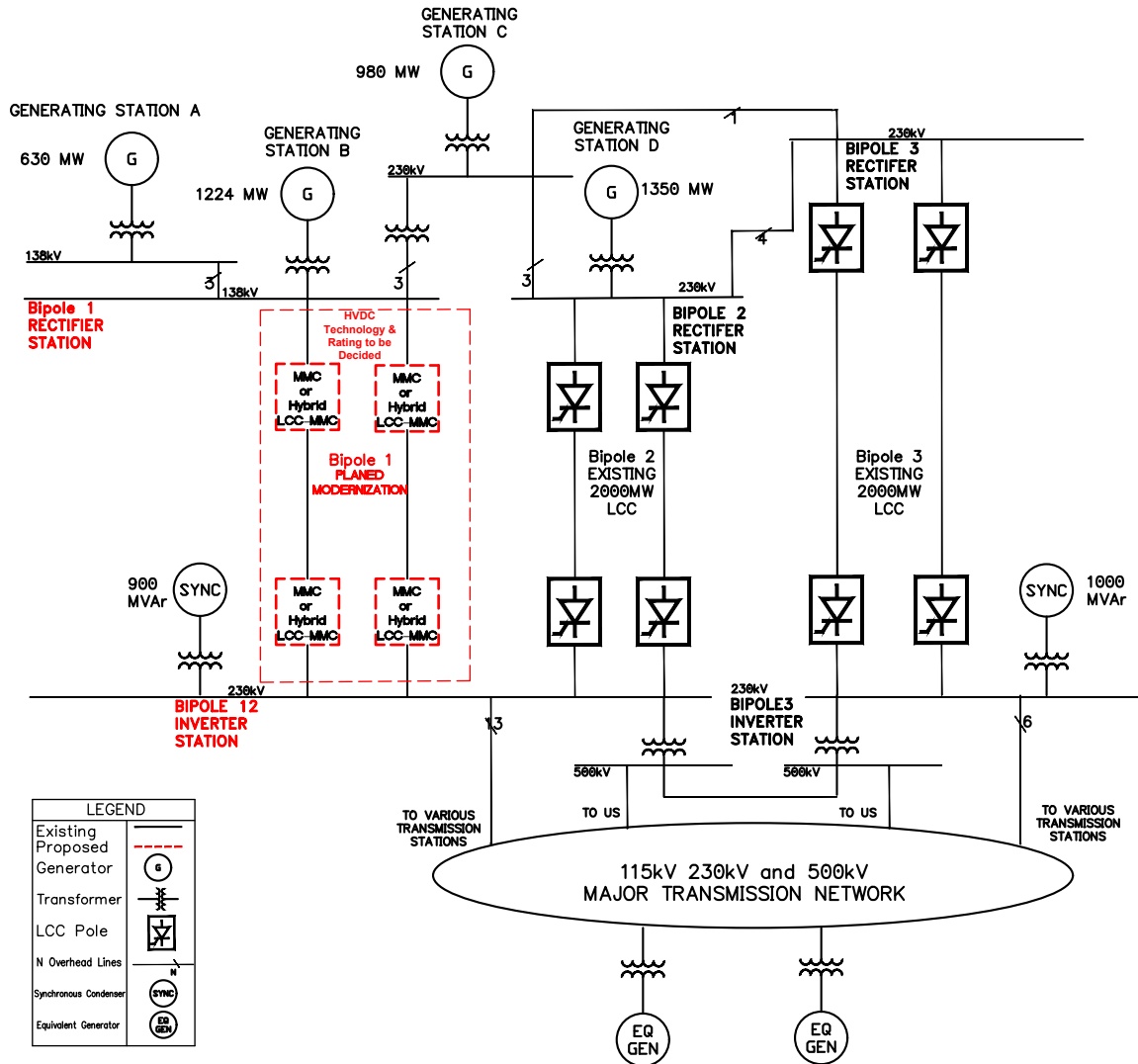


Figure 3.2: Single-line diagram of the VSC-VSC standalone HVDC system for Bipole 1.

3.1.2 Expand Standalone to Multi-Infeed Model

Having developed the standalone Bipole 1 model, the next step is to embed it into the **three-bipole multi-infeed** topology. Figure 3.3 (below) shows an overview:

- **Collector Generating System (Rectifier Side):** Four generating stations with detailed machine models (exciter, governor and Power System Stabilizer (PSS)).
- **Three DC Overhead Lines** (895 km, 937 km, 1400 km).
- **Major Transmission Network** (150 buses, 77 lines) at 115 kV, 230 kV, and 500 kV levels
- **Seven Synchronous Condensers** for additional local reactive/inertia support.
- **Equivalent Sources** at boundary buses, representing external utility or neighbor generation.
- **Three Bipole HVDC systems:**
 1. Bipole 1 (Proposed Modernization: VSC–VSC or Mixed LCC–VSC),
 2. Bipole 2 (Existing LCC, 2000 MW),
 3. Bipole 3 (Existing LCC, 2000 MW).



3.2 Model Setup and Study Alternatives

In many multi-infeed HVDC modernization programs, upgrades proceed *in stages*: one bipole is brought to the new standard while others remain unchanged. In this thesis, one bipole is assumed to be under upgrade (“modernization”) and the remaining links retain their existing technology. Consistent with this practice, the network in Fig. 3.3 highlights **Bipole 1** (proposed for upgrade) and retains **Bipoles 2** and **3** as existing LCC links. **Bipole 1** is modelled in two alternative topologies—*Mixed LCC–VSC* (LCC rectifier, MMC–VSC inverter) and *VSC–VSC* (MMC–VSC at both terminals)—with rating options (e.g., 2000 MW and 2800 MW) and inverter outer-loop modes (reactive-power vs. AC-voltage control). The comparative studies concentrate on *control performance*—specifically voltage and frequency behaviour—under standardised AC fault scenarios, quantifying how technology choice, rating, and control mode influence system-level dynamic resilience in the multi-infeed setting. Practical cost and operational complexity are important but lie outside the scope of this study.

3.3 Control System Modeling

This section concisely outlines the control architectures used in the study and how they map to converter objectives. For VSC–VSC, the *upper level* (outer+inner) sets DC/AC targets and the *lower level* (Circulating Current Suppression Control (CCSC), Nearest Level Control (NLC), Capacitor Voltage Balancing (CVB)) realizes valve switching [2]. The Mixed LCC–VSC scheme complements this: the LCC rectifier regulates DC current while the VSC inverter regulates DC voltage [1, 18].

3.3.1 VSC–VSC Control System Architecture

Upper-Level Control: The outer loop assigns DC/AC objectives by station role:

1. **Rectifier:** V_{dc} with optional Q/V_{ac} support.
2. **Inverter:** P_{dc} with selectable Q or V_{ac} regulation.

The inner loop uses standard decoupled current control in the dq frame for fast setpoint tracking.

Lower-Level Control: MMC implementations employ [2]:

- **CCSC:** suppresses second-harmonic circulating current and can be extended for over-load/frequency support [90–92].
- **NLC:** low-loss nearest-level modulation for many SMs [93–95].
- **CVB:** sorting-based capacitor-voltage balancing with low overhead [96, 97].

See Figs. 3.4–3.5 for station control blocks.

3.3.2 Outer-Loop Control in the Upper-Level Hierarchy

VSC–VSC Rectifier(Fig. 3.4): V_{dc} & V_{ac} Control. The rectifier regulates $V_{dc} = 500$ kV; enabling local V_{ac} control further stiffens the bus. Assigning the constant-voltage duty to the higher-potential rectifier end is consistent with unidirectional power transfer from generation-dominant buses to the inverter.

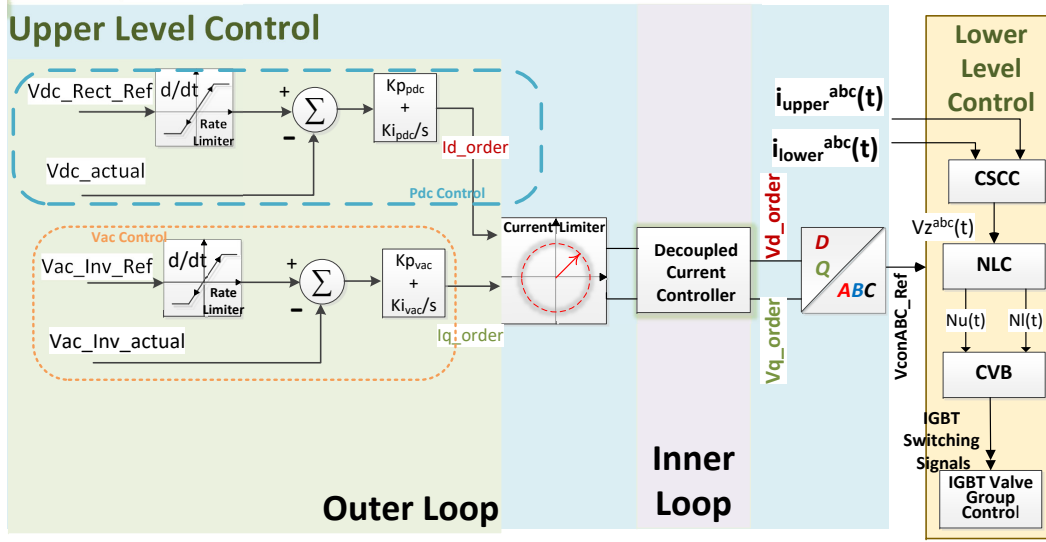


Figure 3.4: VSC–VSC Rectifier MMC V_{dc} and V_{ac} control

VSC–VSC Inverter: P_{dc} Droop & Q/V_{ac} Control. Fig. 3.5 shows the inverter regulates real power via a P_{dc} droop that accounts for $I_{dc}^2 R_{dc}$ losses and toggles between Q or V_{ac} modes for reactive support.

DC Voltage Deadband Controller: A V_{dc} deadband bias trims the power order if local DC voltage leaves a set band. If the measured inverter-side DC voltage drifts outside a specified deadband threshold, the controller biases the power setpoint, thereby counteracting large voltage swings by either increasing or decreasing the net power flow.

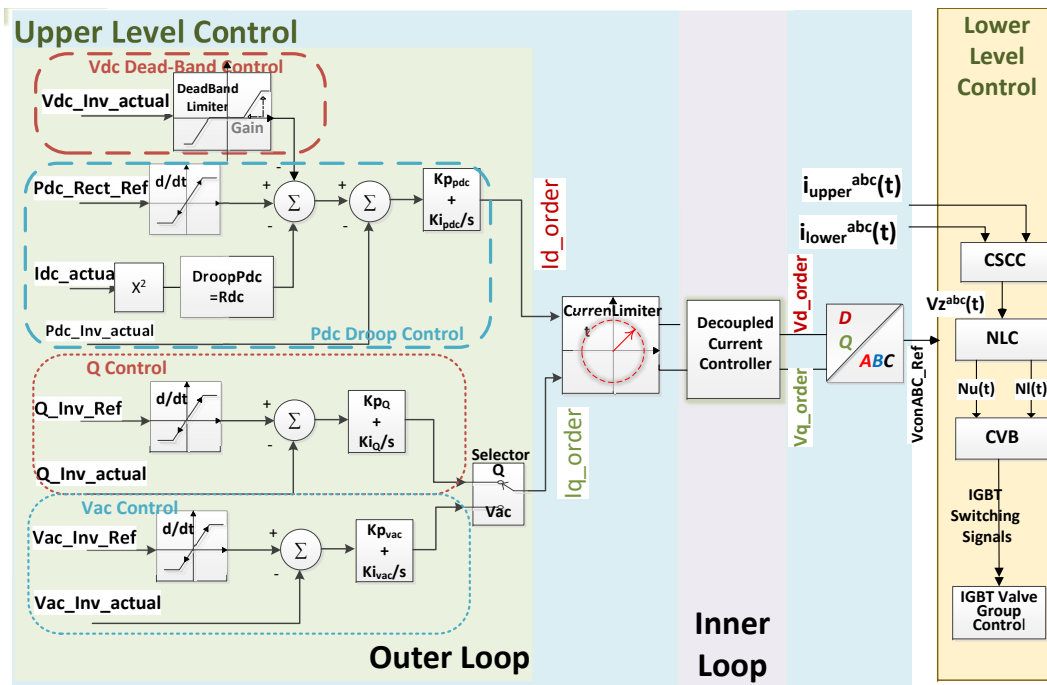


Figure 3.5: VSC-VSC Inverter MMC P_{dc} droop and Q/V_{ac} control

3.3.3 Inner-Control in the Upper-Level Hierarchy

Current Limiter Controller: The outer loop issues I_{d_order}, I_{q_order} . These orders are first passed through a current limiter that ensures the demanded dq currents do not exceed the physical current-handling capability of the IGBT valves. In practice, the current limiter incorporates a safety margin to protect the semiconductors under fault conditions or transient overloads.

Decoupled Current Controller: The decoupled current controller regulating the d -axis and q -axis currents independently, follows the Park transformation approach dq relations [98–100]. Figure 3.6 also shows the single-phase equivalent circuit of the VSC, where we define the positive flow direction from the AC grid (*system*) to the converter. In the dq reference frame, we may write the converter-side voltages as:

$$\begin{aligned} V_{d_conv} &= V_{d_sys} - L_{eq} \frac{di_d}{dt} - \omega L_{eq} i_q, \\ V_{q_conv} &= V_{q_sys} - L_{eq} \frac{di_q}{dt} + \omega L_{eq} i_d, \end{aligned} \tag{3.1}$$

where ω is the system angular frequency, i_d and i_q are the dq -axis currents, V_{d_sys} and V_{q_sys} are the system-side dq voltages at the Point of Common Coupling (PCC), and L_{eq} is the equivalent inductance (sum of the transformer leakage plus half of the arm inductor). The converter outputs V_{d_conv} and V_{q_conv} are later transformed back to three-phase AC voltages which are then inverse-Park transformed to $\mathbf{V}_{conABC_Ref}$ for the input of lower level control.

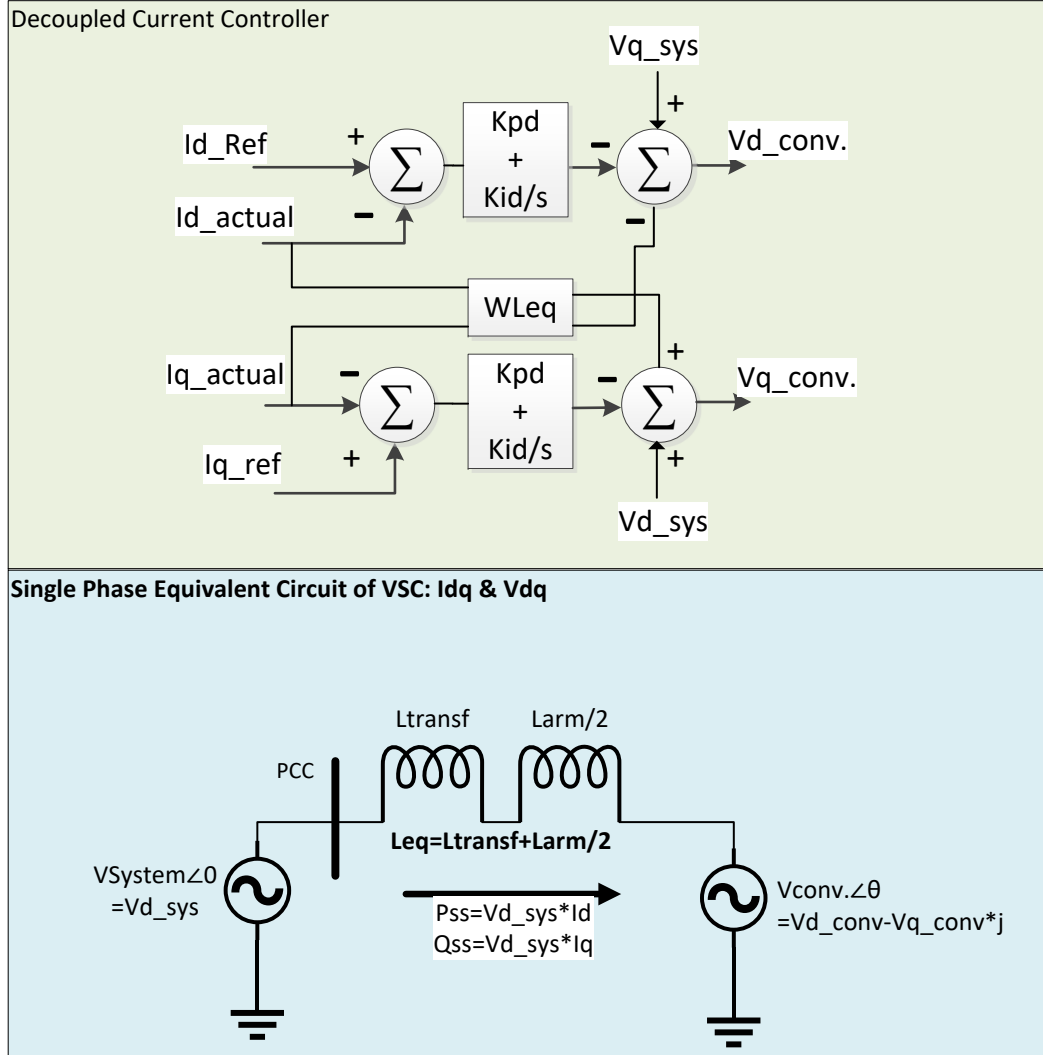


Figure 3.6: Inner-loop decoupled current controller and single-phase equivalent

3.3.4 Lower Level Control

Circulating Current Suppression Control (CCSC): CCSC was introduced to mitigate the dominant 2nd harmonic arm-current component by extracting a negative-sequence signal and synthesizing an internal leg-unbalance voltage $v_z^{abc}(t)$ that is injected at the mod-

ulator input, thereby attenuating circulating current without disturbing outer-loop AC dynamics [90]. The method was then refined to co-design CCSC with low-switching-frequency NLC and explicit capacitor-voltage balancing, achieving current suppression alongside reduced losses and preserved transient performance [91]. Building on these developments, a hybrid circulating-current controller has been proposed that deliberately shapes the 2nd harmonic component to extend the converter’s short-term power-handling capability and primary-frequency response within device limits [92]. According to Figure 3.7, the CCSC takes as inputs the upper arm current $i_{\text{upper}}^{abc}(t)$ and the lower arm current $i_{\text{lower}}^{abc}(t)$. By focusing on the second-order component within the negative-sequence (ACB) reference frame, the controller produces an output $V_z^{abc}(t)$ corresponding to the undesirable second-order harmonic component. This output is then sent to the NLC modulators.

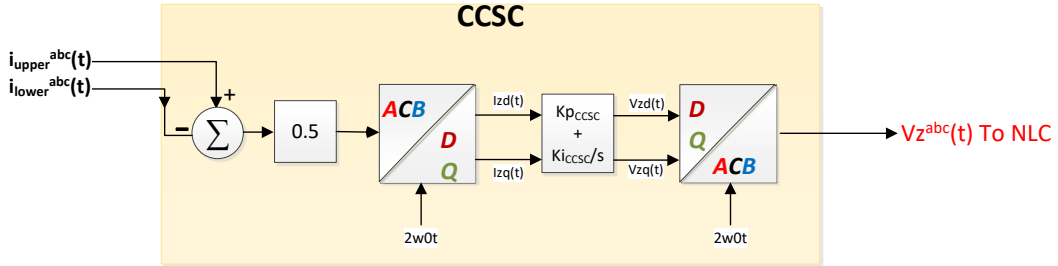


Figure 3.7: Circulating Current Suppression Control (CCSC)

Nearest-Level Control (NLC): Amplitude-based NLC maps the continuous phase converter-voltage reference directly to the nearest achievable arm level, yielding low switching loss and real-time suitability for EMT studies [94, 101, 102]. While angle- and amplitude-based variants both appear in the literature [95, 96], we adopt the amplitude-based rule recommended for EMT implementations [101, 102], which relies on a single nearest-integer operation:

$$N_u(t) = \text{Round}\left[N_{\text{sm}}\left(\frac{1}{2} - \frac{V_{\text{conv}}(t)}{V_{\text{dc}}}\right)\right], \quad N_l(t) = \text{Round}\left[N_{\text{sm}}\left(\frac{1}{2} + \frac{V_{\text{conv}}(t)}{V_{\text{dc}}}\right)\right]. \quad (3.2)$$

Here, $N_u(t)$ and $N_l(t)$ are the integers (bounded in $[0, N_{\text{sm}}]$) that specify how many submodules (SMs) are inserted in the upper and lower arms at sampling instant t ; N_{sm} is the number of SMs per arm; V_{dc} is the total dc-link voltage; $V_{\text{conv}}(t)$ is the instantaneous phase converter-voltage reference produced by the inner control; and $\text{Round}[\cdot]$ denotes the nearest-integer map. The structure of Eq. (3.2) reflects that each arm voltage consists of half the dc link plus or minus the ac converter component, so the normalized reference is converted into an arm SM count by simple integer rounding. In practice, nonuniform SM capacitor voltages are handled by sorting/error-driven balancing—selecting *which* SMs to insert without altering the counts in Eq. (3.2) [96]. Compared with high-frequency carrier PWM, NLC typically lowers switching losses and controller burden [94], with harmonic quality improving as N_{sm} increases [95]; EMT-oriented parameterization follows available guides and tutorials [101, 102].

Capacitor Voltage Balancing Algorithm: After the NLC controller determines the upper- and lower-arm counts $N_u(t)$ and $N_l(t)$, these are passed to the Capacitor Voltage Balancing (CVB) controller. The CVB objective is to keep all SM capacitor voltages approximately equal. The standard rule is: when the arm current charges the capacitors, insert the *lowest*-voltage submodules; when it discharges, insert the *highest*-voltage submodules—thereby preventing uneven energy distribution across capacitors [103].

A common implementation measures and *sorts* SM capacitor voltages in ascending/descending order, then selects either the lowest- or highest-voltage SMs based on the arm-

current sign to form the required arm voltage [97]. To avoid excessive switching, some schemes sort only when $N_u(t)$ or $N_l(t)$ changes; others apply a fixed deviation band and trigger balancing only when the spread between maximum and minimum SM voltages exceeds the threshold. A straightforward cycle-by-cycle re-sorting is performed: at each sampling instant, the highest or lowest voltages are chosen according to the arm-current direction, which is simple [93], but potentially frequent. By contrast, [96] reduces computational effort by merging sorting and gate-signal generation, pruning redundant logic, and skipping repeated sub-sort passes; it neither requires fully explicit per-pulse SM status tracking nor uses switching-state redundancies, yielding up to a 60% reduction in processor overhead relative to fully sorted approaches.

3.3.5 Mixed LCC–VSC Control System

In the mixed scheme (LCC rectifier, VSC inverter), the LCC regulates *dc current* I_{dc} while the Modular Multilevel Converter (MMC) inverter regulates *dc voltage* V_{dc} ; thus, the rectifier behaves as a current source. The rectifier-side current regulator enforcing the I_{dc} set point:

$$I_{dc} = \frac{\sqrt{2}}{X_c} V_{LL,sec,rms} \cos \alpha - \frac{\pi}{3X_c} V_{dc}. \quad (3.3)$$

where $V_{LL,sec,rms}$ is the converter-transformer secondary line-to-line rms voltage, X_c is the equivalent (commutating) reactance referred to the converter side, I_{dc} is the dc current, and α is the firing angle [18]. These standard relations motivate treating the rectifier as a current source that holds I_{dc} at its set point under normal conditions.

Figure 3.8 shows four main components in the Mixed LCC rectifier controller. This

controller is adapted and enhanced based on the benchmark model originally proposed by Szechtman et al. [1], with modifications tailored to accommodate Mixed LCC–VSC system dynamics. Main blocks:

- **Urect Calculation:** Estimates the rectifier-side DC voltage (U_{rect}), typically by measuring or inferring pole voltages at the inverter side and applying line-model or droop logic.
- **P/U Circuit:** Converts the assigned active power command (or scheduling from a higher-level runback allocator) into a per-unit reference. This circuit determines the desired P/U ratio based on the bipole's operating point.
- **Current Order Selector:** Chooses the current order from either P/U (under normal conditions) or a voltage-dependent current limiter (VDCL) when the system voltage is low. The look-up curve for $V-I_{order}$ ensures current is reduced under depressed DC voltages, preventing excessive stress on the converter.
- **Current Regulator:** The light-blue control region in Figure 3.8 enforces the final I_{dc} set point by comparing measured I_{dc} ($I_{dcBP1Actual}$) with the ordered current. This error feeds a standard *PI regulator*, which adjusts the firing angle α to achieve the required rectifier current.

VSC Inverter (Vdc Droop & Q/Vac): As illustrated in Figure 3.9, the inverter references the rectifier's 500 kV, subtracts $I_{dc}R_{dc}$ to form $V_{dc,ref}$, and adjusts I_d via PI; a mode selector enforces either Q tracking or V_{ac} regulation.

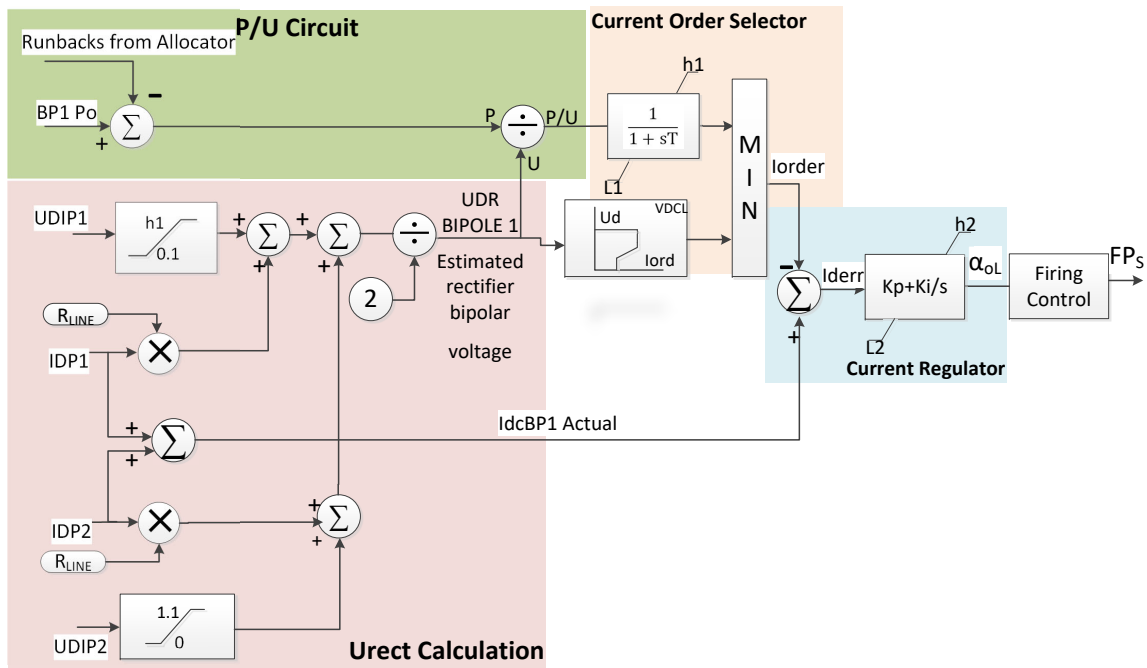


Figure 3.8: Mixed LCC rectifier: DC current regulation and order selection

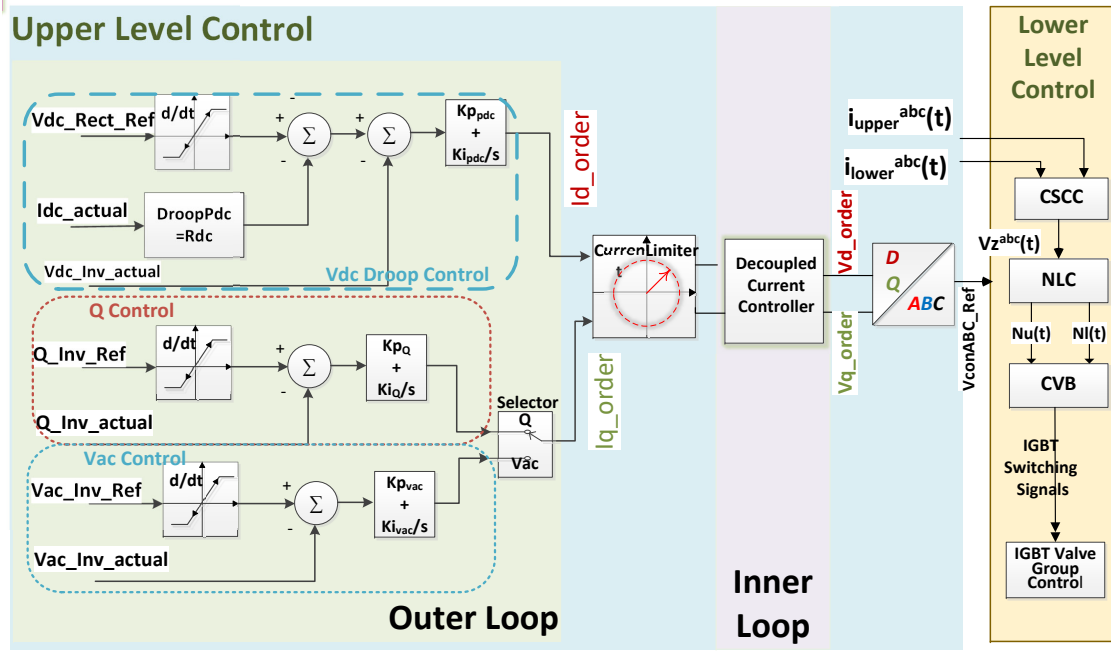


Figure 3.9: Mixed inverter MMC: V_{dc} droop and Q/V_{ac} control

3.4 Main Circuit Parameters

This section derives the principal circuit parameters used in the EMT (PSCAD) models: transformer secondary voltage, arm inductance, and submodule (SM) capacitance for the two bipole ratings (2000/2800 MW).

3.4.1 Transformer Secondary Voltage

The transformer's secondary voltage is influenced by the DC-link voltage and the modulation index during standard operational conditions. Assuming a modulation index (m) of 0.9 and a DC-link voltage (V_{dc}) of 500 kV, the peak value of the secondary phase voltage ($V_{sec.ph.peak}$) can be calculated as:

$$V_{\text{sec.ph.peak}} = \frac{m \times V_{\text{dc}}}{2} = \frac{0.9 \times 500 \text{ kV}}{2} = 225 \text{ kV} \quad (3.4)$$

Consequently, the line-to-line root mean square (RMS) voltage ($V_{\text{sec.LL,rms}}$) is:

$$V_{\text{sec.LL,rms}} = V_{\text{sec.ph.peak}} \times \sqrt{\frac{3}{2}} = 225 \text{ kV} \times \sqrt{\frac{3}{2}} \approx 280 \text{ kV} \quad (3.5)$$

3.4.2 Arm Inductor Sizing

In a modular multilevel converter (MMC), the *arm inductors* serve two primary purposes: (i) suppressing the internal double-frequency circulating currents, and (ii) limiting the $\frac{di}{dt}$ of fault currents during DC-side disturbances. Analytical and practical design insights from [104, 105] confirm that larger arm inductance reduces the amplitude of these circulating currents and offers better fault-current mitigation. However, an *excessively* high inductance can adversely affect converter dynamics and diminish the voltage modulation margin by introducing additional voltage drop across the arms.

To balance these trade-offs, an arm inductance of 0.15 p.u. is adopted, in line with guidelines from [106]. This level of inductance provides sufficient attenuation of circulating currents and moderates fault currents, while preserving acceptable control responsiveness and system efficiency for the HVDC configurations examined in this thesis.

With three-phase base S_{base} and $V_{\text{sec,LL,rms}}$ (design value), the valve-side base impedance is

$$Z_{\text{base,sec}} = \frac{V_{\text{sec,LL,rms}}^2}{S_{\text{base}}}.$$

Using $V_{\text{sec,LL,rms}} = 280$ kV:

$$Z_{\text{base,sec}}(1400 \text{ MVA}) = \frac{280^2}{1400} = 56 \, \Omega, \quad Z_{\text{base,sec}}(1000 \text{ MVA}) = \frac{280^2}{1000} = 78.4 \, \Omega.$$

Consequently, choosing 0.15 p.u. for the arm impedance at 60 Hz yields

$$L_{\text{arm,1400MW}} = 0.15 Z_{\text{base,sec}} / (2\pi f) = \frac{0.15 \times 56}{2\pi \times 60} \approx 0.023 \text{ H}. \quad (3.6)$$

With rating at 1000 MW, the arm inductance increase proportionally:

$$L_{\text{arm,1000MW}} = \frac{0.15 \times 78.4}{2\pi \times 60} \approx 0.031 \text{ H}. \quad (3.7)$$

This value ensures suitable suppression of the internal double-frequency current component and limits fault-current rise rates to manageable levels, without unduly compromising the converter's modulation capability.

3.4.3 Submodule Capacitance Sizing

Selecting submodule capacitance in MMCs presents a trade-off: excessive capacitance increases converter costs, whereas undersized values can produce large voltage ripple and exceed component ratings [106]. In this study, a target of 50 kJ/MVA is chosen for the total submodule energy storage, balancing performance and practical design constraints. According to [107], a 10% capacitor-voltage ripple requires 33–41 kJ/MVA if CCSC is applied, or 44–65 kJ/MVA without CCSC. Earlier estimates (e.g., 30–40 kJ/MVA [108]) did not fully account for converter transformers or AC system strength, which can be critical in MMC designs with enhanced fault-blocking capabilities [107]. Thus, adopting a conser-

vative 50 kJ/MVA ensures additional headroom for scenarios in which CCSC is unavailable or ineffective, promoting both operational robustness and a realistic physical footprint for high-performance MMCs.

Submodule Capacitance Computation: Let the number of submodules (SM) in each converter arm be $N_{\text{SM}} = 100$, and the DC link voltage be $V_{\text{dc}} = 500$ kV. Because there are three phases (each with an upper and lower arm), the total number of SMs per pole is

$$N_{\text{SM_Total_perPole}} = 3 \times 2 \times N_{\text{SM}} = 600. \quad (3.8)$$

The energy stored in a single SM is

$$E_{\text{SM}} = \frac{1}{2} C_{\text{SM}} (V_{\text{SM}})^2, \quad (3.9)$$

where C_{SM} is the submodule capacitance and $V_{\text{SM}} = \frac{V_{\text{dc}}}{N_{\text{SM}}} = 5$ kV. Hence, the total energy in one pole of the converter becomes

$$E = N_{\text{SM_Total_perPole}} \cdot E_{\text{SM}} = 3 C_{\text{SM}} \frac{V_{\text{dc}}^2}{N_{\text{SM}}}. \quad (3.10)$$

Energy-to-Rating Ratio: Define E_{OP} as the ratio of the converter's stored energy (in kJ) to its rated power P_{rated} (in MVA).

Assuming each pole has a rating of $P_{\text{rated}} = 1400$ MW. The relationship is

$$E_{\text{OP}} = \frac{3 C_{\text{SM}} V_{\text{dc}}^2}{N_{\text{SM}} P_{\text{rated}}}, \quad (3.11)$$

and solving for C_{SM} in millifarads yields

$$C_{\text{SM}} = \frac{E_{\text{OP}} N_{\text{SM}} P_{\text{rated}}}{3 V_{\text{dc}}^2}. \quad (3.12)$$

In this study, E_{OP} is taken as 50 kJ/MVA. Thus, for a 1400 MW rating:

$$C_{\text{SM},1400\text{MW}} \approx \frac{(50 \text{ kJ/MVA}) \times (100) \times (1400 \text{ MW})}{3 \times (500 \text{ kV})^2} \approx 9.5 \text{ mF}. \quad (3.13)$$

When the rating is reduced (e.g., 1000 MW), the required capacitance scales proportionally:

$$C_{\text{SM},1000\text{MW}} \approx \frac{(50 \text{ kJ/MVA}) \times (100) \times (1000 \text{ MW})}{3 \times (500 \text{ kV})^2} \approx 6.7 \text{ mF}. \quad (3.14)$$

Choosing a smaller converter rating reduces the necessary submodule capacitance, thus lowering hardware costs. However, it also can comprise dynamic control performance, as will be discussed in Chapter 6.

3.5 Control Modes Sensitivity Study

This section evaluates how the inverter outer-loop choice—*AC-voltage regulation* versus *reactive-power regulation*—affects dynamic performance in both modernization alternatives (Mixed LCC–VSC and VSC–VSC). The comparison is decision-relevant for weak-grid integration and multi-infeed stability, where reactive support and voltage stiffness materially influence post-fault behaviour.

Mode definitions and implementation: Consistent with industry practice, a VSC inverter may operate either in direct *reactive-power* control (Q -mode) or in *AC-voltage* control (V_{ac} -mode) [109]. In Q -mode the outer loop tracks a reactive-power setpoint and leaves bus voltage to the network; in V_{ac} -mode the outer loop regulates the point-of-connection voltage, adjusting reactive current as required. Both modes are realised over the same inner dq current controller and share the same current-limit logic (detailed see in Section 3.3).

Expected dynamic implications: In reactive power control, the converter modulates reactive power exchange with the AC grid to maintain a predefined set point. This approach is often employed when the principal objective is controlling reactive power flow, as noted in [110] for multi-terminal DC systems. In some strong AC networks, for instance, the VSC might be set to inject or absorb no net reactive power under normal operation. [109]. By contrast, V_{ac} -mode provides local voltage stiffness and typically improves transient voltage support and angle stability by delivering fast reactive current during and after faults [29, 50, 111]. These differences motivate a side-by-side sensitivity study rather than a priori selection.

Use in subsequent chapters: The mode sensitivity results are included in the Chapter 6 controller comparisons, providing evidence for selecting Q - or V_{ac} -mode at the inverter end under differing grid strengths and multi-infeed operating conditions.

3.6 PSCAD Model Optimization and PI-Tuning Process

In Section 2.2 we established a *Control-Performance-Index* (CPI) framework for HVDC-controller design, drawing on the nonlinear optimization studies of [68], [69], and [70] [68–70]. We showed that the Integral-Squared-Error (ISE) can act both as a diagnostic metric and as an objective function guiding automated gain tuning. Chapter 3 now turns from theory to practice: Section 3.6 details how the CPI concept is implemented in PSCAD to tune the proportional–integral (PI) loops of each converter and to benchmark alternative optimisation workflows.

In the previous Section 2.2 we established a *Control Performance Index* (CPI) framework for HVDC controller design, following the nonlinear, EMT-in-the-loop optimization studies in [68–70]. There, the Integral Squared Error (ISE) served both as a diagnostic metric and as an objective for automated gain tuning. This section describes the practical PSCAD workflow used to tune the proportional–integral (PI) loops of VSC and LCC controllers and to produce benchmark-ready cases for subsequent CPI ranking and evaluation of planning alternatives.

3.6.1 Optimisation Workflows for EMT-Based PI Tuning

(i) Multiple-Run Exhaustive Search

Originally described in [112], the *multiple-run* feature in PSCAD executes a grid or random sweep of user-specified parameter combinations. Each simulation returns a CPI , and the parameter set with the minimum CPI is selected.

Advantages: high probability of locating the global optimum if the search region encloses it; intuitive visualisation of parameter sensitivities. *Drawback:* computationally expensive; the number of runs grows exponentially with the dimension of the tuning vector.

(ii) Nonlinear Optimization Techniques

Here the EMT model still computes the CPI but a derivative-free optimiser (e.g. Nelder–Mead simplex, genetic algorithm) chooses new trial points automatically [68–70]. Iterations stop when the change in CPI falls below a tolerance. This strategy reduces the number of simulations compared with multiple-run sweeps, yet it requires that the CPI be explicitly returned from each PSCAD run.

(iii) Simulation-Based Surrogate Optimisation

To reduce the computational burden of exhaustive EMT simulations, *surrogate model optimisation* constructs a simplified analytical proxy for the system’s dynamic response. These models approximate the relationship between design variables and performance indices—such as harmonic distortion or over-voltage—using a limited set of simulation data.

- A quadratic Taylor-series surrogate can be built by sampling around the nominal operating point and extracting first- and second-order sensitivities of EMT outputs with respect to key parameters. This enables rapid Monte Carlo analysis and tolerance mapping with minimal simulation overhead [113].
- In [114], this approach was extended to PI and VDCOL tuning for an LCC link using space-filling design-of-experiments and surrogate-assisted solvers to minimize the ISE cost function efficiently.

As an intermediate layer, surrogate optimisation transforms a costly black-box performance index into a low-complexity analytic surface that enables faster, gradient-aware tuning.

Workflow adopted in this thesis: Unless otherwise noted, PSCAD’s built-in *derivative-free* nonlinear optimizer (workflow (ii)) was employed. The choice is pragmatic and technically well-matched to EMT studies: it is integrated into PSCAD (no external scripting or bespoke tooling), keeps the objective tied directly to simulated waveforms. With limited number of PI parameters per loop, Nelder–Mead/pattern-search-type methods converge efficiently, respect simple bound constraints, and extend cleanly to our weighted multi-scenario objective without additional coding. The approach is also widely used and validated in HVDC EMT-in-the-loop tuning [68–70], offering a good accuracy–runtime trade-off and straightforward reproducibility.

3.6.2 Robust Optimization across AC-Network Strengths

To obtain PI gains that remain effective across operating conditions, each candidate gain set is evaluated in a single $T_{\text{sim}} = 20$ s EMT run partitioned into three windows:

- a) **Initialisation** (0–10 s): system starts from cold and reaches the pre-fault operating point.
- b) **Rectifier-side fault & recovery** (10–15 s): a three-phase-to-ground fault is applied at the rectifier AC bus at $t = 10.1$ s and cleared 6 cycles later.
- c) **Inverter-side fault & recovery** (15–20 s): a second three-phase fault is applied at the inverter AC bus at $t = 15.1$ s and cleared 6 cycles later.

The time-weighting function $w_t(t)$ emphasizes disturbance and recovery intervals while de-emphasizing the initialization window:

$$w_t(t) = \begin{cases} 0.10, & 0 \leq t < 10 \text{ s}, \\ 0.45, & 10 \leq t < 15 \text{ s}, \\ 0.45, & 15 \leq t \leq 20 \text{ s}, \end{cases} \quad \text{with } 0.10 + 0.45 + 0.45 = 1.$$

Equations (3.15)–(3.16) are written for the VSC–VSC benchmark in which the rectifier enforces V_{dc} and V_{ac} and the inverter enforces P and Q . For other control-mode configurations, the set of tracked variables X is adjusted to match the active regulators. For example, in the Mixed LCC–VSC option with an LCC rectifier in I_{dc} control and a VSC inverter in P/Q control, one would use $X \in \{I_{dc,rect}, P_{inv}, Q_{inv}\}$; if the inverter instead regulates V_{ac} , then $X \in \{I_{dc,rect}, P_{inv}, V_{ac,inv}\}$. For brevity, the VSC–VSC formulation is shown explicitly below; the extensions to other control modes are analogous.

For each controller under tuning, the system-level CPI is defined as a sum of time-weighted integral-squared errors of four tracked quantities:

$$\text{ISE}_{\text{sys}} = \sum_{X \in \{V_{ac,r}, V_{dc,r}, Q_{inv}, P_{inv}\}} \int_0^T w_t(t) [X_{\text{act}}(t) - X_{\text{ref}}(t)]^2 dt, \quad T = 20 \text{ s}. \quad (3.15)$$

To ensure robustness across grid strengths, each optimization run is repeated for three short-circuit ratios, $\text{SCR} \in \{2.0, 3.0, 4.0\}$, and combined via a weighted objective:

$$\text{OF}(K_{p,x}, T_{i,x}) = \sum_{j=1}^3 w_j \text{ISE}_{\text{sys}}^{(j)}, \quad (w_1, w_2, w_3) = (0.5, 0.5, 0.25), \quad (3.16)$$

where $x \in \{V_{dc}, V_{ac}, Q, P\}$ denotes the loop being tuned and $\text{ISE}_{\text{sys}}^{(j)}$ is computed from (3.15)

at the j -th SCR case. The optimal gains $(K_{p,x}, T_{i,x})$ minimize (3.16). The weights prioritize weak and medium grids (equal emphasis) while assigning a lower weight to the strong grid, whose inherent stiffness already mitigates transients.

The CPI integral in (3.16) spans the full 0–20 s horizon, thereby penalizing (i) initial settling quality, (ii) fault-ride-through dynamics, and (iii) post-fault damping. This composite window ensures that the tuned gains remain effective not only across different AC-network strengths but also over the complete disturbance–recovery cycle used in system studies.

Chapter 3 Summary

This chapter converted the conceptual requirements that emerged from the literature review into a fully specified electromagnetic-transient platform model that is suitable to assess HVDC planning alternatives. The main achievements are recapped below.

1. **Modernisation Alternatives Defined.** Two technology pathways for Bipole 1 were formalised: a *Mixed LCC–VSC* scheme and a full *VSC–VSC* replacement, each assessed at 2.8 GW and 2.0 GW ratings and with dual inverter control modes (reactive-power versus AC-voltage).
2. **Multi–Scale Network Representation Built.** A stand-alone HVDC model was first validated against Thévenin-source terminals, then embedded in a three-bipole, 150-bus AC/DC system that preserves realistic short-circuit levels, inter-converter paths, and remote-generator dynamics.
3. **Controller Hierarchy Implemented.** All LCC and MMC control layers—outer loops, decoupled inner loops, arm-level CCSC/NLC/CVB functions, and the hybrid

VSC–LCC coordination logic—were coded in PSCAD following CIGRÉ TB 604 and benchmark guidelines.

4. **Main Parameters Derived.** Transformer secondary voltages, MMC arm inductance and sub-module capacitance were calculated from rating and performance targets and adopted consistently across cases.
5. **PI Gains Calibrated.** A derivative-free, EMT-in-the-loop optimization minimized a system-level Integral-Squared-Error objective, with robustness enforced across three grid strengths (SCR 2–4). The resulting gain sets are used in all subsequent studies.

These steps collectively deliver a high-fidelity, controller-accurate network model whose behaviour is consistent across operating points, converter technologies and grid strengths. From the next chapter onward, attention shifts from *building* the model to *using* it: Chapter 4 quantifies how each modernisation alternative shapes voltage and frequency resilience under the defined disturbance set, and establishes the CPI-based ride-through envelopes that underpin the thesis’ comparative assessment.

Chapter 4

HVDC CPI Analysis Framework

This chapter builds a normalized, system-level framework for evaluating HVDC performance using Control-Performance Indices (CPIs). The workflow proceeds in three steps: (i) per-unitization of raw ISE-based indices for power, voltage, and frequency; (ii) weighting and aggregation across fault locations and monitoring stations; and (iii) composition of voltage and frequency into a single headline metric. The methodologies developed in this chapter serve as a foundational structure for the subsequent chapters, providing a scalable and consistent approach to assessing HVDC systems under various planning alternatives.

Chapter 4 Overview

Chapter 2 established the CPI foundations and, in §2.2.2, justified the Integral-Square-Error (ISE) as the principal figure of merit. Chapter 3 then implemented those ideas in PSCAD, including the ISE-driven PI tuning workflow in §3.6. Building on that base, Chapter 4 shifts from *controller-centric* design to *system-level* appraisal: the same ISE philosophy is applied to voltage, frequency, and power waveforms at all measurement points, then nor-

malized and aggregated to produce concise, comparable indices.

Scope of Chapter 4:

- §4.1: defines the elemental CPI notation $\mathbf{X}_m\text{CPI}^n$ that tags what is measured (m) and where the contingency is applied (n).
- §4.2 lays the mathematical foundation of the *HVDC Control-Performance-Index (CPI) Analysis Framework* by converting every raw waveform into a unified per-unit space, thereby enabling fair comparison across variables, operating points, and study cases.
- §4.3 introduces a three-tier weighting scheme—*Station CPIs*, *Event CPIs*, and *System-level double aggregation*—that compresses the high-dimensional EMT responses produced for a range of contingencies into a concise set of physically interpretable scores while still flagging the most critical locations and events.
- §4.4: fuses the system-level voltage and frequency indices using two complementary composites: (i) a curve-based *UnifiedSysCPI* (geometric synthesis after scale equalization), and (ii) a score-based *SysRefScore* (normalized percentages versus a designated benchmark).

Together these sections create a self-contained *HVDC CPI Analysis Framework*: a set of data-conditioning and aggregation tools that will later be used to (i) compare single-infeed versus multi-infeed topologies (Chapter 5) and (ii) quantify the relative merits of control modes, ratings, and converter technologies in a planning context (Chapter 6).

4.1 Notation and CPI Data Element Definition

Firstly, we introduce a compact label that records *emphwhat* is measured (X), *where* it is measured (m), and *where* the fault is applied (n). The time trajectory of X measured at m under the fault condition n is written $X_m(t)|_n$ and the pre-fault steady state is X_{ss} .

Over a post-fault assessment window $T = [t_f, t_f + T_{pf}]$, the elemental CPI adopts the integral-of-squared-error (ISE) form (see the ISE rationale in Section 2.2.2):

$$\boxed{\mathbf{X}_m \text{CPI}^n} = ISE(X_m, t)|_n = \left(\int_T (X_m(t) - X_{ss})^2 dt \right)|_n \quad (4.1)$$

where:

- $X \in \{P, f, V\}$ denotes the measured quantity: active power, frequency, or voltage.
- The subscript m identifies the *measurement location* (e.g., BP1-Rectifier, BP1-Inverter, or a system bus).
- The superscript n identifies the *fault location* chosen from the same station set.
- t_f is the fault inception time; T_{pf} is the post-fault window length used for assessment.
- X_{ss} is the pre-fault steady-state value (e.g., $V_{ss} \approx 1$ pu, $f_{ss} \approx 60$ Hz, and P_{ss} equal to the scheduled transfer).

4.2 Per-Unitization

In all subsequent chapters the raw, dimensioned control–performance indices are converted to a *per-unit* (pu) scale so that power, frequency, and voltage excursions can be compared directly. The *per-unit* (p.u.) system rescales every quantity to its own rated value, so that power, voltage and frequency indices share a common [p.u.] axis. By scaling raw data, the per-unit approach eliminates the need to manage large or small numerical ranges during analysis, improving clarity and reducing the likelihood of computational errors.

The per-unitization process is based on a formula that applies a consistent principle across all assessed parameter X , where X represents power, voltage, or frequency, the per-unit CPI can be expressed in Equation 4.2:

$$\mathbf{X}_m \text{CPI}^n = \frac{\sqrt{X_m \text{CPI}_{\text{raw}}^n} \times 100\%}{T_{pf} \times X_{\text{Rated}}} \text{ [pu/s]} \quad (4.2)$$

- $X_m \text{CPI}_{\text{raw}}^n$ is the un-normalised ISE captured from the EMT waveform of X at station m when the fault is applied at n ;
- X_{Rated} denotes the system’s rated value for the parameter.
- T_{pf} is the total duration over which the CPI is assessed, measured in seconds.

Table 4.1 presents the per-unitized CPI of power, voltage and frequency under rectifier- and inverter-side three-phase six-cycle AC faults, and the indices evaluated over a $T_{\text{pf}} = 5$ s post-fault window. These per-unit values scale large and small numerical data into manageable ranges, ensuring consistency across parameters while retaining physical meaning. For example, the power deviation index at Bipole rectifier ($\mathbf{P}_{\text{BP}} \text{CPI}^{\text{Rect}}$) is normalized to 1.527 pu/sec. By scaling values to consistent per-unit terms, the results become easier to

interpret, particularly when comparing different parameters such as power, frequency, and voltage.

Table 4.1: Bipole 1 VSC Standalone Case CPI Per-Unit Data Results— $\mathbf{X}_m\text{CPI}^n$

n=Fault Location	m= Monitored stations; $m \in \{\text{Rect, Inv, BP}\}$				
	$\mathbf{P}_{\text{BP}}\text{CPI}^n$ [pu/s]	$\mathbf{f}_{\text{Rect}}\text{CPI}^n$ [pu/s]	$\mathbf{f}_{\text{Inv}}\text{CPI}^n$ [pu/s]	$\mathbf{V}_{\text{Rect}}\text{CPI}^n$ [pu/s]	$\mathbf{V}_{\text{Inv}}\text{CPI}^n$ [pu/s]
Rectifier (Rect.)	1.527	0.166	0.029	6.151	0.182
Inverter (Inv.)	1.854	0.040	0.208	0.173	5.980

Each entry— $\mathbf{X}_m\text{CPI}^n$ with $m, n \in \{\text{Rect, Inv}\}$ —represents the per unit data CPI of variable $X \in \{P, V, f\}$ monitored at station m when a three-phase fault is applied at station n .

4.3 Parameter Weighting and Aggregation

After per-unitization, the Control Performance Indices (CPI) are further processed to capture the aggregate performance of the entire HVDC link, accounting for contributions from both the rectifier and inverter converter stations.

4.3.1 Weighting Factors for Stations and Fault Events

Each element in the per-unit CPI matrix, denoted as $\mathbf{X}_m\text{CPI}^n$ with $X \in \{f, V, P\}$, quantifies the deviation in a physical performance variable X (frequency, voltage, or power) *measured at* converter station m in response to a fault *applied at* location n . This 2×2 structure captures the pairwise impact of specific faults on each terminal's dynamic behavior.

To transform this matrix into interpretable system-level indices, a two-stage aggregation is performed: (1) across fault scenarios and (2) across monitoring stations. Importantly, the

weighting factors used in this process depend on the physical quantity X under analysis, and thus carry a superscript for clarity.

These parameter-specific weights are defined as:

- W_{X_m} : Station weighting factor for variable X , reflecting the rating weighted of converter m in assessing system performance for X .
- W_{X_n} : Fault weighting factor for variable X , indicating the statistical likelihood, operational risk, or planning priority of specific contingencies n .

Unless otherwise specified, all CPI aggregation procedures in Chapter 4 adopt uniform weighting for both fault locations and monitoring stations, i.e., W_{X_m} and W_{X_n} are set equally for all $X \in \{\text{frequency, voltage}\}$. In subsequent chapters, however, these weighting factors are selectively adjusted to reflect system-specific dynamics and measurement priorities.

The next subsections (4.3.2& 4.3.3) formalize these aggregation operations mathematically and demonstrate the process of the CPI matrix and its successive reductions to terminal-level and system-level indices.

4.3.2 Aggregation of Station and Event Indices

To obtain interpretable system-level performance scores, the CPI matrix elemental data- $\mathbf{X}_m \text{CPI}^n$ is aggregated across fault locations n and monitoring stations m . Let $\mathcal{M}$ denote the set of converter stations (e.g., $\{\text{Rect}, \text{Inv}\}$) and $\mathcal{N}$ the set of fault locations considered. Unless otherwise stated, the weighting vectors $\{W_{X_m}\}_{m \in \mathcal{M}}$ and $\{W_{X_n}\}_{n \in \mathcal{N}}$ are taken uniform for each physical quantity $X \in \{f, V, P\}$; when non-uniform weights are used, they are

chosen such that $\sum_{m \in \mathcal{M}} W_{X_m} = 1$ and $\sum_{n \in \mathcal{N}} W_{X_n} = 1$. Eqs. (4.3)–(4.5) below formalize the aggregation steps when evaluating converter station robustness or fault severity.

Station-CPI (StnCPI): converter–station robustness The *Station-CPI*, denoted $\mathbf{X}_m \text{StnCPI}$, aggregates the impact of all studied faults n on a specific monitoring station m . This metric reflects the resilience of that station to a range of faults and is defined as:

$$\mathbf{X}_m \text{StnCPI} = \sum_n W_{X_n} \cdot \mathbf{X}_m \text{CPI}^n. \quad (4.3)$$

This aggregation metric answers the question: *How robust is station m under the studied fault scenarios?* It is particularly useful when identifying the weakest element in a multi-terminal HVDC system.

Event-CPI (EvtCPI): contingency severity The *Event-CPI*, denoted $\mathbf{X} \text{EvtCPI}^n$, compresses the impact of a specific fault location n across all monitoring stations. This row-wise aggregation is expressed as:

$$\mathbf{X} \text{EvtCPI}^n = \sum_m W_{X_m} \cdot \mathbf{X}_m \text{CPI}^n. \quad (4.4)$$

This metric reflects how severe fault n is from a system-wide perspective, answering the question: *How damaging is this fault scenario?* Such insight is crucial when prioritizing faults for protection coordination or resilience design.

System-CPI (SysCPI): Double Aggregation of Fault and Station Impacts The *System-CPI*, denoted $\mathbf{X}_{\text{SysCPI}}$, provides a single headline score for the entire HVDC config-

uration by combining all station and fault contributions into a single weighted sum:

$$\mathbf{X}_{\text{SysCPI}} = \sum_{m \in \mathcal{M}} W_{X_m} \left(\sum_{n \in \mathcal{N}} W_{X_n} \mathbf{X}_m \text{CPI}^n \right) = \sum_{n \in \mathcal{N}} W_{X_n} \mathbf{X}_{\text{EvtCPI}}^n = \sum_{m \in \mathcal{M}} W_{X_m} \mathbf{X}_m \text{StnCPI}. \quad (4.5)$$

Either form is equivalent and may be convenient depending on whether station or event summaries are already available.

Station Performance Reference Score (StnRefScore): Converter Station Comparison Metric : With the *Station-CPI* already defined in Eq. (4.3), planners still need a *single, dimensionless indicator* that ranks each converter terminal against the *best* performer in the candidates. We therefore introduce the **Station Performance Reference Score**:

$$k = \arg \min_{m \in \mathcal{M}} \mathbf{X}_m \text{StnCPI} \\ \mathbf{X}_m \text{StnRefScore} = \frac{\mathbf{X}_k \text{StnCPI}}{\mathbf{X}_m \text{StnCPI}} \times 100\% \quad (4.6)$$

where the denominator is the Station-CPI of converter m for the physical quantity $X \in \{\text{frequency, voltage, power}\}$, and the numerator is the *smallest* Station-CPI observed across all converters at the converter station k . Because a lower CPI signifies smaller post-fault fluctuation in a specified physical quantity, the station exhibiting the *minimum* StnCPI is deemed the most robust and is normalized to a score of 100%.

This aggregation framework supports multi-dimensional screening: contingency severity ranking via Event-CPI, site vulnerability analysis via Station-CPI, location-based performance comparison via normalized Station-Reference-Score, and system-wide resilience benchmarking through System-CPI. The following subsection illustrates these formulas numerically, showing how per-unit CPI values from a fault-station matrix are aggregated into

system-level screening metrics using a representative table.

4.3.3 From Matrix to Metric: Event, Station, and System-Level Aggregation

Table 4.2 illustrates the weighted aggregation procedure for both the frequency ($X = f$) and voltage ($X = V$) Control Performance Indices. The inner 2×2 matrix contains the per-unit CPI values $\mathbf{X}_m \text{CPI}^n$, each quantifying the post-fault deviation at monitoring station m due to a fault applied at location n .

Table 4.2: System-, Station-, and Event-Level CPI Results in Frequency and Voltage Domains

(a) Frequency domain: $\mathbf{f}_m \text{CPI}^n$

Fault	$m = \text{Rect}$	$m = \text{Inv}$	$\mathbf{fEvtCPI}^n$
Rect	0.166	0.029	0.079
Inv	0.040	0.208	0.187
$\mathbf{f}_m \text{StnCPI}$	0.103	0.118	$\mathbf{f}_{\text{SysCPI}} = 0.133$
$f_m \text{StnRefScore}$	100%	87.3%	—

(b) Voltage domain: $\mathbf{V}_m \text{CPI}^n$

Fault	$m = \text{Rect}$	$m = \text{Inv}$	$\mathbf{VEvtCPI}^n$
Rect	6.151	0.182	4.351
Inv	0.173	5.980	4.230
$\mathbf{V}_m \text{StnCPI}$	3.162	3.081	$\mathbf{V}_{\text{SysCPI}} = 4.291$
$V_m \text{StnRefScore}$	97.5%	100%	—

Grey = Event-CPI; Green = Station-CPI / Station Reference Score; Yellow = System-CPI.

To extract actionable information, these raw entries are aggregated along two directions:

- *Row-wise (Event-CPI)*: Each row collapses the impact of a single fault scenario across

all stations into a contingency-specific score, $\mathbf{XEvtCPI}^n$, using Eq. (4.4). These values appear in the grey margins and help rank the severity of fault locations. For example, the frequency Event-CPI for an inverter fault is $\mathbf{fEvtCPI}^{\text{Inv}} = 0.187$, which is notably larger than that for a rectifier fault (0.079), indicating higher system-wide frequency deviation severity under inverter disturbances.

- *Column-wise (Station-CPI)*: Each column aggregates the effect of all fault cases on a given monitoring station into a location-based score, $\mathbf{X}_m\text{StnCPI}$, using Eq. (4.3). These appear in the green margin and indicate the relative vulnerability of each station. In this case, the inverter station shows slightly lower voltage disturbance ($3.081 < 3.162$), implying that the rectifier bus demands stronger voltage control support.
- *Double Aggregation (System-CPI)*: At the intersection of the row and column summaries lies the fully condensed scalar $\mathbf{X}_{\text{SysCPI}}$, shown in yellow. This single value aggregates all fault events and all monitoring stations into one global score per type. For frequency, $\mathbf{f}_{\text{SysCPI}} = 0.133$ pu; for voltage, $\mathbf{V}_{\text{SysCPI}} = 4.291$ pu. These represent the system-wide average response and serve as core inputs for later composite indices.
- *Station-Performance Reference Score (StnRefScore)*: The bottom green row converts each $\mathbf{X}_m\text{StnCPI}$ into a *dimensionless ranking* by normalising with the best performer, following Eq. (4.6). A value of 100 marks the most resilient terminal for the quantity X ; smaller values quantify how far the remaining sites lag behind. In the present example the rectifier attains 100 % for frequency (out-performing the inverter by 12.7 %), whereas its voltage score drops to 97.5 % (under-performing the inverter by 2.5 %). StnRefScore , therefore, provides an immediate, cross-station quantified comparison that is independent of the physical units of the original CPI.

This table above demonstrates the stepwise reduction from a fault–station CPI matrix to scalar system-level scores for each physical quantity; in the next section (Section 4.4), these voltage and frequency System-CPI values are further integrated to construct a unified composite metric for overall HVDC resilience.

4.4 Composition of Voltage and Frequency Indices

High-voltage direct-current (HVDC) systems subjected to AC faults experience complex excursions in both *voltage* and *frequency*. Because these quantities operate on vastly different physical scales—voltage deviations reaching tens of percent and frequency shifts often within a few tenths of one or two hertz—directly aggregating their corresponding Control-Performance Indices (CPIs) into a single metric requires thoughtful treatment. Without appropriate scaling, voltage would numerically dominate any composite index, obscuring the frequency response’s contribution to system resilience.

To condense the frequency and voltage CPIs into a unified, system-level indicator while preserving interpretability and analytical rigor, this section presents two complementary fusion methodologies:

- i) **Curve-Based Method (UnifiedSysCPI)** (§4.4.1) - rescales the frequency system CPI to match the voltage scale and computes the geometric distance from the origin to the aggregate $(f_{\text{SysCPI}}, V_{\text{SysCPI}})$ point. It retains visual and numerical traceability to individual fault events, making it well-suited for methodological transparency and for explaining how multi-contingency effects are synthesized into a single representative value.
- ii) **Score-Based Method (SysRefScore)** (§4.4.2) – converts each system CPI

($f_{\text{SysCPI}} \& V_{\text{SysCPI}}$) as a percentage relative to a reference scenario. Voltage and frequency scores are combined with equal weight, resulting in an intuitive, normalized metric suitable for system-level ranking and quantifying relative performance gaps across planning alternatives.

These two methods address different planning and analysis needs. The *curve-based* UnifiedSysCPI is especially effective in visualizing fault-specific contributions and observing how fault diversity evolves across increasing system complexity (e.g., from two-terminal to multi-infeed layouts). In contrast, the *score-based* SysRefScore enables easy comparison between multiple planning alternatives by quantifying performance degradation relative to a known ideal.

Together, these techniques provide a dual lens for interpreting HVDC fault response—one rooted in geometric synthesis, the other in comparative benchmarking. Both will be applied in subsequent chapters to evaluate the frequency–voltage dynamics of alternative HVDC configurations under various converter fault scenarios.

Before diving into the two fusion methods, Table 4.3 maps the three-layer workflow and points to where each construct is defined. We then detail the two Layer-3 fusion methods in §4.4.1 and §4.4.2.

Table 4.3: Triple Aggregation Layers in the CPI Framework

Aggregation Layer	Operation	Purpose / Interpretation
Layer1: Event-CPI & Station-CPI	<i>Row-wise (EvtCPI):</i> Summarize each row of the fault-station matrix into a contingency-specific index. <i>Column-wise (StnCPI):</i> Summarize each column into a station-specific index.	<i>EvtCPI:</i> Ranks the severity of each fault scenario across the HVDC system. <i>StnCPI:</i> Ranks the vulnerability of each station across multiple fault events.
Layer2: System-CPI (SysCPI)	Double aggregation: Combine all Event- and Station-CPI contributions into one scalar for each physical variable ($X \in \{f, V\}$).	Provides a single headline index per physical quantity (e.g., $\mathbf{f}_{\text{SysCPI}}$ and $\mathbf{V}_{\text{SysCPI}}$), reflecting overall system resilience to all contingencies.
Layer3: Composite Indices (UnifiedSysCPI / SysRefScore)	Fuse $\mathbf{f}_{\text{SysCPI}}$ and $\mathbf{V}_{\text{SysCPI}}$ into one value using: • <i>UnifSysCPI (curve-based):</i> absolute geometric distance from the origin. • <i>SysRefScore (score-based):</i> normalized relative performance against a benchmark.	<i>UnifiedSysCPI:</i> Captures absolute deviation severity while preserving physical interpretation. <i>SysRefScore:</i> Enables relative, unit-less comparisons across technologies or configurations.

4.4.1 Unified System CPI (UnifiedSysCPI)

To combine voltage and frequency SysCPIs without bias from differing magnitudes, we introduce a *scaling factor* that equalises typical frequency and voltage levels prior to geometric aggregation. Let $\mathbf{VEvtCPI}^n$ and $\mathbf{fEvtCPI}^n$ denote the event-level CPIs for voltage and frequency for fault event n . Define robust *typical* values (e.g., medians across events)

$$\hat{V} = \text{median}_n\{\mathbf{VEvtCPI}^n\}, \quad \hat{f} = \text{median}_n\{\mathbf{fEvtCPI}^n\},$$

and the voltage-to-frequency scaling factor

$$R_{V/f} = \frac{\hat{V}}{\hat{f}}. \quad (4.7)$$

which directly compares the *final aggregated* voltage and frequency indices. Multiplying the frequency index by $R_{V/f}$ yields a scaled frequency term:

$$f'_{\text{SysCPI}} = f_{\text{SysCPI}} \times R_{V/f}. \quad (4.8)$$

In this way, the frequency and voltage measures become numerically comparable.

Once the scaling is applied, a Unified System CPI (UnifiedSysCPI) index can be formed via a geometric summation:

$$\text{UnifiedSysCPI} = \sqrt{(V_{\text{SysCPI}})^2 + (f'_{\text{SysCPI}})^2} \quad (4.9)$$

Figure 4.1 illustrates the construction by plotting the event-level points ($\mathbf{fEvtCPI}^n$, $\mathbf{VEvtCPI}^n$) (orange markers) and the double-aggregated system point ($\mathbf{f}_{\text{SysCPI}}$, $\mathbf{V}_{\text{SysCPI}}$) (red marker) in

the frequency–voltage plane; the yellow vector shows the magnitude of UnifiedSysCPI after rescaling via (4.7)–(4.8).

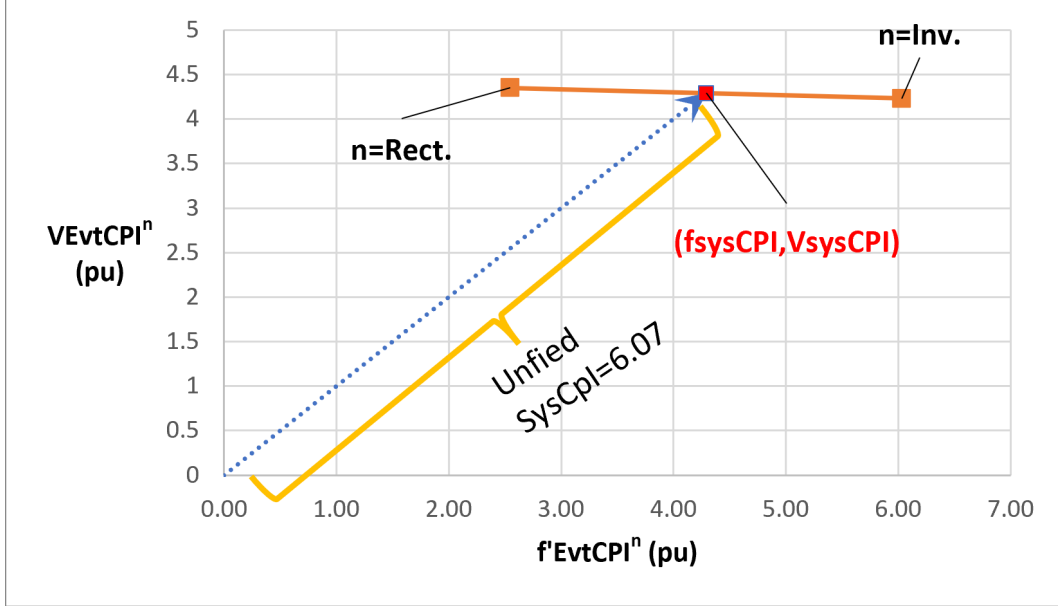


Figure 4.1: Standalone HVDC: Aggregated System CPI and Fault-Specific Event CPIs

This visualization not only clarifies how individual contingency impacts (rectifier-side vs. inverter-side faults) contribute to the overall system stress, but also highlights the utility of the UnifiedSysCPI as a concise scalar measure. It retains event-level transparency while delivering a condensed metric for comparing system robustness. This unified scaling approach is also applied in later chapters to analyze multi-infeed configurations and compare HVDC planning alternatives under various system designs.

4.4.2 System Reference Score (SysRefScore)

An effective strategy for evaluating voltage and frequency CPIs is to employ a *Reference Score* methodology. In this approach, individual voltage and frequency SysCPIs are first

computed for each scenario or system configuration; subsequently, each SysCPI is expressed as a percentage relative to a chosen reference scenario. In this chapter, the reference is the *minimum* system CPI observed in the standalone HVDC model. Because the standalone model has an infinite voltage source and minimal coupling with adjacent systems, it generally produces the smallest CPI deviations. In later chapters, the best-performing system (with the lowest system-level CPI) is chosen as the benchmark for comparing different control modes, ratings, or HVDC topologies.

To merge voltage and frequency reference scores into a single metric, define the SysRefScore

$$\begin{aligned}
 k_V &= \arg \min_{p \in \mathcal{P}} V_{\text{SysCPI}}(p) \\
 k_f &= \arg \min_{p \in \mathcal{P}} f_{\text{SysCPI}}(p) \\
 \text{SysRefScore}(j) &= W_v \frac{V_{\text{SysCPI}}(k_V)}{V_{\text{SysCPI}}(j)} + W_f \frac{f_{\text{SysCPI}}(k_f)}{f_{\text{SysCPI}}(j)} \quad (4.10)
 \end{aligned}$$

where $\mathcal{P}$ denotes the set of candidate HVDC plans and $j \in \mathcal{P}$ is the plan under evaluation. The indices k_V and k_f identify the plans attaining the minimum voltage and frequency System-CPIs, respectively. Thus SysRefScore(j) compares system j to the best performer k_v or k_f along each axis, with W_v and W_f setting the relative emphasis. A larger score indicates that j is closer to the componentwise best; for $X \in \{V, f\}$, each ratio $X_{\text{SysCPI}}(k_X)/X_{\text{SysCPI}}(j)$ equals 100% when j itself attains that domain's minimum. In Chapter 4 we take $\mathcal{P} = \{\text{standalone, multi-infeed}\}$ to quantify the performance gap between those two cases; in Chapters 5–6 the same formula is applied with $\mathcal{P}$ equal to the set of all planning alternatives.

Equal weighting on Voltage and Frequency. Throughout this thesis we assign equal importance to voltage and frequency deviations ($W_v = W_f = 0.5$). With this choice the SysRefScore becomes the simple average of the two parameter-level scores, providing an intuitive preliminary screening tool for assessing overall system performance across multiple scenarios.

Table 4.4 provides an illustrative example. The standalone HVDC model is normalized to 100% for both voltage and frequency, being the “ideal” reference. The multi-infeed model exhibits a 95% score for voltage and 44% for frequency, culminating in an overall score of 70%. Hence, the multi-infeed system retains 70% of the standalone’s benchmark performance, indicating a 30% performance gap attributable to inter-bipole coupling and shared-grid interactions. Such reference-based scoring offers an intuitive interpretation: a higher SystemRefScore implies a closer match to the ideal reference, whereas a lower SystemRefScore denotes larger voltage and frequency fluctuations during the fault recovery.

Table 4.4: Example Reference-Score Comparison: Standalone vs. Multi-Infeed HVDC

System	$V_{\text{SysCPI}_{\text{RefScore}}}$ (V_{SysCPI})	$f_{\text{SysCPI}_{\text{RefScore}}}$ (f_{SysCPI})	SysRefScore
Standalone HVDC (Ref.)	100% (4.291)	100% (0.133)	100%
Multi-Infeed HVDC	95% (4.5038)	44% (0.3031)	70%

4.4.3 Comparison Between UnifiedSysCPI and SysRefScore

To further highlight the complementary nature of the two composite index methods, Table 4.5 summarizes their key characteristics side-by-side. The curve-based *UnifiedSysCPI* approach retains physical intuition through geometric interpretation and preserves visi-

bility into individual fault event contributions. In contrast, the score-based *SysRefScore* method prioritizes normalized comparisons, making it easier to benchmark system performance across alternative technologies. Each method offers distinct advantages depending on whether the analysis emphasizes technical traceability or comparative clarity.

Table 4.5: Comparison of UnifiedSysCPI and SysRefScore Approaches

Method	UnifiedSysCPI (Curve Based)	SysRefScore (Score-Based)
Definition	Geometric norm after CPI scaling	Reference-based ratio (benchmarking)
Topology Use	Visualizes individual events and integration of multiple events	Benchmarks system vs another system (e.g., cross-technology)
Traceability	Shows contribution from individual events	Hides individual contingency impact
Cognitive Style	Engineering/analytical insight	Managerial/decision-making clarity
Output Type	Absolute scalar value (e.g., 6.07)	Normalized percentage (e.g., 70%)
Reference Required?	No (uses internal scale via R_v/f)	Yes (requires external baseline for comparison)
Comparative Interpretation	“How far from origin” (absolute deviation)	“How close to reference” (relative performance)
Applications	Methodological Transparency (UnifiedSysCPI): - Enables engineers and researchers to trace how the system-level CPI is derived. - Maintains a <i>visual connection to individual event contributions</i>, aiding interpretability. - Facilitates comparison of planning options based on their response to diverse fault conditions.	Comparative Decision-Making (SysRefScore): - Delivers a <i>normalized, bounded score</i> that simplifies system ranking and selection. - Enhances clarity when evaluating different HVDC technologies, ratings, or control strategies. - Improves accessibility for non-technical stakeholders unfamiliar with the CPI concepts.

Chapter 4 Summary

Chapter 4 consolidates an ISE-based, per-unit CPI framework and a three-layer aggregation that maps the event–station matrix $\mathbf{X}_m\text{CPI}^n$ to $\mathbf{X}\text{EvtCPI}^n$, $\mathbf{X}_m\text{StnCPI}$, and a scalar $\mathbf{X}_{\text{SysCPI}}$, then composes system-level voltage and frequency via a curve-based *UnifiedSysCPI* or a score-based *SysRefScore*. Figure 4.2 visualises this hierarchy, which Chapters 5–6 reuse for multi-infeed analysis and alternative ranking.

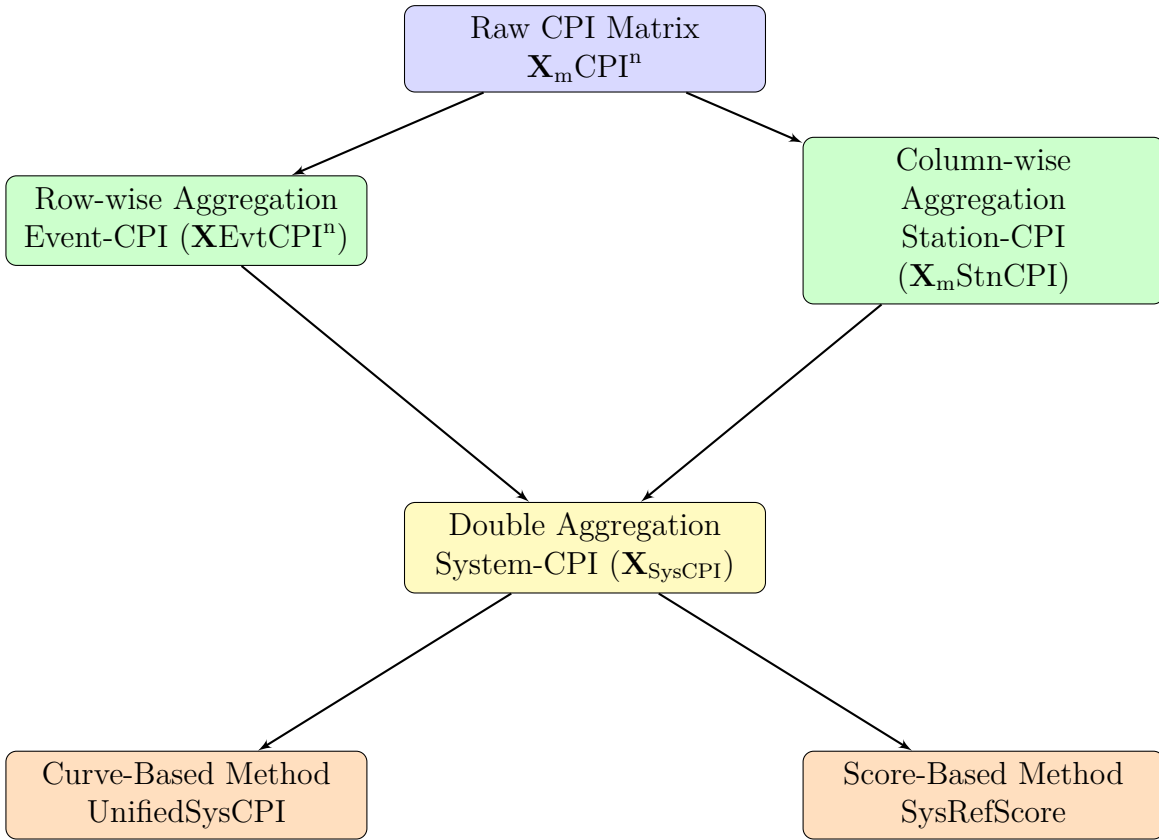


Figure 4.2: Aggregation pipeline from event–station matrix to System-CPI

Chapter 5

Multi-Infeed HVDC System Analysis Using Extended CPIs

This chapter applies the CPI framework to *multi-infeed* HVDC networks. Building on the per-unitization and aggregation tools of Chapter 4, we evaluate voltage and frequency performance across three bipoles and multiple AC-fault locations. By quantifying post-fault behaviour with consistent, system-level indices, the framework supports both diagnostic insight (e.g., converter’s control robustness and worst-case contingencies) and comparative planning (e.g., ranking topology and control options).

Chapter 5 Overview

Chapters 2–4 progressed from CPI theory and ISE selection to PSCAD-based controller tuning and a system-level CPI toolbox for single-infeed links. Chapter 5 extends that concept to the *multi-infeed* arena where power-sharing, voltage support, and frequency stability become strongly coupled across geographically dispersed converter stations. The same

ISE-based metrics are now applied simultaneously to all three bipoles—and to every AC fault location— aggregated over all fault locations, identify worst-case contingencies, and benchmark and rank alternative design options.

Scope of Chapter 5

- §5.1 strategically defines the fault-contingency set and the measurement points for the CPI framework; the choices are minimal yet representative.
- §5.2 analyses *DC-power* and *frequency* CPIs in a three-bipole network, showing how fault location influences power swings, frequency excursions, and their correlation.
- §5.3 develops *converter-station* and *bipole-level* voltage CPIs, introduces the Voltage-Multi-Infeed Interaction Performance Index (MIPI) matrix, and quantifies local–remote coupling through MIPI aggregation.
- §5.4 introduces the frequency–voltage *Event–CPI characteristic curve* for the three-bipole case and defines the *UnifiedSysCPI*—a triple-aggregated metric (across measurement stations, fault events, and both voltage and frequency) that also ranks individual contingencies by their voltage (y-axis) and frequency (x-axis) severities.
- §5.5 generalises the critical-clearing-time concept via a two-dimensional (fault-duration, fault-impedance) sweep, derives the LVRT boundary for the reference topology, and introduces the scalar *LVRT-Capability Area* for concise resilience benchmarking.

Together these sections transform the single-link CPI framework of Chapter 4 into a comprehensive *Multi-Infeed HVDC Performance Toolkit* that will underpin the comparative studies and planning guidelines presented in Chapter 6.

5.1 HVDC Multi-Infeed Simulation Setup

This study evaluates CPIs for DC power, frequency, and voltage in a three-bipole multi-infeed network. For reproducibility and to avoid redundant channels, we specify both the *fault-location set* n and the *measurement points* m used to form $\mathbf{X}_m\text{CPI}^n$.

5.1.1 Fault-Contingency Location (n) Setup:

The EMT event set comprises solid three-phase, six-cycle AC faults applied at converter buses on both rectifier- and inverter-side terminals. The fault-location index set is $\mathcal{N} = \{\text{BP1Rect}, \text{BP2Rect}, \text{BP3Rect}, \text{BP1\&2Inv}, \text{BP3Inv}\}$. Each CPI is evaluated over a 5 s post-fault recovery window.

5.1.2 Measurement Points (m) Selection

The choice of m follows the physics of each variable and the goal of minimizing duplication while preserving representativeness:

Voltage CPIs ($\mathbf{V}_m\text{CPI}^n$): local phenomenon. Voltages are monitored at each converter PCC; accordingly, m runs over the same station buses used for fault locations (i.e., the converter terminals covered by $\mathcal{N}$; $m \in \mathcal{N}$). This captures station-specific voltage behaviour and sensitivity to local SCR, filters, and reactive compensation.

Power CPIs ($\mathbf{P}_m\text{CPI}^n$): corridor delivery. DC power is monitored at the *receiving* end of each bipole, with $m \in \{\text{BP1}, \text{BP2}, \text{BP3}\}$. Rectifier and inverter powers within a bipole remain nearly equal during transients (differences reflect losses and short-term DC

energy exchange), so measuring both ends would duplicate information without altering ISE-based rankings. Receiving-end monitoring emphasizes delivered power to the load centers. Using bipole identifiers(e.g. $BP\#$) therefore avoids redundancy, keeps notation compact, and emphasizes corridor-level behaviour in the multi-infeed setting.

Frequency CPIs ($f_m\text{CPI}^n$): area-coherent variable. Frequency is treated as an area-coherent quantity and measured at representative AC zones on the rectifier and inverter sides, with $m \in \{\text{Rect}, \text{Inv}\}$. In Manitoba Hydro Three-Bipole system, stations within each area are strongly coupled, so frequency behaves as an area-wide (nearly global) variable. A single well-chosen bus per area captures the dominant dynamics while keeping the analysis lean and reproducible.

Therefore, the choice of m in a multi-infeed context is intentionally made to be case-dependent and flexible, guided by the study objective and system topology. In this work, m is selected to be minimal yet representative for both power and frequency CPIs, ensuring that key dynamics are captured without unnecessary redundancy or computational burden.

With n and m defined, the next section present DC-power CPIs and frequency CPIs for the multi-infeed case, followed by their CPI-based correlation analysis.

5.2 DC Power and Frequency CPI in a Multi-Infeed HVDC System

This section examines DC power and AC frequency responses to rectifier- and inverter-side faults in the Manitoba Hydro three-bipole multi-infeed network. Building on the measurement definitions in Section 5.1, we proceed in three steps: first, DC-power CPIs; second,

frequency CPIs; and third, their coupling via a CPI-based correlation analysis.

5.2.1 Power Fluctuations in Multi-Infeed HVDC

Table 5.1 summarizes DC-power responses for five solid three-phase fault locations: the rectifiers of Bipoles 1–3 (**BP1Rect**, **BP2Rect**, **BP3Rect**), the shared inverter for Bipoles 1 & 2 (**BP1&2Inv**), and the Bipole 3 inverter (**BP3Inv**). For each contingency n (first column), the per-unit power CPIs for Bipoles 1–3 ($\mathbf{P}_{\text{BP1}}\text{CPI}^n$, $\mathbf{P}_{\text{BP2}}\text{CPI}^n$, $\mathbf{P}_{\text{BP3}}\text{CPI}^n$) are listed, followed by the event-level aggregate $\mathbf{PEvtCPI}^n$.

Table 5.1: System-, Station-, and Event-Level Power CPI Results— $\mathbf{P}_m\text{CPI}^n$

n= Fault Conv.	$\mathbf{P}_m\text{CPI}^n$			$\mathbf{PEvtCPI}^n$
	$m = \text{BP1}$	BP2	BP3	
BP1 Rectifier	1.563	0.818	1.137	2.099
BP2 Rectifier	0.361	2.839	2.028	3.507
BP3 Rectifier	0.272	2.256	2.035	3.050
BP1&2 Inverter	1.893	2.877	2.326	4.155
BP3 Inverter	1.118	2.871	2.325	3.860
$\mathbf{P}_m\text{StnCPI}$	1.041	2.332	1.970	$\mathbf{P}_{\text{SysCPI}} = 3.334$
$\mathbf{P}_m\text{StnRefScore}$	100.0%	44.7%	52.9%	—

Per-unit entries $\mathbf{P}_m\text{CPI}^n$.

Row header = fault location n ; column header = monitoring station $m \in \{\text{BP1}, \text{BP2}, \text{BP3}\}$.

Green = Station-CPI\RPS ($\mathbf{P}_m\text{StnCPI} \setminus \mathbf{P}_m\text{StnRefScore}$); Yellow = fully aggregated System-CPI ($\mathbf{P}_{\text{SysCPI}}$).

By examining the largest and smallest values of $\mathbf{P}_m\text{CPI}^n$, one can readily identify the most severe and mild post-fault power variation measured at m under the contingency n . As shown in Table 5.1, the smallest individual station CPI value of 0.818 occurs at BP2 under a BP1 rectifier fault, whereas the largest of 2.877 arises at BP2 during a Dorsey common-bus

fault (BP1&2 inverter fault). These entries illustrate the localized range of power fluctuations across the multi-infeed system. Event-level aggregates convey system-wide severity more directly: the most severe contingency is BP1&2Inv with $\mathbf{PEvtCPI}^{\text{BP1\&2Inv}} = 4.155$, while the mildest is BP1Rect with $\mathbf{PEvtCPI}^{\text{BP1Rect}} = 2.099$. Together, these extremes define the envelope of multi-infeed power deviation under fault conditions, while the composite system-level value of 3.334 serves as a concise summary of overall resilience.

Suppose Bipole 1 (the system under prospective upgrade) has the reference StnCPI of 1.041. Then Bipoles 2 and 3 achieve 44.7% and 52.9% of Bipole 1's power recovery performance, respectively. This relative comparison highlights the extent to which the proposed Bipole 1 offers superior power stability benefits over the other two bipoles within the multi-infeed HVDC system.

5.2.2 Frequency Variation in Multi-Infeed HVDC

Although rectifier and inverter stations are decoupled through the HVDC link, faults originating at one side of the converter station can still induce frequency disturbances at remote stations. This effect arises from the temporary power deficit on the DC link following an AC fault. Table 5.2 summarises the per-unit frequency CPIs $\mathbf{f}_m\text{CPI}^n$, the row-wise event indices $\mathbf{fEvtCPI}^n$, the column-wise Station-CPIs $\mathbf{f}_m\text{StnCPI}$, and the system index $\mathbf{f}_{\text{SysCPI}}$.

Rectifier vs. inverter frequency asymmetry: The rectifier terminals of Bipoles 1–3 are connected to a remote generation collector system characterized by low local load and dominant hydro-based generation with slow governor dynamics. When an AC fault curtails power flow through the rectifier, the sudden *surplus* of mechanical input causes a comparatively steep frequency rise that is not immediately damped. The inverter terminals, by contrast,

are embedded in the main interconnected grid where inertia is higher and primary reserves are faster. This asymmetry leads to significantly larger and more persistent frequency deviations at the rectifiers, with rectifier-side CPIs (e.g., $f_{Rect}CPI$) exceeding inverter-side values by a factor of four to five. As shown in Table 5.2, this results in a Station-CPI of 0.618 for the rectifier and only 0.117 for the inverter.

Weight Adjustment to Restore Score Balance: If equal station weights were applied when computing the system-level frequency index ($fEvtCPI^n$), the rectifier side would dominate the result due to its disproportionately large excursions—masking the inverter’s contribution to system resilience. To address this imbalance, a non-uniform weighting scheme is adopted in which the rectifier and inverter are assigned frequency-specific weights of $W_{f_{rect}} = 0.2$ and $W_{f_{inv}} = 0.8$, respectively. This adjustment moderates the influence of extreme rectifier deviations and ensures that both ends contribute more evenly to frequency performance assessments.

As with the power CPI analysis, the worst fault contingencies for frequency can be identified by the maximum values of $fEvtCPI$. The largest *rectifier* frequency Event CPI level is 0.295, while the largest *inverter* frequency Event CPI value is 0.444. These “worst” contingencies indicate fault scenarios with more severe frequency deviations, which may increase the risk of over- or under-frequency issues in affected regions and thus warrant closer investigation from a protection and control perspective.

5.2.3 Power-Frequency CPI Correlation

The power recovery performance represented by the CPI value can directly impact the rectifier and inverter AC interconnected system frequency excursion. Figure 5.1 illustrates a

Table 5.2: System-, Station-, and Event-Level Frequency CPI Results— $\mathbf{f_mCPI^n}$

$\mathbf{n=}$ Fault Location	$\mathbf{f_mCPI^n}$		$\mathbf{fEvtCPI^n}$
	$m = \text{Rect}$	$m = \text{Inv}$	
BP1 Rectifier	0.350	0.046	0.162
BP2 Rectifier	0.624	0.105	0.295
BP3 Rectifier	0.469	0.099	0.228
BP1&2 Inverter	0.879	0.232	0.444
BP3 Inverter	0.769	0.104	0.356
$\mathbf{f_mStnCPI}$	0.618	0.117	$\mathbf{f_{SysCPI} = 0.297}$
$\mathbf{f_mStnRefScore}$	19%	100%	—

Per-unit entries $\mathbf{f_mCPI^n}$.

Row header = AC fault location n ; column header = monitored terminal $m \in \{\text{Rect}, \text{Inv}\}$.

Green = Station CPI/RPS ($\mathbf{f_mStnCPI}$, $\mathbf{f_mStnRefScore}$); Yellow = System CPI ($\mathbf{f_{SysCPI}}$).

Red and blue cells highlight worst-case entries for emphasis.

positive correlation between $\mathbf{PEvtCPI^n}$ (p.u.) and $\mathbf{fEvtCPI^n}$ (p.u.) across five fault scenarios (BP1Rect, BP3Rect, BP2Rect, BP3Inv, BP12Inv). Each data point represents a specific fault scenario, labeled by its location at n . A clear positive trend is evident: Larger transient power losses due to AC faults correspond to more pronounced frequency excursions, as indicated by higher $\mathbf{fEvtCPI^n}$ values. Notably, Bipole 2 faults—whether at the rectifier or inverter station—exert the greatest negative impact on overall frequency recovery, underscoring the need for detailed contingency and protection analysis of Bipole 2 in the later design stage.

Through this combined analysis of power and frequency CPIs, critical contingency events can be *identified* for system operation and frequency study planning studies; and this joint view also provides a compact sanity check that the power-to-frequency coupling is captured consistently by the CPI framework.

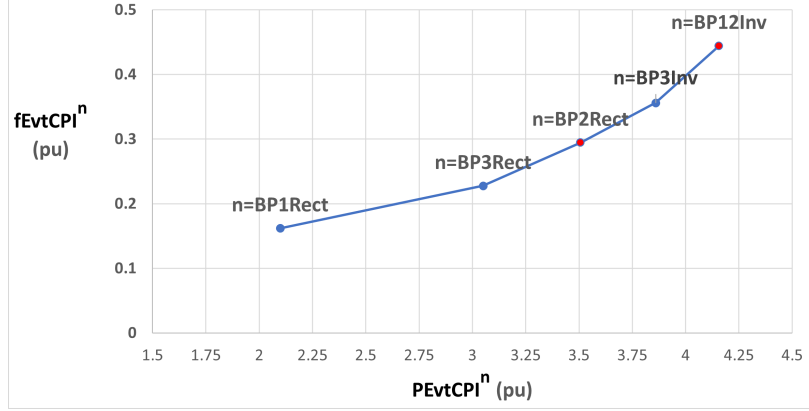


Figure 5.1: Relationship between PEvtCPI and fEvtCPI

5.3 Converter Station Voltage CPI in a Multi-Infeed System

In contrast to frequency-related CPIs, which can be grouped into rectifier-side and inverter-side metrics (Section 5.2), voltage responses at each converter station can vary significantly depending on the local dynamic voltage support. Consequently, separate voltage CPIs must be calculated for every station. This section interprets the station–event voltage-CPI matrix, identifies the most severe contingencies, and relates vulnerable stations to their $V_{mStnCPI}$ and $V_{mStnRefScore}$.

5.3.1 System-, Station-, and Event-Level Voltage CPIs in a Multi-Infeed System

In the studied model, there are five converter stations—three rectifiers and two inverters—yielding a 5×5 matrix of voltage CPI data. Each row represents an AC fault location at

converter 'n', while columns indicate the station where the voltage is measured at 'm' station. The diagonal elements are highlighted in gray to indicate the 'local fault–local measurement' scenario, which often yields the highest voltage deviation at that particular station.

Table 5.3 summarizes the voltage CPIs at each rectifier and inverter station under five fault conditions. The *last column* of the table reports the Event-level voltage CPI (V_{EvtCPI}), capturing the overall severity of voltage fluctuations triggered by a particular fault.

Worst event (row-wise): The **worst-case contingency** occurs when a fault is applied at the Bipole 2 Rectifier (BP2Rect.), where V_{EvtCPI} reaches 4.162. Geographically and electrically, Bipole 2 lies near the network's center, so a fault there strongly couples with other rectifiers and propagates to remote inverters via the DC link.

Most vulnerable station (column-wise): To evaluate *station-based* voltage stability, the StnCPI and corresponding score (StnRefScore) assess each converter station's voltage recovery under faults across all five converter buses. In this analysis, **Bipole 3 Rectifier** exhibits the poorest voltage recovery, with the largest StnCPI of 3.730 and a lowest station relative score of 56.2% relative to the new Bipole 1 VSC. Such a performance gap suggests that Bipole 3 Rectifier would benefit from additional dynamic voltage support—such as STATCOM or synchronous condensers—to reinforce its local voltage profile.

5.3.2 HVDC Bipole-Level Voltage CPI

In addition to station-based voltage CPIs (Table 5.3), a higher-level assessment can be performed by summing the rectifier and inverter voltage CPIs for each bipole. This yields

Table 5.3: System-, Station-, and Event-Level Voltage CPI Results— $\mathbf{V_mCPI^n}$

n= Fault Stn.	$\mathbf{V_mCPI^n}$					$\mathbf{VEvtCPI^n}$
	$m = \text{BP1Rect}$	BP2Rect	BP3Rect	BP12Inv	BP3Inv	
BP1 Rect.	6.210	2.072	2.072	0.771	0.746	3.108
BP2 Rect.	1.926	6.316	5.755	2.084	2.359	4.162
BP3 Rect.	1.069	3.458	6.120	1.631	1.942	3.376
BP1&2 Inv.	0.650	1.783	2.329	6.448	5.083	3.910
BP3 Inv.	0.631	1.780	2.377	5.062	6.524	3.934
$\mathbf{V_mStnCPI}$	2.097	3.082	3.730	3.199	3.331	$\mathbf{V_{SysCPI} = 3.698}$
$\mathbf{V_mStnRefScore}$	100.0%	68.0%	56.2%	65.6%	63.0%	—

Per-unit entries $\mathbf{V_mCPI^n}$.

Row header = AC fault location n ;

column header = monitored station $m \in \{\text{BP1rect}, \text{BP2rect}, \text{BP3rect}, \text{BP12inv}, \text{BP3inv}\}$.

Text red colors highlight max-stressed terminal; blue highlight the worst event.

an overall bipole-specific voltage CPI defined by:

$$V_{\text{BP}_i} = V_{\text{BPrect}_i} + V_{\text{BPinv}_i}, \quad (5.1)$$

where i denotes the HVDC bipole number. Table 5.4 presents these aggregated results in a multi-infeed context. The table has been augmented to indicate each bipole's converter technology: Bipole 1 implemented the VSC technology and serves as the proposed modernization target, while Bipoles 2 and 3 represent existing LCC systems. In this study, Bipole 1 is treated as the reference due to its superior voltage dynamic performance under faulted conditions. As seen in the Station-CPI and StnRefScore rows, Bipole 1 achieves the best overall voltage recovery, with Bipole 2 and Bipole 3 reaching only 84.3% and 75.0% of its performance, respectively.

These bipole-level results demonstrate that the LCCs in Bipole 2 and Bipole 3 experi-

Table 5.4: HVDC Bipole-Level Voltage CPI Summary by Converter Technology

Fault Location n	Voltage CPI: $V_m \text{CPI}^n$		
	$m = \text{BP1 (VSC)}$	$m = \text{BP2 (LCC)}$	$m = \text{BP3 (LCC)}$
BP1 Rectifier	6.982	2.843	2.819
BP2 Rectifier	4.009	8.400	8.114
BP3 Rectifier	2.700	5.089	8.062
BP1&2 Inverter	7.098	8.231	7.412
BP3 Inverter	5.692	6.841	8.900
$V_{\text{BP}_i \text{StnCPI}}$	5.296	6.281	7.061
$V_{\text{BP}_i \text{StnRefScore}}$	100.0%	84.3%	75.0%

ence more pronounced voltage deviations than the VSC in Bipole 1 under the studied fault scenarios. These results reflect the inherent voltage regulation advantages of VSC-based HVDC compared to LCC designs. Although station-level data remain essential for localized support decisions, the aggregated bipole-level CPI simplifies broad comparisons among different HVDC systems in the multi-infeed network.

5.4 Event–CPI Characteristic Curve and System Aggregation

The curve-based UnifiedSysCPI method introduced in Chapter 4 (Section 4.4.1) for the standalone single-infeed system is now extended to the three-bipole multi-infeed configuration.

Figure 5.2 plots, for the multi-infeed case, the frequency and voltage *event* CPIs as points in a two-dimensional plane: the x-axis is $f\text{EvtCPI}^n$ and the y-axis is $V\text{EvtCPI}^n$. These values come directly from the event-level columns of the earlier frequency and voltage CPI tables

(Table 5.2 and Table 5.3). Each point, therefore, corresponds to a specific AC fault location n in the three-bipole system. The coordinates ($\mathbf{fEvtCPI}^n, \mathbf{VEvtCPI}^n$) reveal the relative severity of frequency and voltage deviations for that contingency.

As discussed in Chapter 4, the distance from the origin to the final aggregation point (shown in red marker), computed after applying the V/f scale ratio of Eq. (4.7)–(4.8), yields the *UnifiedSysCPI* for the multi-infeed system. As a *triple-aggregated* metric, this scalar condenses measurements from all stations, contingency-weighted events, and both voltage and frequency into a planning-grade performance index; while the full cloud of event-level points is retained for quantified traceability. In Chapter 5, the curve-based *UnifiedSysCPI* is used to characterize a single multi-infeed system, preserving *event-level transparency* while providing a concise system score. The score-based method for *relative* comparison (system reference score) requires at least two alternatives and is therefore deferred to Chapter 6, where different ratings, topologies, and control modes are compared on the same footing.

Ranking and quantification: Beyond providing a single system score, the event distribution offers valuable diagnostic insight. A notable strength of the curve-based UnifiedSysCPI representation is that it reveals *both* the ranking and the magnitude of each contingency’s impact. Vertices positioned higher along the y -axis correspond to greater voltage deviations (higher $\mathbf{VEvtCPI}^n$), while those farther to the right along the x -axis indicate larger frequency excursions (higher $\mathbf{fEvtCPI}^n$). Using the aggregated event values, the voltage-severity ranking (worst to best) is: BP2 Rect. (4.162) > BP3 Inv. (3.934) > BP1&2 Inv. (3.910) > BP3 Rect. (3.376) > BP1 Rect. (3.108). On the other hand, the frequency-severity ranking is: BP1&2 Inv. (0.444) > BP3 Inv. (0.356) > BP2 Rect. (0.295) > BP3 Rect. (0.228) > BP1 Rect. (0.162). Because these coordinates are quantitative, the Euclidean distance from

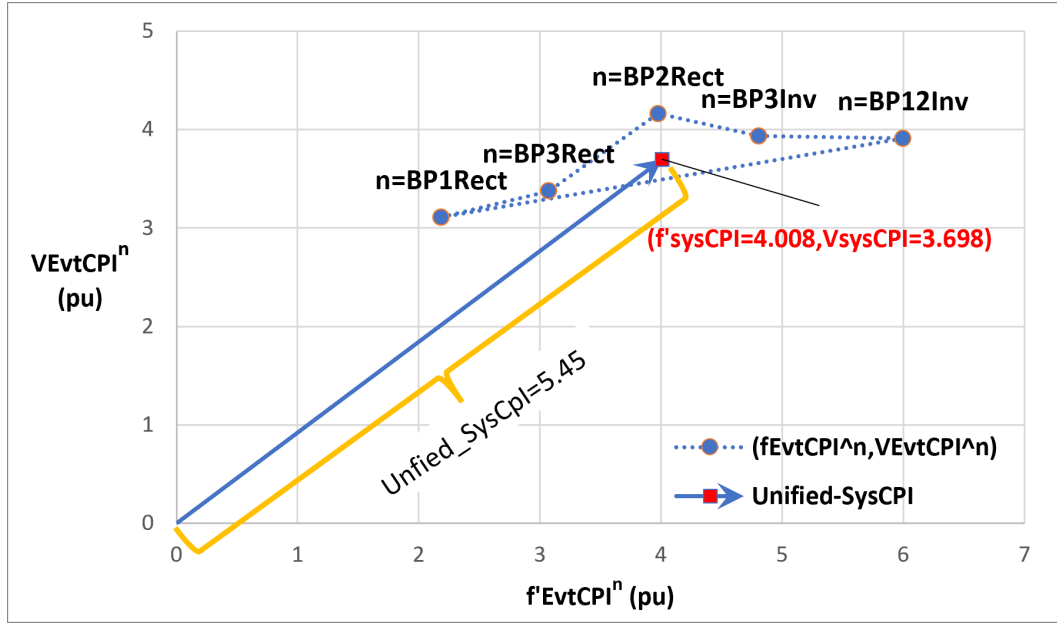


Figure 5.2: Multi-infeed HVDC: frequency–voltage event-CPI characteristic and system aggregate

the origin to each event point reflects the combined magnitude of its frequency and voltage impacts. This dual-axis view not only identifies the worst contingencies in each parameter but also expresses their relative severity in a directly comparable form.

5.5 Multi-Infeed HVDC Stability Boundaries

Having established the system’s performance under uniform three-phase, six-cycle solid faults (with fault type definitions previously introduced in Section 4.2), we now turn to investigate how variations in fault impedance and duration shape the system response, and how such changes manifest in the CPI framework. This section introduces a CPI-based simulation method to assess multi-infeed HVDC stability limits for both solid and high-impedance faults. The approach quantifies fault severity and determines the system’s ability

to ride through voltage depressions—analogous to, but more general than, the classical Critical Clearing Time (CCT) test.

5.5.1 CPI-Based Fault-Severity Assessment

As shown earlier (e.g., Section 5.4 and Figure 5.2), AC-fault *location* strongly conditions system-wide voltage and frequency excursions, which are compactly summarized by CPI metrics. We leverage this property to construct a scalar indicator of disturbance severity and to trace stability margins against varying fault parameters.

Conceptual Link to Critical Clearing Time: In traditional power system stability analysis, CCT identifies the maximum allowable fault duration before system instability occurs [115]. As discussed in Chapter 2, Sect. 2.1.4.2, traditional CCT assessments are typically limited to solid faults, assuming zero voltage throughout the fault duration. Here, this study proposes a more generalized LVRT-based approach by incorporating both *fault duration* and *fault impedance*, expanding the spectrum of evaluated fault conditions.

The proposed method mirrors the classical CCT test but generalizes it along two dimensions:

- (i) *fault duration* t_f is treated as a continuous parameter, and
- (ii) *fault impedance* Z_f is varied so as to impose specific retained(fault-on) voltage $V_{df}/V_0 \in [0, 0.8]$.

where V_{df} is the *voltage during the fault* (retained voltage) at base of rated value V_0 . By combining both parameters, we obtain a two-dimensional stability surface from which the system's LVRT margin can be read directly.

Sweeping $(t_f, V_{df}/V_0)$ yields a two-dimensional stability surface from which the low-voltage ride-through (LVRT) margin can be read directly. Systems that maintain LVRT at *longer* durations and *deeper* retained-voltage dips exhibit greater dynamic robustness.

These concepts are further extended in Chapter 6, where different HVDC topologies (e.g., VSC–VSC vs Mixed LCC–VSC), ratings (2800 MW vs 2000 MW), and control strategies are benchmarked using the same CPI-based framework to assess their relative Low-Voltage-Ride-Through (LVRT) capabilities.

5.5.2 LVRT Test Matrix and Simulation Setup

LVRT Test Matrix: To evaluate LVRT capability systematically, a comprehensive grid disturbance test matrix was constructed involving a total of 288 unique fault scenarios. These scenarios are formed by combining:

- **32 Fault Durations**, ranging from 5 to 160 cycles in 5-cycle increments ($t_f = 5$ –160 cycles, $\Delta t = 5$ cycles),
- **9 Fault Impedance**, each calibrated to achieve specific retained voltage levels from 0% to 80% of retained voltage in 10% increments ($V_{df}/V_0 = \{0, 0.1, \dots, 0.8\}$).

Impedance Calibration In determining the fault impedance values for each retained voltage level, an iterative tuning process was employed. By adjusting the impedance until the target retained voltage magnitude was observed (e.g., 10%, 20%, ... 80%), the corresponding impedance values were catalogued. In other words, for each V_{df}/V_0 level an iterative search determines the corresponding Z_f that satisfies

$$\left. \frac{V_{df}}{V_0} \right|_{Z_f} = k, \quad k \in \{0, 0.1, \dots, 0.8\},$$

while maintaining the pre-fault operating point unchanged.

Stability Assessment Procedure For each impedance level, simulations were performed while gradually increasing the fault duration. The critical fault duration —defined as the longest fault the system can endure before instability arises—was recorded for each case. This duration approximates the system’s CCT under retained voltage conditions, offering a broad characterization of system robustness.

For a fixed Z_f , t_f is increased stepwise until the first instance of instability is detected. The corresponding $t_{f,\text{crit}}$ approximates the CCT for that impedance. Repeating the sweep for every Z_f yields the LVRT boundary

$$\mathcal{B}_{\text{LVRT}} = \{(V_{\text{df}}/V_0, t_{f,\text{crit}})\},$$

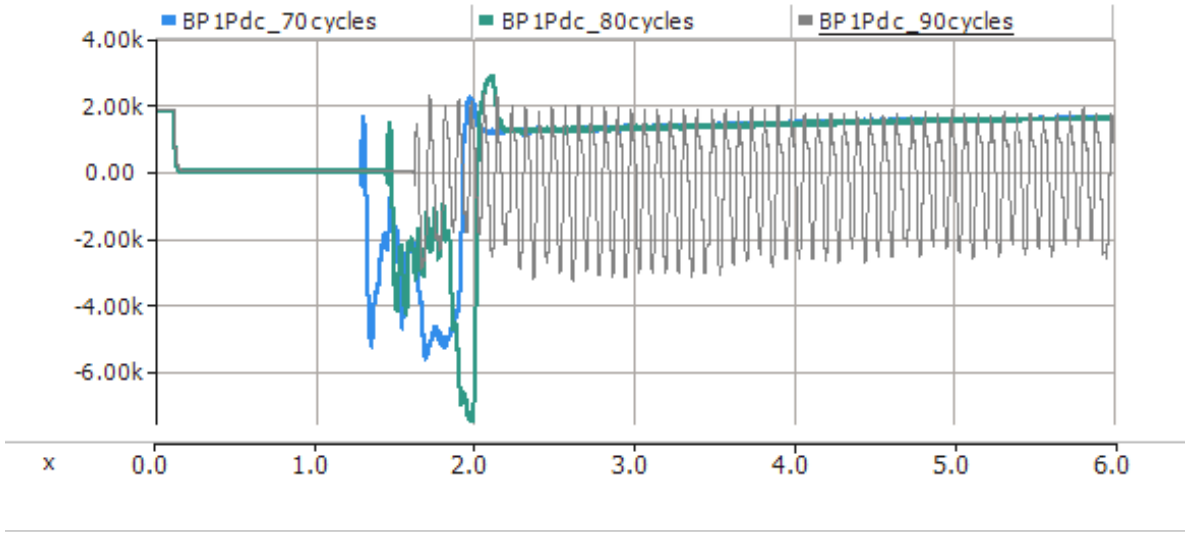
against which alternative HVDC configurations (e.g. VSC/VSC, LCC–VSC Mixeds, different ratings or control modes) are analyzed in Chapter 6. A topology that tolerates longer $t_{f,\text{crit}}$ or deeper voltage depressions is deemed more resilient.

5.5.3 Determination of the LVRT Stability Boundary

In multi-infeed HVDC systems, when increasing the fault duration under a fixed fault impedance, a critical point eventually emerges beyond which the system becomes dynamically unstable. At this boundary, the system exhibits significant oscillations in voltage and frequency, and generator rotor angle divergence may occur, indicating the loss of synchronism. This phenomenon can be illustrated using the Bipole 1 HVDC system subject to a solid three-phase fault applied at the inverter station.

Figure 5.3 presents the real power at the DC terminal of Bipole 1 for three fault durations:

70 cycles (blue), 80 cycles (green), and 90 cycles (black). The simulation results show that with a fault duration of 70 cycles, the system recovers to a steady operating point. At 80 cycles, although small transients are observed, the retained power stabilizes. However, when the fault duration is extended to 90 cycles, the system fails to recover, and persistent power oscillations ensue, indicating the system has become unstable. This marks the 80 cycles CCT for the given zero-voltage condition.



Blue: 70 cycles; Green: 80 cycles; Black: 90 cycles.

Figure 5.3: Bipole 1 HVDC Power Transient Response with 3-Phase Solid Fault at Inverter Bus: DC Power (P_{dc}) vs. Time (s)

Although visually inspecting waveform plots like those in Figure 5.3 provides insight into system dynamics, this method is labor-intensive and subjective—especially given the large number of monitored signals. Additionally, different signals may yield conflicting conclusions regarding system stability. Thus, a systematic and quantitative approach is necessary.

Figure 5.4 introduces a more efficient stability assessment method using the system-

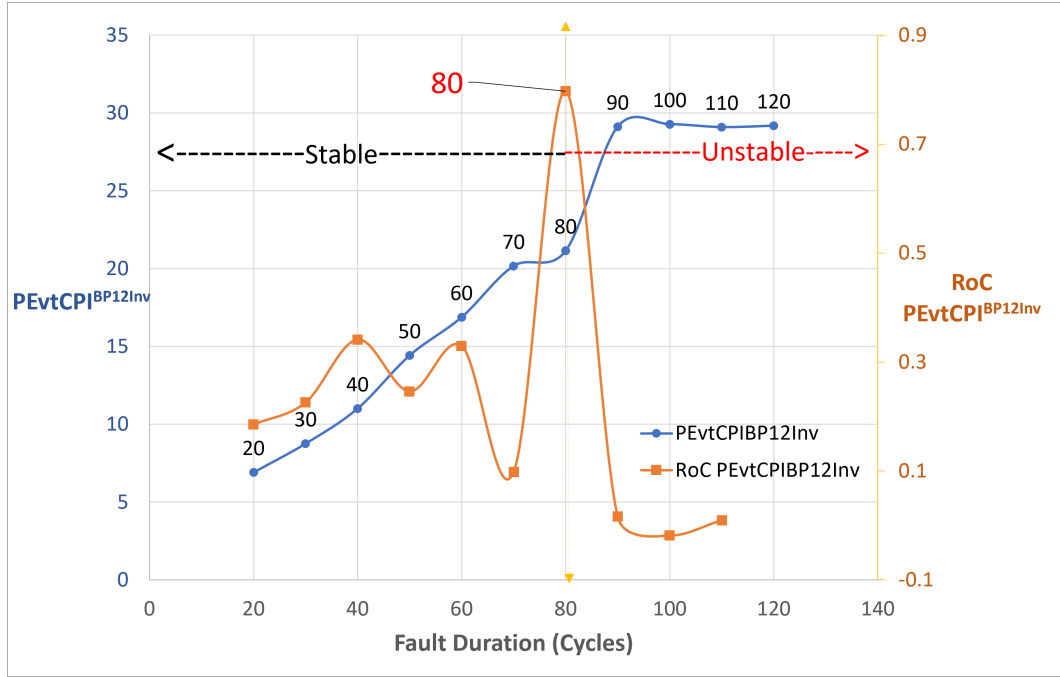


Figure 5.4: System-level HVDC CPI and its rate of change under increasing fault duration.

level control performance index (CPI), specially plots the Evt-level P_{EvtCPI} (blue, left axis) together with its rate of change (orange, right axis). The blue curve represents the value of P_{EvtCPI}^n cross-fault durations ranging from 20 to 120 cycles. As the fault duration increases, P_{EvtCPI}^n grows gradually, indicating deteriorating but still recoverable dynamic behavior. However, at 90 cycles, a sudden and sharp increase is observed—signifying a transition from stability to instability. This abrupt change coincides with the waveform instability observed in Figure 5.3, validating the correspondence between high CPI and system collapse.

To automate the identification of this transition point, the rate of change (RoC) of P_{EvtCPI} is computed and plotted as the orange curve. The RoC peaks significantly at 80 cycles, which precedes the system's loss of stability. This suggests that the maximum

RoC can be used as a reliable indicator of the system's stability threshold. Accordingly, the system's LVRT capability under zero-voltage conditions is determined to be 80 cycles. Beyond this point, the risk of instability becomes critical.

This RoC-based CPI boundary detection aligns with prior findings such as in [116], which proposed the use of CPI rate of change in protection schemes and fast reclosing logic. The methodology presented here generalizes this idea into a robust screening method for multi-infeed HVDC systems, providing an automated predictor of $t_{f,crit}$ without subjective waveform inspection.

5.5.4 Low-Voltage Ride-Through (LVRT) Capability Evaluation

In multi-infeed HVDC systems, it is essential to evaluate the system's stability margin during the planning phase—particularly to identify the boundary beyond which instability occurs. This boundary, represented by the system's *low-voltage ride-through* (LVRT) capability, informs the resilience of a given HVDC configuration under severe disturbances.

Previously, in Section 5.5.3, the critical clearing point for a zero-voltage fault was determined by tracking the rate of change (RoC) in the system-level control performance index (PEvtCPI). This concept can be generalized to evaluate LVRT capability under *non-zero* retained voltages caused by high-impedance faults.

Figure 5.5 illustrates the LVRT boundary across varying retained voltages (V_{df}) from 0 to 0.8 pu and fault ride-through (FRT) durations. The red curve delineates the maximum allowable fault duration at each retained voltage level. The blue shaded region below this curve indicates the stable operating region for the studied system, which consists of a 2800 MW VSC–VSC topology with the inverter in reactive power control (Q) mode.

To quantitatively assess this ride-through resilience, the area under the LVRT curve—termed

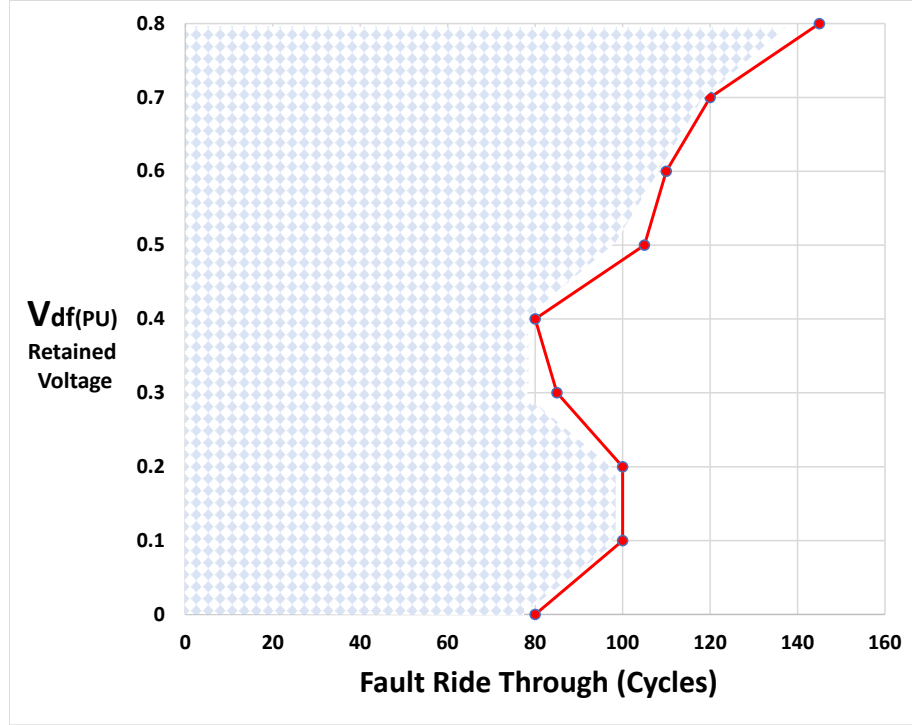


Figure 5.5: LVRT Boundary for 2800MW VSC-VSC Multi-Infeed HVDC: Retained Voltage (pu) vs. Fault Ride-Through Duration (cycles)

the *LVRT Capability Area* (LVRTCA)—is computed. Using the trapezoidal rule over discrete fault points, the LVRTCA is given by:

$$\text{LVRTCA} = \sum_{i=1}^{n-1} \frac{C_i + C_{i+1}}{2} \cdot (V_{i+1} - V_i) \quad (5.2)$$

For a uniform voltage step size of $\Delta V = 0.1$ pu in this case, the equation simplifies to:

$$\text{LVRTCA} = \Delta V \left(\frac{C_1 + C_n}{2} + \sum_{i=2}^{n-1} C_i \right) \quad (5.3)$$

where C_i represents the critical fault duration (in cycles) at retained voltage V_i , and n is the total number of sampled points.

For the studied configuration, the calculated LVRTCA equals 81.25 cycles·pu. This scalar index allows for straightforward comparison of fault-tolerance capability across multiple HVDC alternatives. In Chapter 6, Section 6.5 extends this analysis by benchmarking LVRTCA across different converter topologies, ratings, and control strategies, thus supporting informed decision-making during the planning stage.

Chapter-5 Summary

This chapter has extended the CPI methodology from the single-infeed context of Chapter 4 to a realistic three-bipole multi-infeed grid and has demonstrated how event, station, and system indices support ranking, diagnosis, and stability-limit definition. The main findings are:

- 1) **Coupled power–frequency behaviour** Across fault locations, a clear positive correlation emerged between the event-level power and frequency indices, $\mathbf{PEvtCPI}^n$ and $\mathbf{fEvtCPI}^n$, linking larger delivered-power deficits to stronger frequency excursions.
- 2) **Identification of critical stations** Converter locations that dominate system stress were revealed by *Event CPI* and *Station CPI*: (i) the shared BP1&2 inverter is the worst frequency-contingency, (ii) the BP2 rectifier sets the voltage worst-case, and (iii) the BP3 rectifier shows the poorest Station-CPIvoltage score ($\text{StnRefScore} = 56\%$).
- 3) **Generalised stability boundary** A two-dimensional sweep of fault duration and impedance produced an LVRT surface from which a single *LVRT-Capability Area* (81.25 cycles · pu for the reference 2800 MW VSC-VSC grid) was extracted, providing a compact, waveform-independent resilience metric.

- 4) **Automated CCT detection** The peak rate-of-change of the system CPI reliably located the transition to instability (80 cycles at zero retained voltage), removing the need for subjective waveform inspection.

These results confirm that the extended CPI framework provides a scalable, data-driven basis for comparing multi-infeed HVDC options. Chapter 6 applies these instruments to cross-technology comparisons under varied control modes, ratings, and grid strengths.

Chapter 6

Comprehensive Analysis and Discussion

Chapter 6 Overview

Building on the step-wise progression established in the previous chapters, Chapter 6 draws the thesis to its natural culmination:

- Ch. 2** developed the *theoretical* foundations of Control-Performance Indices (CPIs) and adopted the *Integral-Squared-Error* as the principal metric;
- Ch. 3** embedded that metric in the optimization to tune the individual converter controllers and to standardize a 20s disturbance–recovery test window;
- Ch. 4** generalised the CPI concept from *converter-centric* analysis to a *single-infeed system* by introducing per-unitisation, fault/station weighting, and composite voltage–frequency scores;

Ch. 5 extended the same tools to a *three-bipole multi-infeed grid*, ranked alternative topologies, ratings, and control modes, and derived an RoC-based method for automatic LVRT boundary detection.

Whereas Chapters 3–5 demonstrated the CPI machinery on *specific* case studies, the present chapter (i) unifies those steps into a repeatable workflow, (ii) validates an online/off-line toolchain for routine EMT studies, and (iii) consolidates all previous findings into planning-ready guidelines and comparative dashboards.

Scope of Chapter 6

- §6.1 proposes a streamlined, seven-step CPI workflow from fault simulation through calculation, weighting, aggregation,
- §6.2 introduces an *online* PSCAD component and a *GUI-based* off-line post-processor, providing repeatable and auditable pipeline of processing CPI values and also slashing manual post-processing effort.
- §6.3 applies the workflow across alternatives, comparing voltage *StnRefScore* (§6.3.1), DC-power *StnRefScore* (§6.3.2), and power–frequency correlations (§6.3.3).
- §6.4 collates the two planning alternative approaches—*UnifiedSysCPI* and *SysRefScore* into a single dashboard, ranking six HVDC alternatives by topology, rating, and control mode.
- §6.5 revisits the RoC-CPI/LVRT-boundary method on four representative designs, converts the two-dimensional boundary into a scalar *LVRT Capability Area*, and highlights how voltage control mode delivers the largest ride-through margin.

- §6.6 positions the CPI toolkit alongside to established HVDC index families (SCR/E-SCR, VSF/MAP/CSI, MIIF/RF/UIF, CCT/Nadir), providing a screening bridge from CPI-based rankings to the existing planning practices.

Together, these sections transform the CPI toolbox from an academic proof-of-concept into a streamlined, industry-ready framework capable of benchmarking any future HVDC expansion scenario on a common, quantitative basis.

6.1 Streamlined CPI Analysis Workflow

In order to employ the CPI framework efficiently across diverse HVDC planning scenarios, a systematic approach is proposed. This streamlined method ensures that fault data is collected, processed, weighted, and finally composed into composite indices in a consistent, repeatable manner.

6.1.1 Proposed Workflow

The key steps of the proposed workflow are summarized below:

1. **System Setup and Fault Simulation** *Process*: Initialize the standalone or multi-infeed HVDC system, selecting the desired topology, rating, and control mode. Apply AC faults to each converter station (rectifier and inverter) per the study's contingency list.

Generated Data: Time-domain transient waveforms of **frequency, voltage, and DC power**.

2. **Time-Domain Data Collection** *Action*: Record system responses for the specified

post-fault time window (default five seconds; extend to ten seconds if slow-recovery dynamics are relevant to this study), capturing variations in frequency, voltage, and DC power.

Result: A dataset of raw transient waveforms suitable for CPI calculations.

3. **CPI Computation:** A structured CPI matrix for each station from Step 2, normalized into per-unit values for comparison; For each variable $X \in \{P, V, f\}$ and each fault-measurement pair (n, m) , compute the ISE-based CPI using the time-weight $w_t(t)$ from Chapter 4, then convert to per-unit as in §4.2.

Computed Values: a per-unit CPI matrix $\mathbf{X}_m \text{CPI}^n$ for each X .

4. **Weight Specification:** Define aggregation weights consistent with §4.3: station weights W_{X_m} , event weights W_{X_n} , and composition weights W_v, W_f (equal by default).

Deliverable: A standardized set of weights enabling consistent computation of CPI.

5. **Aggregate Indices :** Compute higher-level indices based on CPI values and weighting factors (§4.3.2–§4.3.3) :

- **StnCPI** (Station CPI)
- **EvtCPI** (Event CPI)
- **SysCPI** (Double-Aggregated CPI)

Aggregation outcome: ranked stations and contingencies plus a system index per variable that serve as inputs to Step 7's parameter composition (merging V and f into a single system metric).

6. **Visualization and Interpretation:** *Process:* Generate graphical representations to aid in analysis:

- **Event CPI Curve:** Plots Event frequency CPI (f_{EvtCPI}) vs. Event voltage CPI (V_{EvtCPI}).
- **Multi-Index Correlation:** Graphs such as P_{EvtCPI} vs. f_{EvtCPI} vs. V_{EvtCPI}
- **Bar Diagram of Station or System Reference Score:** bar charts to rank (i) converter stations within a single alternative and (ii) planning alternatives across the portfolio

Interpretation: Visual analytics to quantify and rank fault severity, identify location-specific vulnerabilities, and summarise overall performance at the station, event, and system levels.

7. **Composite Score and Comparison :** Fuse $\mathbf{f}_{\text{SysCPI}}$ and $\mathbf{V}_{\text{SysCPI}}$ via *UnifiedSysCPI* (curve-based, scaled by $R_{V/f}$, §4.4.1) or *SysRefScore* (score-based, §4.4.2) to produce a single headline metric for planning alternatives evaluation. *Final Measure:* Quantitative benchmarks for planners to compare different HVDC **control modes, ratings, and topologies**, facilitating informed decision-making.

To illustrate the structured process of CPI analysis, Figure 6.1 presents a streamlined workflow encompassing all key steps. This flowchart visually summarizes the sequential stages, from system setup and fault simulation to CPI computation, aggregation, and final composite index evaluation. By following this structured approach, HVDC planners can systematically analyze system performance under various fault scenarios and optimize configurations based on quantitative CPI-based metrics, and other utilities can apply the same workflow to investigate the resilience of their own networks in a consistent and comparable manner.

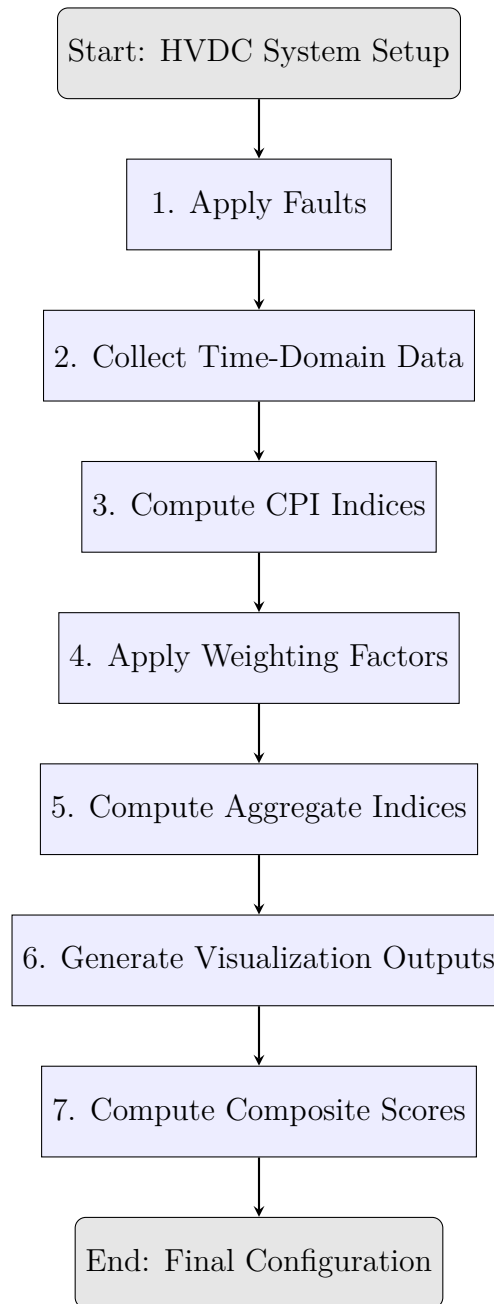


Figure 6.1: Streamlined CPI Analysis Workflow

6.2 CPI Data Measurements and Post-Processing Tool

Two routes are used to obtain CPI measurements: (i) *online* during EMT runs in PSCAD via a lightweight in-model module, and (ii) *offline* after the run from saved waveforms (PSCAD/RTDS) using Python (NumPy/SciPy). A GUI post-processing tool then ingests either source, applies consistent normalisation and study weights, performs the standard aggregations (StnCPI/EvtCPI/SysCPI), and produces composite metrics (*UnifiedSysCPI*, *SysRefScore*) and figures for comparison. The workflow is repeatable, auditable, and portable to other HVDC studies—standardised windows, scaling, weights, and outputs enable easy replication and extension. In practice, the PSCAD-embedded (online) option offers a simplified workflow suited for rapid checks or novice users, while the Python-based (offline) route provides more flexibility for advanced users who may wish to customise the post-processing algorithms.

6.2.0.1 CPI Data Measurement: Online vs Offline

Online refers to computing CPI signals *during* EMT simulations in PSCAD, whereas *offline* refers to computing them *after* the run from saved waveforms (PSCAD/RTDS) using Python (NumPy/SciPy).

Online (PSCAD module, measurement-only). This approach utilizes an online CPI calculation module within PSCAD, capable of computing CPI values dynamically during simulation runtime. The internal control logic of this module is illustrated in Figure 6.2. The fundamental concept involves specifying a pre-fault steady-state period, tracking the steady-state value (X_{ss}), and continuously comparing it against transient responses to compute

error signals. These error signals are subsequently integrated over time to derive key CPI metrics, including the Integral of Squared Error (ISE), Integral of Time-weighted Squared Error (ITSE), Integral of Absolute Error (IAE), and Integral of Time-weighted Absolute Error (ITAE), as defined in Chapter 2.

This built-in functionality allows CPI values to be obtained immediately upon completion of a PSCAD simulation run, facilitating rapid assessment of system performance. However, this construction is *measurement-only*: it performs no per-unitization, weighting, or station/event/system aggregation.

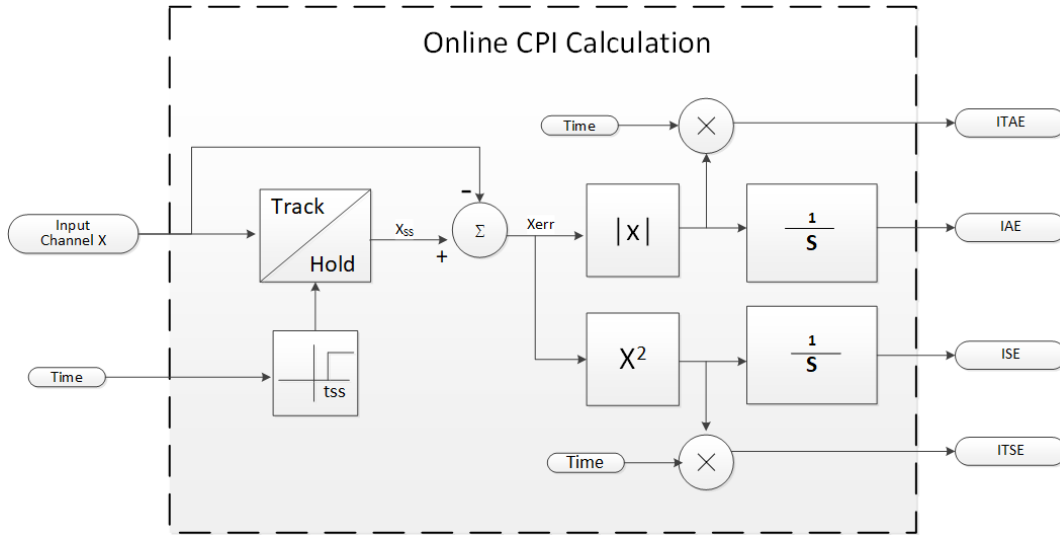


Figure 6.2: Online CPI Calculation Module in PSCAD

Offline (Python post-run computation): The same indices are computed from previously saved channels using vectorised NumPy operations and SciPy’s trapezoidal integrator: detect the pre-fault window to estimate X_{ss} , form $e(t)$, build $|e(t)|$, $e^2(t)$, $t|e(t)|$, $te^2(t)$, and integrate over the scaleable time window to obtain CPI scalars. This route avoids PSCAD module building and enables batch processing of legacy files without re-running PSCAD

cases.

6.2.0.2 Post-Processing Tool for CPI Computation

After the CPI computation, a *GUI-based post-processing tool* was developed to analyze CPI values offline from PSCAD or RTDS simulation results. This GUI ingests either (i) CPI measurements produced during EMT runs (online PSCAD module) or (ii) raw waveforms from saved simulations, and automates all steps *beyond measurement* (cf. workflow Steps 4–8). This tool automates multiple features of the CPI workflow described in Section 6.1.1, including:

- **CPI Computation:** Extracts frequency, voltage, and power data from simulation outputs and computes CPI values over a specified time window (When online measurement is absent).
- **Weight Specification:** Allows users to assign customized weighting factors for voltage, frequency, and fault scenarios.
- **Aggregate Indices:** Computes composite indices such as EvtCPI, StnCPI and SysCPI to evaluate overall system resilience.
- **Visualization and Interpretation:** Provides graphical representations of CPI results, including characteristic curves and correlation plots.

The advantage of the GUI tool is its ability to significantly reduce manual effort while minimizing human error. As shown in Figure 6.3, the interface enables users to process large datasets efficiently, ensuring user-friendly operation and enhanced reliability in CPI assessment.

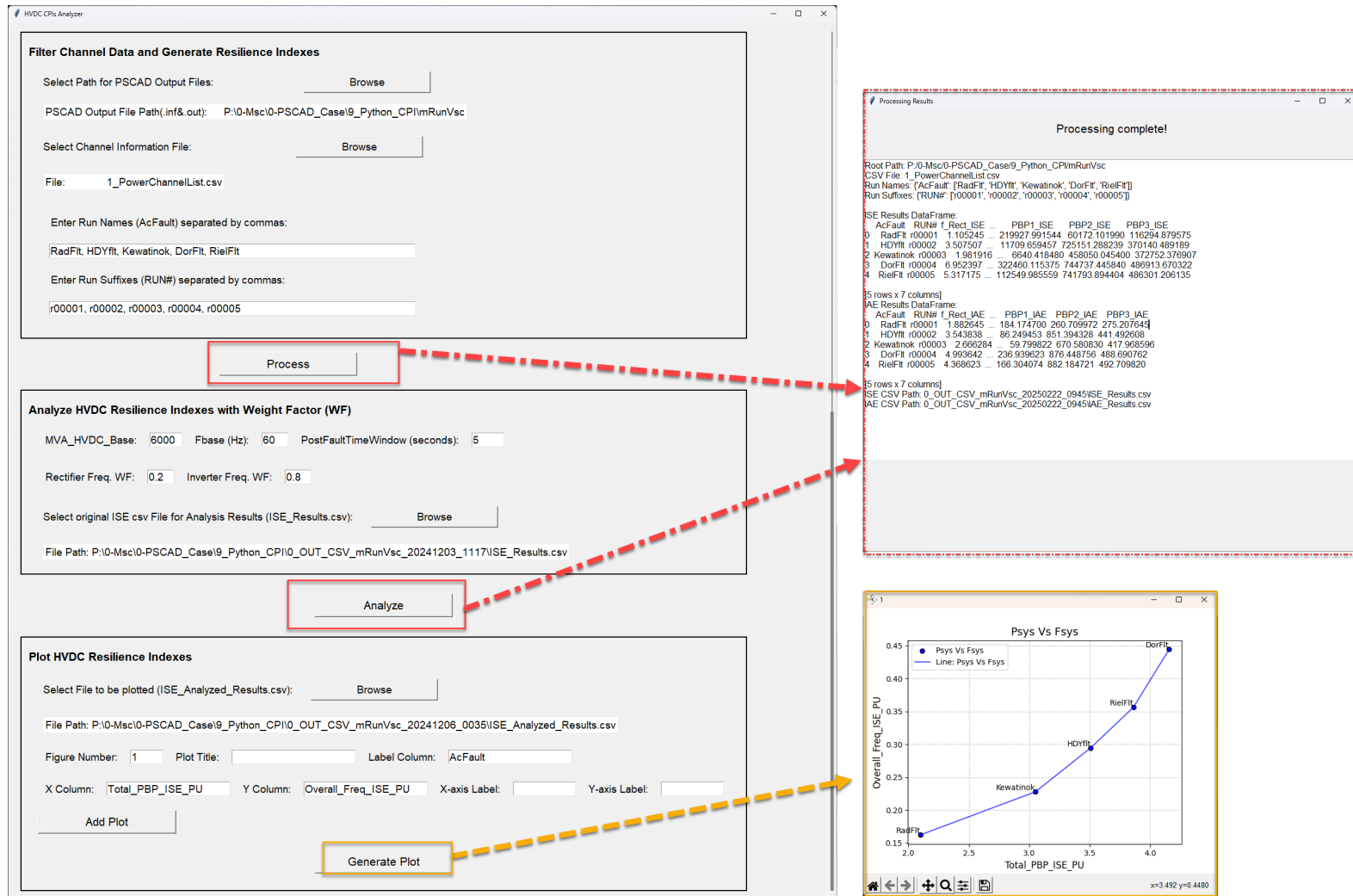


Figure 6.3: GUI-Based Offline CPI Post-Processing Tool

By adopting the *streamlined* CPI computation approach, this study establishes a robust, repeatable, and efficient framework for evaluating HVDC system performance.

6.3 Detailed Performance Analysis Under Multi-Infeed Scenarios

Whereas Chapter 5 applied the CPI framework to a single multi-infeed HVDC alternative, the present chapter broadens the scope by comparing multiple planning options with varying topologies, ratings, and control modes.

In the following sections, we present a comprehensive evaluation of multi-infeed HVDC performance under a range of operating scenarios and fault conditions. Building on the foundational CPI concepts from Chapters 4 and 5, we investigate key indicators such as *Station Performance scores* (StnRefScore), *voltage stability metrics*, and *power–frequency correlations* across multiple bipoles. By comparing different converter topologies, power ratings, and control modes, we aim to (i) identify specific bipoles or stations that exhibit slower post-fault recovery, (ii) quantify the impact of design choices of BP1 modernization project (e.g., VSC vs. LCC, AC-voltage vs. reactive-power control), and (iii) highlight potential co-ordination strategies for improving overall resilience. The subsequent subsections explore these aspects in detail, each focusing on a particular metric or viewpoint that illuminates the strengths and weaknesses of the candidate multi-infeed HVDC configurations.

6.3.1 Station- and Bipole-Level Voltage StnCPI/StnRefScore

We begin with station-granular voltage behaviour. The voltage response of each HVDC system can be assessed by examining the **Station CPI** (StnCPI) at the station level and then

aggregating rectifier/inverter contributions into a bipole-level **StnCPI**. Tables 6.1 and 6.2 summarise these metrics for three BP1 options—VSC–VSC (2800 MW), Mixed LCC–VSC (2800 MW), and VSC–VSC (2000 MW)—plus a sensitivity where the new VSC inverter switches from reactive-power control (Q mode) to AC-voltage control (V mode).

Table 6.1: Station-Level Voltage V_m StnCPI for BP1 Alternatives

BP1 Alternatives	VrectBP1	VrectBP2	VrectBP3	VinvBP12	VinvBP3
VSC2800(Q)	2.10	3.08	3.73	3.20	3.33
Mixed2800(Q)	2.21	3.12	3.74	3.25	3.43
VSC2000(Q)	2.24	3.10	3.75	3.22	3.39
VSC2800(V)	2.11	3.04	3.69	2.76	2.98

Table 6.2: Bipole-Level Voltage V_{BP_i} StnCPI (rectifier+inverter)

BP1 Proposed Configuration	VBP1StnCPI	VBP2StnCPI	VBP3StnCPI
VSC–VSC 2800 MW (Q mode)	5.30	6.28	7.06
Mixed LCC–VSC 2800 (Q mode)	5.47	6.37	7.18
VSC–VSC 2000 MW (Q mode)	5.46	6.32	7.14
VSC–VSC 2800 MW (V mode)	4.87	5.80	6.68

Station- and Bipole-Level Voltage StnRefScore

We convert V_m StnCPI to dimensionless V_m StnRefScore using BP1 VSC{VSC 2800 MW as the 100% reference. Figures 6.4 and 6.5 display station- and bipole-level voltage StnRefScores, respectively. Consequently, a higher StnRefScore indicates **faster** or **more stable** post-fault voltage recovery relative to this reference scenario.

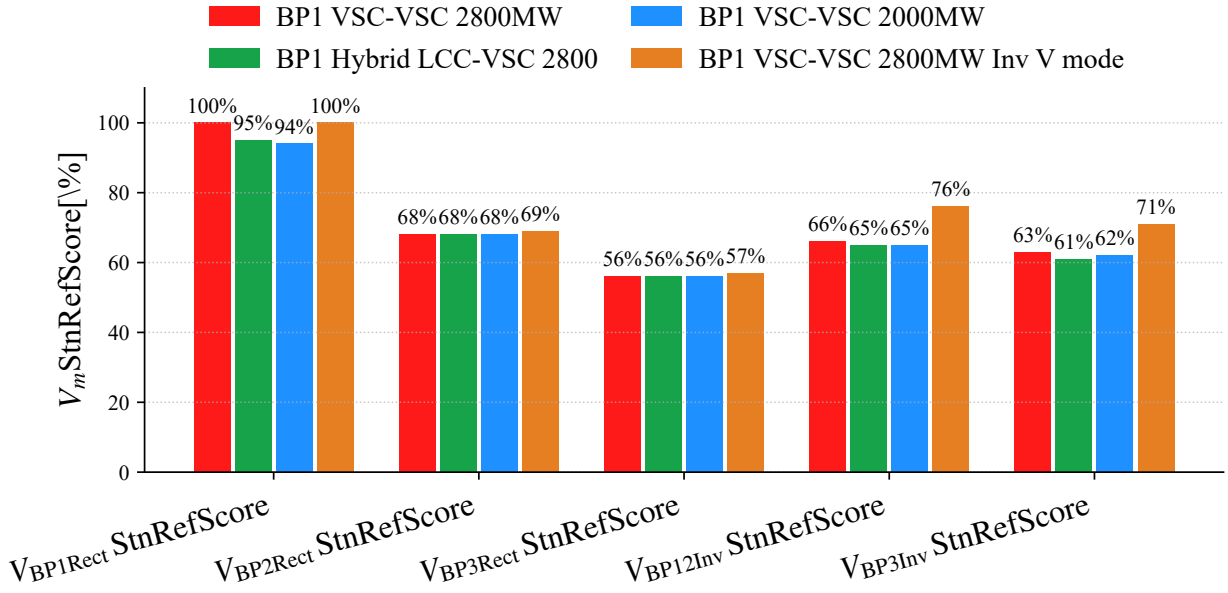


Figure 6.4: Voltage StnRefScore at each station for BP1 configurations

Station-Level Voltage CPI Insights:

- Control-mode leverage (inverter):** Switching the BP1 VSC inverter from Q to V mode raises station-level StnRefScore at all the inverters in the multi-infeed system by roughly 8–10 percentage points (e.g., $V_{invBP12}$ from $\sim 66\%$ to $\sim 76\%$; V_{invBP3} from $\sim 63\%$ to $\sim 71\%$).
- Small Spread under Common Q Mode:** Under the same Q mode in the new BP1, different topologies/ratings (red, green, and blue bars) show minimal variation in station-level scores. For instance, $V_{rectBP3}$ StnRefScore remains in the narrow range of 56–57% for VSC2800(Q), Mixed2800(Q), and VSC2000(Q), suggesting that local converter technology alone does not markedly affect voltage stability.
- Diagnostic Tool:** StnRefScore helps pinpoint the *worst* and *best* voltage support sta-

tions in a quantitative manner. Here, Bipole 3’s rectifier trails at around 56%, whereas the new VSC Bipole 1 rectifier—taken as the highest performing station—serves as the **100% reference**. This stark contrast highlights the need for additional measures (e.g., synchronous condensers, STATCOMs) at lower-performing stations to ensure more robust post-fault voltage recovery across the multi-infeed network.

Bipole-Level Voltage CPI Insights: Figure 6.5 combines rectifier and inverter voltages into an overall bipole metric. The red, green, and blue bars (Q-mode) appear quite similar in magnitude for Bipoles 1–3, whereas the orange bars (V-mode) indicate a clear performance boost on station inverters and modest gains for the rectifiers.

The planned **Bipole 1** has the best voltage performance in VSC--VSC 2800 MW (V mode) scenario, compared to roughly 89–92% if the rating is reduced or a Mixed configuration is used (under Q mode). The existing LCC **Bipole 2’s StnRefScore** hovers around 76–84%, showing moderate improvement (+7–8%) whenever the new bipole (Bipole 1) switches to V mode. The existing LCC **Bipole 3’s StnRefScore** is typically the lowest in the set, around 68–69% under Q mode but improving to about 73% when Bipole 1 employs V mode. This emphasizes that even remote bipoles gain some voltage-stability benefits from improved AC voltage regulation on the new bipole.

Comparing Mixed2800(Q) in Green or VSC2000(Q) in Blue to the base VSC2800(Q) in Red indicates that *technology and rating changes alone* have limited impact on bipole voltages under the same control mode: VBP3, for instance, only shifts from 68% to 69%. Meanwhile, VBP1 sees its StnRefScore drop from 92% to 89% if the rating is lowered or if the converter is a Mixed Scheme.

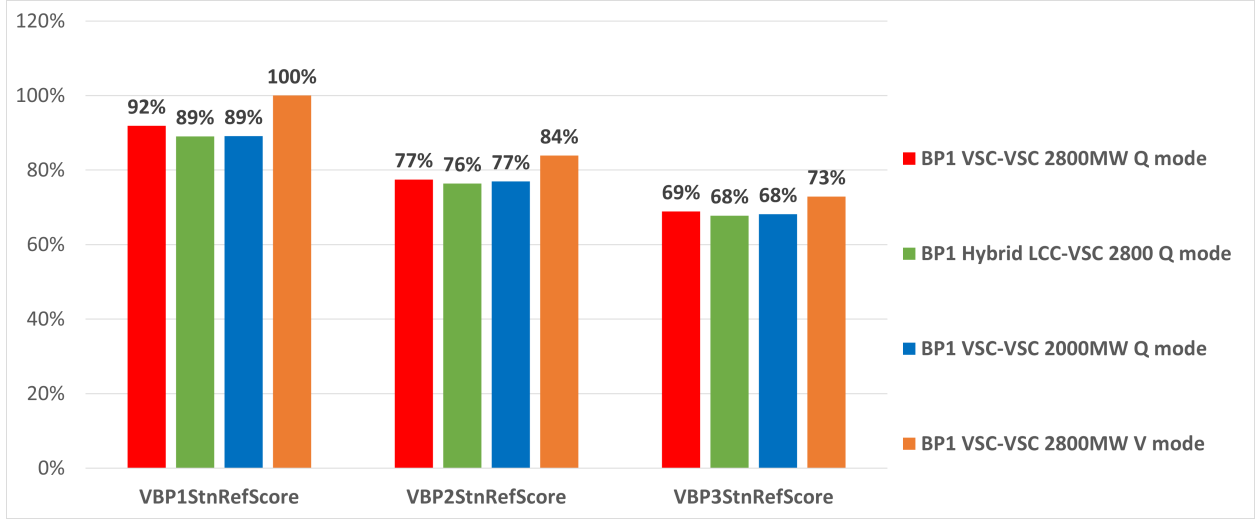


Figure 6.5: Bipole-Level Voltage StnRefScore across Bipole 1 Options

Collectively, these findings confirm that:

- **V mode** yields voltage recovery benefits *beyond* just the new bipole's own stations; the adjacent inverter can also gain this co-benefit.
- When Bipole is fixed in **Q mode**, differences in rating or topology of Bipole 1 design do not drastically change voltage StnCPI across the other existing Bipoles.

6.3.2 DC Power Station CPI in Multi-Infeed Scenarios

Having established station- and bipole-level voltage behaviour via $\mathbf{V}_m\text{StnCPI}$, we now turn to corridor-delivered power recovery: $\mathbf{P}_m\text{StnCPI}$ across BP1–BP3. Table 6.3 presents the StnCPI values for three possible implementations of a newly added Bipole 1, showing how each configuration (VSC–VSC at 2800 MW, Mixed LCC–VSC at 2800 MW, and VSC–VSC at 2000 MW) impacts the overall DC power excursion:

A larger $\mathbf{P}_m\text{StnCPI}$ indicates more pronounced power volatility when the five converter-

Table 6.3: DC Power StnCPI for Three Configurations of the New Bipole 1

BP1 Proposed Configuration	$P_{BP1}StnCPI$	$P_{BP2}StnCPI$	$P_{BP3}StnCPI$
VSC–VSC 2800 MW	1.041	2.332	1.970
Mixed LCC–VSC 2800 MW	2.065	2.398	1.970
VSC–VSC 2000 MW	1.263	2.350	1.977

bus faults are *collectively* considered; a smaller value signifies faster post-fault recovery. Since the BP1 VSC–VSC 2800 MW option attains the lowest $P_{BP1}StnCPI = 1.041$, it serves as the *reference* for computing the corresponding $P_mStnRefScore$. Figure 6.6 illustrates how each bipole’s $StnRefScore$ compares across the three configurations, capturing the recovery speed at which DC power returns to nominal after AC faults. When comparing effect of **HVDC topologies** (red/green/blue bars), the results show that the existing Bipoles 2 and 3 (labeled $P_{BP2}StnRefScore$ and $P_{BP3}StnRefScore$) remain relatively unaffected by which new Bipole 1 configuration is chosen (VSC–VSC 2800 MW, Mixed LCC–VSC 2800 MW, or VSC–VSC 2000 MW). In contrast, $P_{BP1}StnRefScore$ varies significantly: the best case is the 2800 MW VSC–VSC option (set at 100% reference), while using a mixed LCC–VSC reduces $P_{BP1}StnRefScore$ to around 50%, and reducing the rating to 2000 MW lowers it further to about 82% of the reference.

Such insights inform *coordination measures* intended to *speed up* the DC power recovery of bipoles with slower responses. Potential strategies include tuning PI controller gains, reducing the blocking period after AC faults, or even shifting from LCC-based to VSC-based technology to leverage faster converter dynamics. Determining the precise sequence of bipole recovery is often case-dependent, guided by both technical constraints (like converter design limits) and operational policies.

Overall, the $StnRefScore$ analysis indicates that Bipole 1’s rating and topology strongly

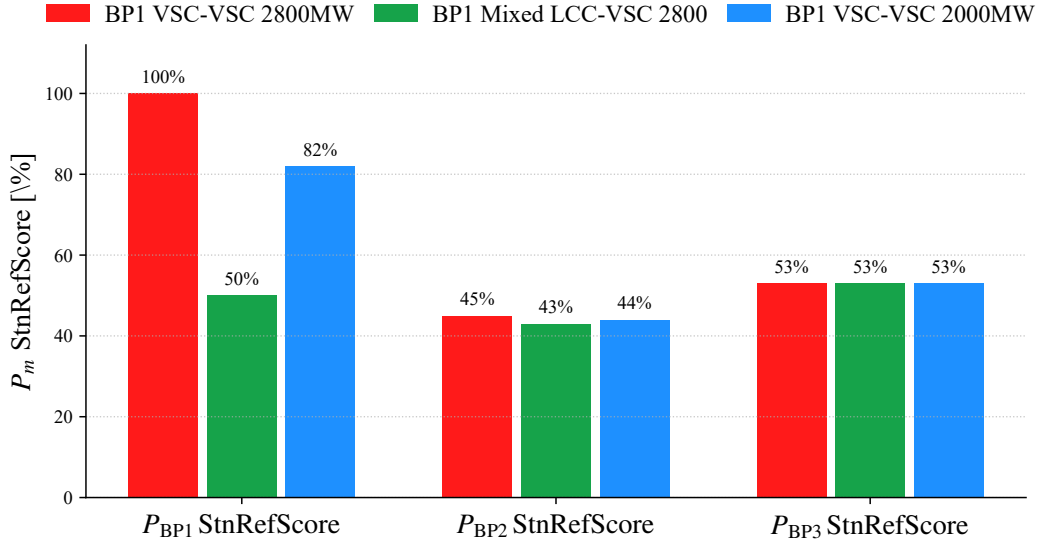


Figure 6.6: Individual Bipole Power StnRefScore Across Three Potential Configurations of the New Bipole 1.

influence its own power recovery, whereas Bipoles 2 and 3 remain less sensitive to these changes. Such a finding underscores the value of analyzing multi-infeed HVDC interactions when planning expansions or upgrades: stronger or higher-rated bipoles with VSC technology can help stabilize the system more rapidly, but smaller-scale bipoles with existing LCC technology may still require additional control adjustments to match the recovery performance of the newer installations.

6.3.3 Power–Frequency Correlation Across HVDC Topologies

The station power results set the stage for a joint view: we next map each contingency to $(\mathbf{PEvtCPI}^n, \mathbf{fEvtCPI}^n)$ to quantify power–frequency coupling and how it shifts with BP1 technology and rating.

Figure 6.7 extends the power–frequency relationship analysis (originally introduced in

Section 5.2.3) to include additional HVDC topologies and ratings. Each point represents a Event CPI for frequency (f_{EvtCPI}) and power (P_{EvtCPI}), computed according to Equation (4.4). Three different BP1 HVDC alternatives are illustrated as the red curve is VSC–VSC 2800 MW, the Green curve is Mixed LCC–VSC 2800 MW and the blue curve is VSC–VSC 2000 MW.

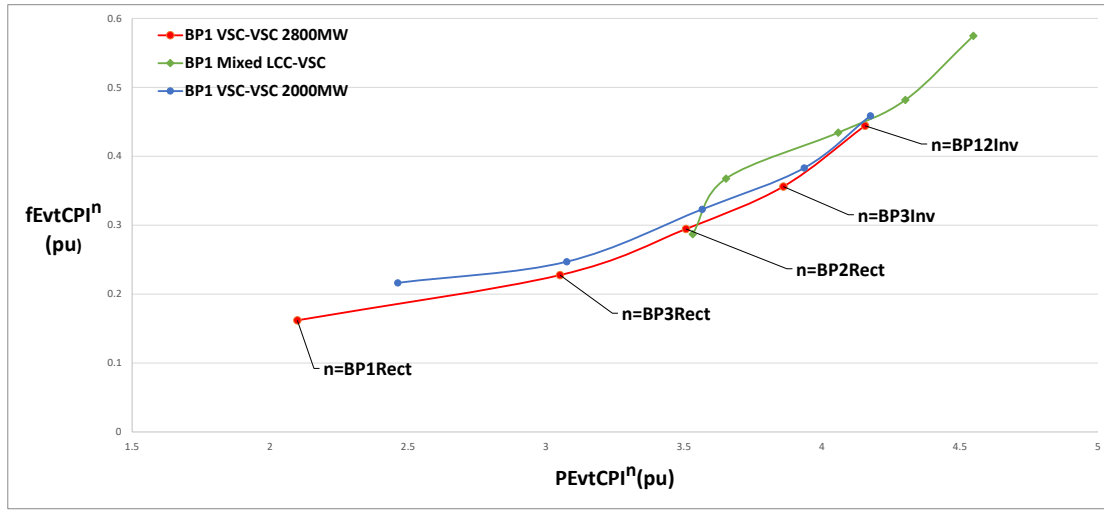


Figure 6.7: Power–Frequency Correlation with BP1 HVDC Configurations and Ratings

- **Persistent Positive Correlation:** Across all three configurations, higher P_{EvtCPI} coincides with higher f_{EvtCPI} : larger transient power swings translate into more severe frequency excursions.
- **Invariant Fault-location Ordering:** The relative frequency severity is consistent across all alternatives: $\text{BP1Rect} \rightarrow \text{BP3Rect} \rightarrow \text{BP2Rect} \rightarrow \text{BP3Inv} \rightarrow \text{BP12Inv}$. In particular, BP2Rect is the worst rectifier-side fault and BP12Inv the worst inverter-side fault in terms of combined power–frequency excursion.

- **Effect of HVDC Topology/Rating:** Although the *relative* fault severity does not change across topologies, the *absolute* positions of their five shifts with different topology or rating. The Mixed LCC–VSC 2800 MW points lie farthest from the origin (largest combined deviations), the VSC–VSC 2000 MW set is intermediate, and the VSC–VSC 2800 MW set is closest to the origin (best containment of power and frequency swings).

These results reinforce that while *where* a fault occurs drives the ranking of severities in terms of power and frequency, *how* BP1 is engineered (topology, rating) sets the overall amplitude of power–frequency stress—information directly actionable for planning and coordination studies.

6.4 Consolidation of CPI Methods and Key Findings

This section consolidates two complementary CPI-based ranking methods introduced earlier (Chapter 4, Section 4.4): the curve-based *UnifiedSysCPI*, which yields an absolute, event-transparent scalar from voltage and frequency system CPIs, and the score-based *SysRefScore*, which benchmarks each alternative as a percentage relative to a chosen reference. Together, they support both diagnostic traceability and portfolio-style comparisons.

6.4.1 Curve-Based Ranking of Planning Alternatives—*UnifiedSysCPI*

The curve-based UnifiedSysCPI method introduced for the single-infeed case (Chapter 4, Section 4.4.1) and extended to a three-bipole multi-infeed configuration (Chapter 5, Section 5.4). Now this section in Chapter 6 is generalized to compare *alternative* multi-infeed designs.

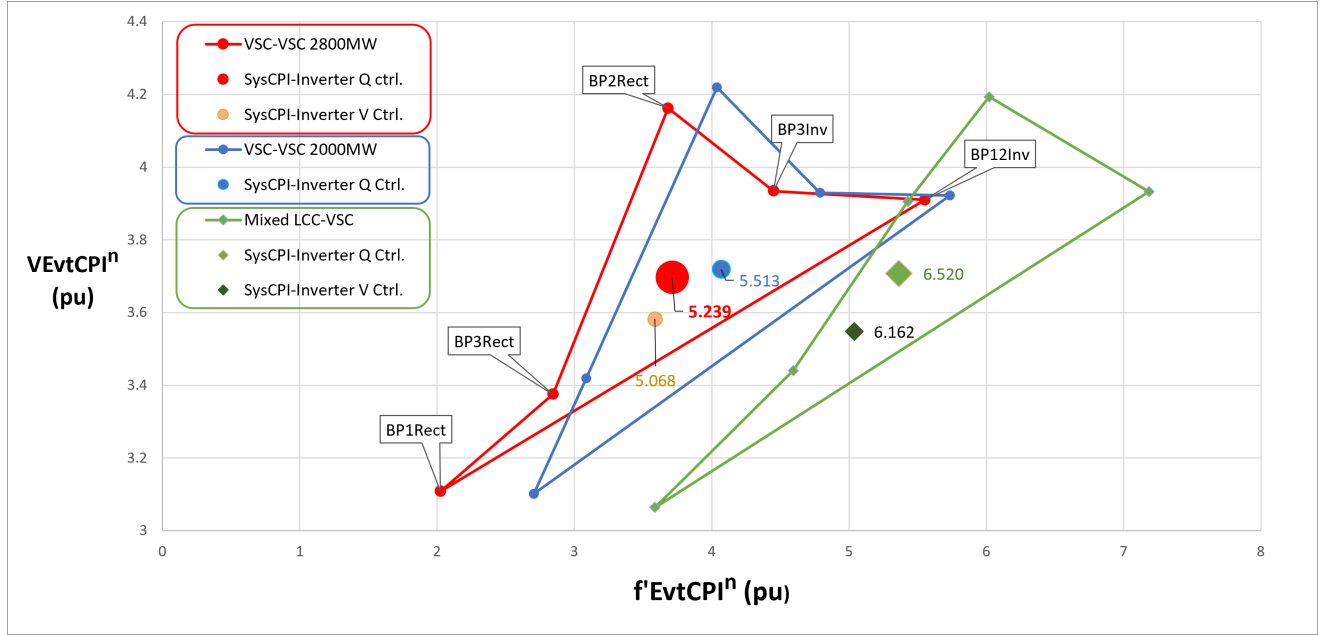
Figure 6.8 plots f_{EvtCPI} on the horizontal axis and V_{EvtCPI} on the vertical axis, capturing **event-level** responses for five distinct fault locations.

Each colored polygon (red, blue, green) connects the five event points for a given alternative (e.g., **VSC--VSC 2800 MW**, **VSC--VSC 2000 MW**, **Mixed LCC--VSC 2800 MW**) in a fixed vertex order to enable visual comparison.

Filled markers show the aggregated system coordinates (f'_{SysCPI} , V_{SysCPI}) for each alternative; the common Voltage-to-frequency scaling factor from Chapter 4 is used for all alternatives so that the axes are comparable across cases. The scalar *UnifiedSysCPI* are the Euclidean norm of those aggregate points; numeric values for (f'_{SysCPI} , V_{SysCPI}) and *UnifiedSysCPI* are also labelled in Figure 6.8 (e.g. *UnifiedSysCPI* of **VSC-VSC 2800 MW** in **V** mode yields the smallest value, 5.068, indicating the most robust plan across all the alternatives).

Relationship Between Frequency and Voltage CPI

Unlike the power–frequency plot (Section 6.3.3), here the axes are f_{EvtCPI}^n and V_{EvtCPI}^n . A large frequency excursion does *not* always coincide with a large voltage deviation. For example, **BP2Rect** sits near the top of the diagram (strong voltage stress) but not the farthest right (moderate frequency stress), reflecting the reality that reactive power (affecting voltage magnitude) and real power (affecting frequency) are partially decoupled in AC networks. Proximity to strong voltage-support devices (e.g., synchronous condensers, large generators, STATCOMs), as well as the chosen inverter control mode (reactive-power vs. voltage control), can further improve voltage dynamics of the converter station but frequency around the inverter depends on the controller’s response and nearby governor responses.



Axes: $x = f'_{EvtCPI}^n$, $y = V_{EvtCPI}^n$ (5 s window). *Polygons:* five event points per alternative *Filled markers:* $(f'_{SysCPI}, V_{SysCPI})$ per alternative; radial arrow length = *UnifiedSysCPI*. Closer to the origin indicates a more robust combined voltage–frequency response.

Figure 6.8: Event CPI Fault Characteristic Curves: f_{EvtCPI} vs. V_{EvtCPI}

Fault Severity Ordering Across Alternatives:

Despite these non-linearities, the *relative* ordering of faults is consistent across all three topologies/rating options (red, green, and blue polygons). That is, from the smallest frequency excursion to the largest (from left to right along the X axis), we always see $\text{BP1Rect} \rightarrow \text{BP3Rect} \rightarrow \text{BP2Rect} \rightarrow \text{BP3Inv} \rightarrow \text{BP12Inv}$, this is the same trend observed in Power/Frequency Event CPI Curve (Figure 6.7). On the other hand, from the smallest voltage fluctuation to the largest (from bottom to top along the y axis), we also always see $\text{BP1Rect} \rightarrow \text{BP3Rect} \rightarrow \text{BP12Inv} \rightarrow \text{BP3Inv} \rightarrow \text{BP2Rect}$.

New Bipole 1's Topology/Rating Impact on Contingency Severity:

Although fault severity order is invariant, system design choices—topology and rating—translate the entire point set (event polygons) toward or away from the origin: a closer origin indicates a more resilient response (smaller EvtCPI). **VSC–VSC 2800 MW red polygon** typically stays closest to the origin, implying smaller overall frequency/voltage deviations for the same five faults. **VSC–VSC 2000 MW (blue polygon)** shifts each fault's point slightly upward (higher voltage CPI) and to the right (higher frequency CPI) compared to the 2800 MW design, reflecting reduced system robustness and lastly **Mixed LCC–VSC 2800 MW (green polygon)** tends to occupy the highest region among the three, indicating the largest combined voltage/frequency excursions under the same fault scenarios.

New Bipole 1's Inverter Control Mode Impact on Contingency Severity:

Holding the rating and topology fixed, operating the new BP1 inverter in *voltage control* improves the aggregate outcome relative to *reactive-power control*, as seen by shorter

aggregate vectors (smaller UnifiedSysCPI) in Figure 6.8. This benefit appears both for a full VSC–VSC implementation and for a Mixed LCC–VSC design:

- **VSC–VSC 2800 MW:** aggregation moves from the **red dot** (reactive-power control; UnifiedSysCPI = 5.239) to the **orange dot** (voltage control; UnifiedSysCPI = 5.068).
- **Mixed LCC–VSC 2800 MW:** the **green diamond** (reactive-power control; UnifiedSysCPI = 6.520) shifts down to the **darker green diamond** (voltage control; UnifiedSysCPI = 6.162).

In summary, this curve-based method clarifies: (i) *which* contingencies dominate (event-level transparency) and (ii) *how* design choices (topology, rating, control mode) shift the entire alternative closer to or farther from the origin. The resulting UnifiedSysCPI provides a concise, absolute ranking while preserving drill-down to the contributing events.

6.4.2 Score-Based Ranking of Planning Alternatives—*SysRefScore*

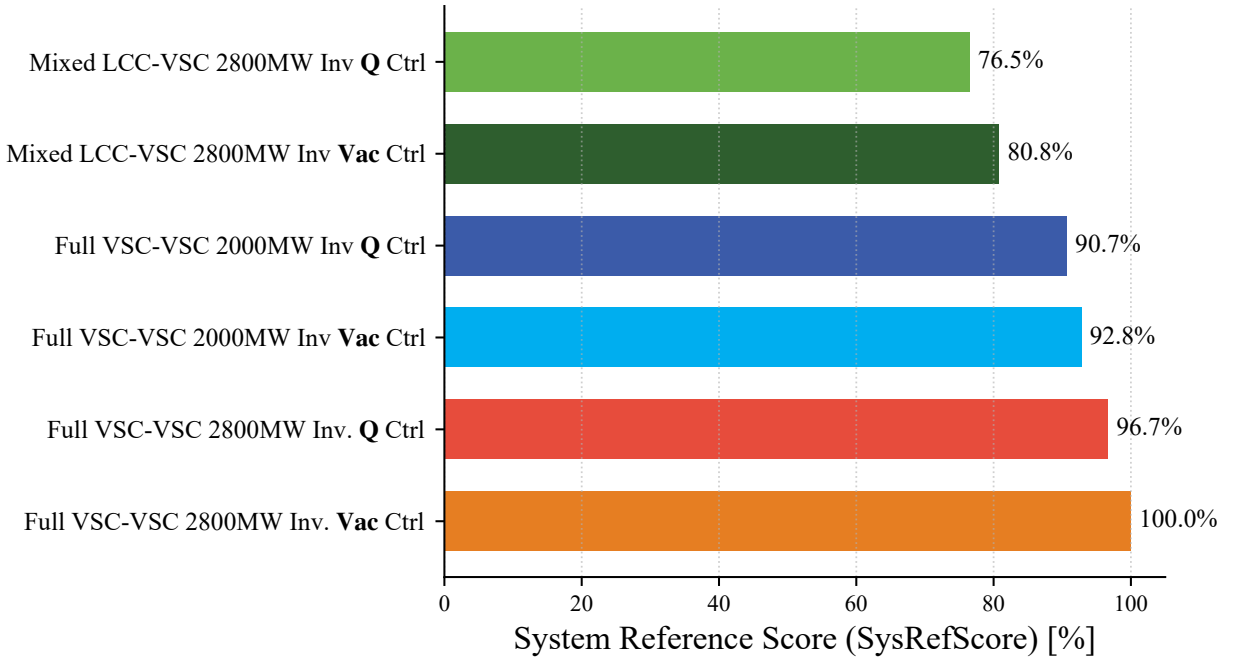
The score-based method benchmarks each alternative *relative* to a portfolio reference using the definition in Equation (4.10) (Chapter 4). Because *SysRefScore* is built from per-parameter ratios, no V/f scaling is required; equal importance of voltage and frequency is assumed unless stated otherwise. The result is a percent-style score (higher is better) that complements the absolute, curve-based *UnifiedSysCPI*.

Table 6.4 summarises six alternatives using both *UnifiedSysCPI* and *SysRefScore*, and Figure 6.9 provides a quick visual comparison.

Overall Ranking and Score Contrasts: From Table 6.4 the ranking (best → worst) is: Case 1 (VSC–VSC, 2800 MW, Voltage; 100%) > Case 4 (VSC–VSC, 2800 MW, Reactive;

Table 6.4: Comparison of Six Multi-Infeed HVDC Systems Using UnifiedSysCPI and SysRefScore

Case	New BP1 Scheme	Inverter Mode	Rating (MW)	UnifiedSysCPI	SysRefScore
1	VSC-VSC	Voltage	2800	5.068	100%
2	LCC-VSC	Voltage	2800	6.162	80.8%
3	VSC-VSC	Voltage	2000	5.450	92.8%
4	VSC-VSC	Reactive	2800	5.239	96.7%
5	LCC-VSC	Reactive	2800	6.520	76.5%
6	VSC-VSC	Reactive	2000	5.513	90.7%



Case 1 (VSC-VSC, 2800 MW, voltage control) attains the per-parameter minima in Eq. (4.10) and therefore scores 100%. Bars are ordered by score; higher is better.

Figure 6.9: Score-based ranking of planning alternatives (SysRefScore)

96.7%) > Case 3 (VSC-VSC, 2000 MW, Voltage; 92.8%) > Case 6 (VSC-VSC, 2000 MW, Reactive; 90.7%) > Case 2 (LCC-VSC, 2800 MW, Voltage; 80.8%) > Case 5 (LCC-VSC,

2800 MW, Reactive; 76.5%). Within a given topology/rating, *voltage control* outperforms *reactive-power control* (Case 1 > Case 4; Case 2 > Case 5); within a given topology/control mode, *higher rating* performs better (Case 1 > Case 3; Case 4 > Case 6). At equal rating/control, *VSC-VSC* exceeds *Mixed LCC-VSC* (Case 1/4 > Case 2/5).

Consistency with the Curve-based View: Scores decrease as *UnifiedSysCPI* increases, showing a monotonic alignment between the relative (reference-based) and absolute (distance-based) perspectives. Thus, the bar chart delivers a decision-ready ordering, while the event-CPI curve explains *why* alternatives differ (which fault locations and which parameter dominate).

In summary, *SysRefScore* is ideal when stakeholders want a concise, percent-style comparison against a clear benchmark. The choice of reference and parameter weights (Eq. (4.10)) can shift absolute scores; however, rank changes are typically limited to near-ties. Event-level detail is abstracted—consult the curve-based plots when diagnostic traceability is required.

6.5 Scenario Assessment of Multi-Infeed HVDC LVRT Capability

This section applies the RoC-CPI / LVRT-boundary method, developed in Section 5.5, to four representative multi-infeed HVDC architectures. The procedure for assessing LVRT capability across alternatives consists of: i) extracting the two-dimensional LVRT boundaries for each topology; ii) compressing those curves into a scalar *LVRT Capability Area* (LVRTCA) for rapid benchmarking; iii) discussing how converter type, inverter control mode, and rating shape the observable stability margin.

The findings provide planners with a concise, quantitative basis for selecting converter technologies and control strategies.

6.5.1 LVRT Boundaries Across HVDC Configurations

Building on the methodology introduced in Chapter 5, Section 5.5, this section applies the CPI-based framework to evaluate and compare LVRT boundaries of four different multi-infeed HVDC system configurations. Each configuration varies in either inverter control mode, system rating, or topology (VSC-only vs. Mixed LCC-VSC). The same simulation matrix of 288 fault scenarios is used to determine the Fault Ride Through (FRT) duration for various retained voltages (voltage level during the fault), and the LVRT Capability Area (LVRTCA) is computed as a scalar indicator of system-level fault resilience.

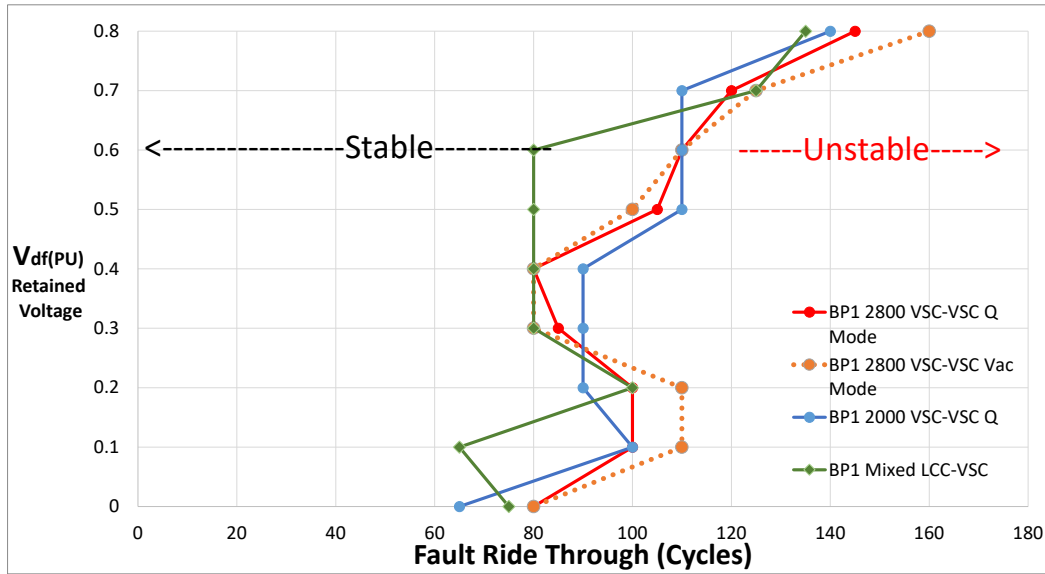


Figure 6.10: LVRT Boundaries of Bipole 1 Alternatives within Multi-Infeed System: Retained Voltage (pu) vs. Fault Ride-Through Duration (cycles)

Figure 6.10 illustrates the LVRT boundaries of the four scenarios, with fault ride-through

duration (in cycles) plotted against retained voltage levels ranging from 0 to 0.8 pu. Each curve traces the maximum stable fault duration for a given voltage depression, and the boundary separates stable from unstable operating regimes. These results are further summarized in Table 6.5, where the computed LVRTCA values quantify the overall ride-through margin.

Table 6.5: LVRT Comparison Table Across Four HVDC Alternatives of Bipole 1

	2800 VSC–VSC Q mode	2800 VSC–VSC Vac mode	2000 VSC–VSC Q mode	Mixed LCC–VSC Q mode
Post-Fault Voltage (pu)	Fault Ride Through (FRT) (cycles)			
0.0	80	80	65	75
0.1	100	110	100	65
0.2	100	110	90	100
0.3	85	85	90	80
0.4	80	80	90	80
0.5	105	105	110	80
0.6	110	110	110	80
0.7	120	125	110	125
0.8	145	160	140	135
LVRTCA ($pu \cdot cycles$)	81.25	84.5	80.25	71.5

Observations on LVRTCA across BP1 Alternatives

Across all alternatives, the LVRT curves exhibit a noticeable inflection in the moderate post-fault voltage range (0.3–0.6 pu). This nonlinearity is attributed to the activation of

under-voltage AC (UVAC) logic in the converter control systems. When the post-fault voltage falls below typical UVAC thresholds (e.g., 0.5–0.65 pu), converters switch control modes to preserve system integrity. Prolonged fault durations near this threshold can cause repeated transitions between control states, inducing sustained oscillations and eventual instability.

From the results, several conclusions can be drawn:

- *Ranking of LVRTCA (highest $\rightarrow$ lowest):* 2800 MW VSC–VSC (Voltage control) = **84.5** pu·cycles; 2800 MW VSC–VSC (Q mode) = **81.25**; 2000 MW VSC–VSC (Q mode) = **80.25**; Mixed LCC–VSC (Q mode) = **71.5**. The best–worst spread is ≈ 13 pu·cycles.
- *Consistency with CPI-based rankings:* This LVRTCA ordering directly *verifies* the rankings obtained in Section 6.4 using both methods—the curve-based *UnifiedSysCPI* and the score-based *SysRefScore*. In all cases, higher-rated VSC topologies with voltage control deliver the strongest recovery performance, whereas the mixed LCC–VSC alternative trails.

6.6 CPI-Based Screening vs. Established HVDC Index Families

Beyond the repeatable CPI workflow, comparative rankings (*UnifiedSysCPI*, *SysRefScore*), and LVRT boundaries across multiple alternatives outlined in the previous section, it is also useful to position the proposed CPI framework relative to established HVDC index families. Classical methods such as SCR/ESCR, VSF/MAP, MIIF, and EMT-based peak or

nadir indices each provide partial insights but struggle to provide a controller-sensitive, performance-scored-based method that enables fast, streamlined, and comparable screening of multi-infeed modernization options. As summarized in Table 6.6, the CPI-based approach extends these traditional indices by unifying voltage and frequency, integrating both magnitude and duration of disturbances, and offering transparent aggregation into event, station, and system-level scores. The main advantages can be summarized as follows:

- **One standardized EMT batch run:** Using PSCAD’s multi-run feature or Python Automation Program, a predefined set of faults is sequentially applied at each converter station. This produces the full $m \times n$ event–station CPI matrix from one case setup; subsequent aggregation yields contingencies’ ranking (*EvtCPI*), station’s ranking (*StnCPI/StnRefScore*), and a unified system score (*SysCPI*).
- **Controller-sensitive:** Because CPIs are derived from full-order EMT waveforms, they capture PLL behaviour, current limiting, DC-link dynamics, and inner control loops—effects that static SCR/ESCR, VSF, or MAP approximations cannot reflect.
- **Time-integrated performance:** Instead of reporting only a single peak (TOV) or nadir (frequency), the CPI integrates deviations over a 4–5 s recovery window, penalizing both sharp excursions and prolonged shallow dips; and hence both extreme values and time duration are considered.
- **Voltage–frequency unification:** Separate insights can be drawn from V_{SysCPI} and f_{SysCPI} , while a combined UnifiedSysCPI distance offers a single performance yardstick.
- **Converter-technology agnostic:** The same procedure applies to LCC, VSC, and mixed LCC–VSC alternatives, enabling like-for-like comparisons across modernization options.

- **Direct ranking and communication:** *StnRefScore* normalizes station performance to 0–100%, while $\mathbf{X}_{\text{SysCPI}}$ and *UnifiedSysCPI* provide headline system metrics to support clear planning decisions.

Overall, CPI-based screening provides the *controller-sensitive as well as computationally light* method for judging frequency and voltage resilience of competing multi-infeed HVDC upgrade strategies—addressing the key gaps of traditional index families in modern multi-infeed HVDC planning.

Table 6.6: How the **CPI** framework compares with the four main families of HVDC indices

Capability Feature	System -strength (SCR/ ESCR/AISCR)	Quasi-Static margins (VSF /MAP/CSI)	Interaction factors (MIIF/ RF/UIF/MVIF)	Simulation- Based indices (CCT/CFII/- TOV/Nadir)	This Thesis Work (CPI framework)
Closed-loop, controller-aware	✗	✗	✗	✓ one fault at a time	✓
Applicable to VSC	$\pm(\text{AISCR}, \text{HMIESCR})$	✗	$\pm(\text{MVIF})$	$\pm(\text{CCT})$	✓
Multi-infeed handled natively	✓(ex.MIESCR)	✓(one bus at a time)	$\pm(\text{pair-wiseonly})$	$\pm(\text{cocurrent/LocalCFII for LCC only})$	✓
Ranks <i>stations</i>	✓	✗	✗	✗	✓ StnRefScore
Ranks <i>contingencies</i>	✗	✗	✗	✗ single-event focus	✓ EvtCPI
System-level scalar available	✓	✗	✗	✗	✓ $\text{SysCPI}(f, V)$
Voltage & frequency unified	✗	✗	✗ Separate V/f indices	✗	✓ UnifiedSysCPI
Duration <i>and</i> magnitude	✗	✗	✗	✗ peaks/nadirs only	✓ CPI integrates over 5 s window
Extensible weighting (station, fault)	✗	✗	✗	✗	✓ uniform or user-defined weights

Legend: ✓ = capability broadly available; ✗ = absent; $\pm$ = partial/special-case.

Chapter 6 Summary

Chapter 6 operationalises the CPI concepts from earlier chapters into a *planning-grade* toolkit and applies them to rank HVDC alternatives. The main contributions are:

- 1. End-to-End Workflow** A seven-stage procedure (Fig. 6.1) now links fault simulation, on-line/off-line CPI computation, weighting, aggregation, visualisation, and composite scoring. The workflow is model-agnostic and can be quickly re-run for any new HVDC alternative.
- 2. Dual Toolchain Validation** A PSCAD online module and a Python/GUI offline post-processor produce consistent CPI values, removing manual spreadsheet steps and improving repeatability.
- 3. Granular Insights into Multi-Infeed Dynamics**
 - DC-power StnRefScore pinpointed Bipole 1 as the fastest recovering link, while Bipole 2 persistently lagged under every topology tested.
 - Station- and bipole-level voltage StnRefScore revealed that switching the inverter from reactive power to AC-voltage control mode raises the *local* inverter's score by about 10 percentage points, and still delivers roughly 8 percentage points of improvement at the *adjacent* inverter.
 - Power–frequency and voltage–frequency characteristic curves confirmed that fault *location* dominates severity ranking, whereas topology and rating simply scale the absolute excursion.

- 4. Unified Ranking via Composite Indices** Two alternatives ranking schemes—Curve-Based *Unified-SysCPI* and Score-Based *SysRefScore* were applied to six representative designs of Bipole 1. All three agreed on the same ordering: (a) VSC–VSC 2800 MW, *V*-mode (best); (b) VSC–VSC 2800 MW, *Q*-mode; (c) VSC–VSC 2000 MW, *V*-mode; (d) VSC–VSC 2000 MW, *Q*-mode; (e) Mixed LCC–VSC 2800 MW, *V*-mode; (f) Mixed LCC–VSC 2800 MW, *Q*-mode (worst).
- 5. Ride-Through Benchmarking** Extending the RoC-CPI method, two-dimensional LVRT boundaries were extracted and compressed into the scalar *LVRT Capability Area* (LVRTCA). The LVRTCA ranking *directly verifies* the CPI-based results (*UnifiedSysCPI* and *SysRefScore*): inverter AC-voltage control and higher rating produce larger LVRTCA (strong resilience), whereas the Mixed LCC–VSC topology remains the weakest performer.
- 6. Cross-Walk to Established Index Families** The CPI framework was mapped onto four established HVDC index families, showing that CPI preserves controller awareness, naturally handles multi-infeed interactions, provides station-/event-/system-level rankings, unifies voltage–frequency metrics, and scales efficiently for batch EMT studies. This alignment clarifies when the existing indices remain useful and when CPI should be preferred for controller-accurate, system-wide trade-off decisions.

Chapter 7

Conclusions, Contributions and Future Work

This chapter concludes the thesis by summarizing the main contributions and insights gained from the development of the Control Performance Index (CPI) framework for multi-infeed HVDC systems. The framework provides a standardized basis to compare alternative HVDC configurations—both in-service and proposed—under a common set of contingencies, windows, and weights, translating EMT simulation results into concise, decision-ready metrics. It also outlines the practical implications for system planners and suggests directions for future research and industry application.

7.1 Summary of Findings and Contributions

This thesis introduced a unified, controller-aware evaluation framework that translates electromagnetic transient (EMT) simulation results into concise, decision-ready metrics. Key findings and contributions include:

1. **Unified Performance Index:** A general CPI formulation converts voltage, frequency, and DC power waveforms into scalar scores via squared-error integration over a fixed time window. CPI jointly penalizes *magnitude* and *duration*, offering a more representative resilience measure than traditional peak-based metrics.
2. **Triple Layer Aggregation CPI Framework:** A structured method to condense raw EMT waveforms into (i) Event-CPI (aggregation over stations), (ii) Station-CPI (aggregation over contingencies), and (iii) System-CPI (double aggregation). One EMT sweep yields a ranked fault list, a ranked station list, and a headline system score.
3. **Correlation Across Domains:** A strong and consistent relationship was observed between DC power deficits and frequency excursions. This insight allows early identification of critical stations without exhaustive EMT exploration.
4. **Graphical Diagnostic Tools:** The Event-CPI curve (f_{EvtCPI}^n vs. VE_{vtCPI}^n) and related plots support planners with intuitive visuals that reveal non-linear voltage-frequency interactions, show fault-severity ordering, and illustrate how topology, rating, and control mode shift overall resilience.
5. **Ranking and Benchmarking of Design Alternatives:** Quantitative evaluation across multiple design scenarios revealed that VSC-VSC configurations outperform Mixed LCC-VSC by roughly 20–24%; higher ratings (2800 MW vs. 2000 MW) improve scores by about 6–7%; and inverter *AC-voltage control* typically adds a further 3–4% over *reactive-power control*.
6. **LVRT Capability Metric:** Extending the RoC-CPI method, two-dimensional fault sweeps (duration and sag depth) produced LVRT stability boundaries; integrating

these yields a compact *LVRT Capability Area* for consistent and topology-agnostic comparison.

7. **Automated Critical-Clearing Time Detection:** The peak rate-of-change of the system CPI reliably identified the critical-clearing point for solid and high-impedance faults, removing subjective tuning from traditional waveform-based CCT searches.
8. **Toolchain Integration:** A modular PSCAD to Python workflow was implemented to automate CPI computation, weighting, and visualization, enabling scalable EMT campaigns and streamlined screening processes.

These contributions form a controller-sensitive, technology-agnostic, and computationally light framework for resilience assessment in evolving HVDC grids.

7.2 Practical Implications

- The CPI-based method allows planners to proactively pinpoint the most vulnerable converter stations and critical AC fault locations.
- LVRT capability area offers a compact benchmark for comparing system-level resilience across various topologies, control modes, and rating combinations.
- The PSCAD–Python GUI toolkit supports rapid screening of upgrade options and can be directly adopted by utilities for internal assessments.
- This framework generalizes traditional metrics into dynamic, duration-aware indicators, bridging the gap between static indices and full EMT waveforms.

7.3 CPI Conclusions for Manitoba Hydro’s Three-Bipole System

Building on the planning implications above, this section distills the Manitoba Hydro system-specific findings from the CPI analyses into concise, decision-oriented conclusions. The focus is on *what the results imply* for the three-bipole multi-infeed system—namely DC-power recovery, voltage performance, power–frequency coupling, contingency severity, alternative ranking, LVRT alignment and planning alternative insights.

DC Power Recovery (*StnRefScore*)

The *Station Reference Score* for DC power cleanly separates the three bipoles and reveals their sensitivity to topology, rating, and control choices.

- *Ranking and sensitivity to design:* The new VSC–VSC Bipole 1 spans roughly 50%–100% across its alternatives, reflecting sensitivity to topology and rating; Bipole 2 remains tightly clustered around 43%–45%, a narrow band plausibly due to electrical proximity/coupling to BP1; Bipole 3 sits near 53% and is largely insensitive to BP1’s design choices.
- *Converter dynamics under VSC vs LCC:* Under identical contingencies, *VSC* recovers DC power faster than *LCC*, explaining the persistent underperformance of the two LCC bipoles (BP2 the weakest).
- *Coordination measures for future studies:* The developed CPI metrics can be a guidance for Manitoba Hydro HVDC multi-infeed coordination studies: tune PI gains, shorten

post-fault blocking periods of LCC, or shift from LCC- to VSC-based solutions to accelerate slower links. The precise recovery sequence of the Three Bipoles System is case-dependent, shaped by converter limits and operating policy.

Voltage Performance (*StnRefScore* at Station/Bipole Levels)

The voltage *StnRefScore* highlights the dominant role of inverter control mode and distinguishes station-level (inverter side) from bipole-level benefits.

- *Converter-station (inverter-side) effect:* Switching the new Bipole 1 inverter from reactive-power (Q) control to AC-voltage (V) control materially improves post-fault voltage recovery at both local (BP1&2Inv) and adjacent (BP3Inv) inverter stations within the study multi-infeed system. Both inverter stations move up by about +8–10 percentage points (e.g. BP1/2Inv from 66% to 76%, BP3Inv from 63% to 71%). This aligns with the expectation that explicit V_{ac} regulation at the upgraded VSC inverter improves local voltage transient response, and the adjacent inverter can gain this co-benefit.
- *Bipole-level uplift:* With Bipole 1 in V -mode, bipole-level voltage scores rise across the system: BP1 $\approx +8\%$, BP2 $\approx +7\%$, BP3 $\approx +4\%$.
- *Control mode as the primary lever:* the choice between V - and Q -mode dominates voltage outcomes; topology/rating changes are secondary. When all inverters remain in Q -mode, altering the new Bipole 1’s rating or topology does not materially shift voltage *StnRefScore* at Bipoles 2 and 3.
- *Diagnostic insight (slowest vs. strongest):* *StnRefScore* pinpoints the weakest voltage-recovery station (Bipole 3 rectifier, $\sim 56\%$) and the best-performing reference (new

VSC Bipole 1 rectifier at 100%). Lower-performing stations may warrant additional voltage support (e.g., synchronous condensers, STATCOMs).

Event-Level Correlation and Contingency Severity (Power–Frequency–Voltage)

- *Power–frequency co-benefit*: Measures that speed up power recovery typically reduce frequency excursions as well—e.g., tuning PI gains, adopting faster controller strategies, shortening post-fault blocking, migrating from LCC to VSC to leverage faster converter dynamics, and coordinating the sequence of bipole recovery.
- *Fault-location effect (frequency)*: **Inverter-bus faults** (BP1&2 shared inverter bus; BP3 inverter bus) consistently produce the largest fEvtCPI; **rectifier-bus faults** are least severe. This frequency ordering is robust across alternatives.
- *Metric-specific severity (frequency vs. voltage)*: Voltage CPIs can rank contingencies differently from frequency CPIs. A fault that is most severe in frequency terms may not be the most severe in voltage terms; the two metrics provide complementary stress lenses.
- *Future study direction*: After identifying the worst frequency and worst voltage contingencies, prioritise those events for detailed protection settings, controller tuning, and coordination studies.

Alternative Ranking (Design Levers for Bipole 1 Modernization)

Both the curve-based *UnifiedSysCPI* and the score-based *SysRefScore* yield the same ordering of Bipole 1 modernization alternatives; the levers below explain that ordering.

- *Methods agreement:* Curve-based *UnifiedSysCPI* and score-based *SysRefScore* produce the same ordering.
- *Bipole 1 VSC Design Rating effect:* 2800 MW > 2000 MW for both power and voltage CPIs.
- *Bipole 1 VSC Inverter Control mode:* Inverter *V*-mode > *Q*-mode across metrics (lower CPIs, higher scores).
- *Bipole 1 VSC Design Topology:* Fully-VSC > mixed LCC-VSC; in DC-power *StnRefScore* terms, the mixed option can lag the best VSC design by $\sim 20\%$.
- *Overall conclusion of Bipole 1 Design:* Designs combining fully VSC, higher rating (2800 MW), and inverter *V*-mode are consistently favoured by both ranking methods.

Ride-Through Consistency (*LVRTCA*)

- *Alignment with CPI rankings:* The LVRT capability area (*LVRTCA*) agrees with CPI-based rankings: designs that score higher under *UnifiedSysCPI/SysRefScore* also exhibit larger Manitoba Hydro Three Bipole System LVRT areas. This cross-validation supports using the CPI framework as a planning-grade screening tool for Manitoba Hydro: the same design choices that improve CPI-measured power/voltage/frequency performance also improve ride-through.

7.4 Limitations of the Proposed CPI Framework

The CPI framework offers a structured, technology-agnostic screening tool, but several limitations remain, arising from EMT computational cost, model fidelity, the chosen recovery

window, and the scope of dynamics captured.

Computational Burden of EMT Simulations

Each contingency still requires an EMT run. For large multi-infeed networks, this becomes time-consuming and can constrain early-stage screening when many alternatives must be compared.

Dependence on Model Fidelity

CPI outcomes depend on converter and network model detail (e.g., PLL tuning, current limiters, protections, governor models). Where vendor-grade models are unavailable and generic templates are used, absolute CPI magnitudes carry uncertainty; relative comparisons are generally more reliable.

Sensitivity to Post-Fault Analysis Window

CPI values depend on the recovery window (5 s in this thesis): longer windows penalise slow recovery, whereas shorter windows may miss secondary oscillations. Consequently, rankings may shift with the selected time horizon. This limitation can be mitigated by performing a short robustness check (e.g. various time windows) and reporting where rankings are invariant.

Scope of Captured Dynamics

This study targets post-fault voltage, frequency, and power recovery. It does not quantify harmonics, subsynchronous interactions, commutation-failure statistics, very fast transients, or detailed relay behaviour. The method is intended for system-level screening rather than

exhaustive dynamic compliance assessment. It is recommended that CPIs be used for system-level screening, then specialised studies (SSR, harmonics, EMT relay validation) are applied to shortlisted options.

Within these limits, the CPI methodology is best positioned as a planning-grade *screening* tool that narrows design options, and then the planner can easily focus detailed compliance studies on the most promising alternatives selected by the CPI approach.

7.5 Future Research Directions

Building on the contributions of this thesis and limitations of the proposed approach, several promising directions can extend and generalize the CPI methodology for both academic study and industrial application. These opportunities are summarised below.

Shorter and Split Post-Fault Windows

The present work evaluates disturbances over a 4–5 second post-fault window. Future studies could distinguish between the *fault-on* interval and the *recovery* interval, thereby producing two complementary CPI measures. Such a refinement would separately capture the severity of the immediate fault response and the speed of subsequent recovery, offering a more nuanced characterisation of converter and system performance.

Expanded Fault Contingencies

The CPI framework has thus far been applied primarily to balanced AC three-phase faults at converter terminals. Extending the contingency set to include unbalanced AC events (e.g., single line-to-ground or phase-to-phase faults), DC line faults, and dc fault

restart sequences that involve both LCC and VSC technologies would significantly broaden the applicability of the method. Such scenarios are particularly relevant in future mixed-technology corridors and offshore HVDC grids.

Incorporation of Grid-Forming Controls

Emerging grid-forming converter strategies provide inertia, damping, and voltage support that are not captured by conventional grid-following controls. Integrating grid-forming behaviour into the CPI formulation would enable more holistic stability assessment across a wider spectrum of fault scenarios, particularly as system operators adopt grid-forming inverters in both HVDC and renewable plants.

Variable Weighting Schemes

All CPI aggregation in this thesis employed uniform weighting across fault locations and stations. In practice, contingency likelihood, station criticality, or operator priorities may justify non-uniform weightings. Future work should investigate adaptive weighting strategies to better align the CPI framework with practical planning and operational decision-making.

Real-Time Monitoring Integration

At present, the CPI framework has been applied in an offline EMT simulation environment. A practical research direction is to derive *critical CPI thresholds* from offline EMT studies for representative contingencies and then use them as *predictors* in real-time monitoring infrastructures such as phasor measurement units (PMUs) and wide-area monitoring systems (WAMS): when the online CPI approaches or exceeds its offline threshold, automated remedial actions can be triggered. Candidate actions include fast power injection/absorption

(e.g., BESS or HVDC modulation), temporary HVDC re-dispatch, controlled load tripping or curtailment, and switching of shunt devices to stabilise voltage. Such integration could bridge the gap between offline planning studies and online remedial action schemes, enabling CPI-based early warning or corrective-control triggers.

In summary, this thesis provides a robust foundation for next-generation HVDC screening and resilience benchmarking, with substantial potential for industrial uptake and continued academic development.

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