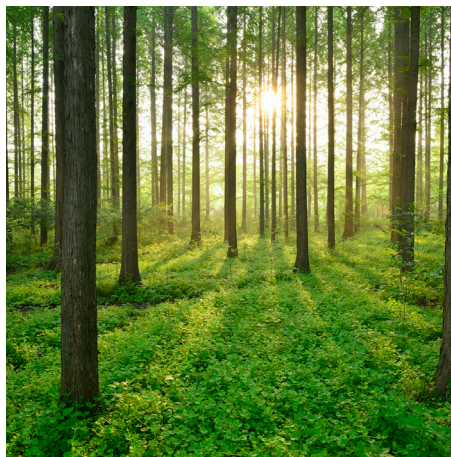


HYBRID AC MTDC TRANSMISSION SYSTEMHYBRID AC MTDC TRANSMISSION SYSTEM

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ELNÄTENS HÅLLBARA TEKNIK-
UTVECKLING OCH DIGITALISERING



Hybrid AC MTCD Transmission System

Report on specifications, costs, and simulations

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Förord

Projektet *Hybrid AC/DC dubbelledning* ingår i programmet *Elnätens hållbara teknikutveckling och digitalisering* med syftet att undersöka möjligheten att utveckla en befintlig dubbelkrets AC-ledning till ett hybrid AC/DC-system med multiterminal HVDC (MTDC). Projektet visar att hybrid AC/DC MTDC kan vara en tekniskt attraktiv metod för att förstärka befintliga elöverföringskorridorer, men att den högre kostnaden och den ökade tekniska komplexiteten gör att lösningen främst bör användas i situationer där traditionell AC-förstärkning inte är tillräcklig.

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Summary

This project explored the concept of converting a hybrid AC DC transmission line to a multiterminal DC system working in parallel with the AC grid. The scope of work included the development of the concept, preliminary specifications, high-level cost estimation, and simulation studies.

Power transmission systems including that in Sweden are under stress due to a variety of factors that include rapid electrification, rise of distributed renewables, and lagging investments in grid expansion. This necessitates long- and short-term planning in expansion and the so-called grid enhancement technologies, respectively. One such grid enhancement technology is embedded HVDC transmission which offers enhanced stability, improved loading, and flow control, among others. Technical and economic challenges with embedded HVDC option should, however, be considered before making an investment decision.

Adoption of embedded HVDC can start with hybridizing a double-circuit AC line by converting one circuit to DC. Once such a system is in place, load, and generation growth along such a hybrid line can usually be connected to the AC line by tapping it and creating nodes. The capability of the additional nodes to exchange energy with the rest of the power system through this is restricted by the conductor current and other technical concerns. This project explores the possibility of creating a node which connects the AC and DC circuits through an AC DC converter, which naturally provides more paths for energy exchange between new nodes and the rest of the power system.

The report covers the introduction to the basic concept of hybridization of a double-circuit AC line by converting one circuit to DC, the connection of new nodes to the AC circuit of such a hybrid line, and the connection of an additional AC DC converter to facilitate better connectivity. The chapters include introduction to this evolution, specifications as the system evolves, high-level cost estimate, and simulations studies investigating various technical aspects of such systems.

It is emphasized that this is a preliminary exploration of such solutions and several technical and economic investigations should be carried out before making investment decisions on such concepts. The objectives of technically sound and economically viable integration of new generation and demand into a power system can be achieved in many ways. The best solution is the one that provides the greatest value for money keeping in view several factors which are beyond the purview of this work.

Keywords

Power transmission, hybrid transmission line, HVDC, multiterminal HVDC, renewable energy integration

(Swedish translation of keywords: Kraftöverföring, hybridöverföringskorridor, HVDC, multiterminal HVDC, integration av förnybar energi)

Sammanfattning

Projektet handlar om en preliminär utforskning av konceptet att konvertera en hybrid AC DC-transmissionslinje till ett multiterminalt DC-system som arbetar parallellt med AC-nätet. Arbetsområdet inkluderade utveckling av konceptet, preliminär specifikationer, högnivåkostnadsuppskattning och simuleringsstudier.

Elöverföringssystem, inklusive de i Sverige, är under press på grund av en rad faktorer, inklusive snabb elektrifiering, ökning av distribuerade förnybara källor och eftersläpande investeringar i nätutbyggnad. Detta kräver långsiktig och kortsiktig planering av expansion respektive de så kallade nätförbättringsteknologierna. En sådan nätförbättringsteknologi är inbäddad HVDC-transmission som erbjuder ökad stabilitet, förbättrad belastning och flödeskontroll bland annat. Tekniska och ekonomiska utmaningar med inbäddad HVDC bör dock beaktas innan ett investeringsbeslut fattas.

Införandet av inbäddad HVDC kan börja med att hybridisera en dubbelkrets växelströmsledning genom att konvertera en krets till likström. När ett sådant system väl är på plats kan belastning och produktionstillväxt längs en sådan hybridlinje vanligtvis kopplas till växelströmsledningen genom att skapa noder för effektuttag/effektinmatning längsmed ledningen. Möjligheten hos de extra noderna att utbyta energi med resten av kraftsystemet genom detta begränsas av ledarströmmen och andra tekniska aspekter. Detta projekt undersöker möjligheten att koppla ihop AC- och DC-kretsarna genom att skapa en nod via en AC-DC-omvandlare, vilket naturligtvis ger fler vägar för energiutbyte mellan nya noder och resten av kraftsystemet.

Rapporten omfattar introduktionen till det grundläggande konceptet hybridisering av en dubbelkrets AC-linje genom att konvertera en krets till DC, anslutning av nya noder till AC-kretsen för en sådan hybridlinje samt anslutning av en extra AC-DC-omvandlare för att underlätta bättre anslutning. Rapportens kapitel inkluderar en introduktion till denna utveckling, specifikationer i takt med att systemet utvecklas, högnivåkostnadsuppskattningar och simuleringsstudier som undersöker olika tekniska aspekter av sådana system.

Det betonas att detta är en preliminär undersökning av sådana lösningar och att flera tekniska och ekonomiska undersökningar bör genomföras innan investeringsbeslut fattas om sådana koncept. Målen om tekniskt hållbar och ekonomiskt hållbar integration av ny produktion och efterfrågan i ett kraftsystem kan uppnås på många sätt. Den bästa lösningen är den som ger störst värde för pengarna med hänsyn till flera faktorer som ligger utanför detta arbetes räckvidd.

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1 Introduction

The consumption of energy in the form of electricity is increasing due to several trends, some of which are:

- electrification of sectors which, in the past, were powered by fossil fuels,
- the unprecedented growth of renewable energy sources,
- rapid deployment of energy storage,
- increasing population and increasing per capita energy consumption,
- economic development, and
- rapid growth in the energy consumption of digital services such as cloud services and artificial intelligence.

The power grid, basically a meshed infrastructure of conductors, is the mechanism of energy exchange between the energy sources and loads. It is quite clear that more conducting volume will be required for exchanging more power between the increasing numbers of sources and loads.

The power transmission system in any country or region spans the entire country consisting of substations, transmission lines, cables, control systems, and other equipment. The system is most often connected to bordering countries through interconnectors for economic energy trade.

Overhead transmission lines operate at high voltage to reduce line currents enabling economic construction and operation. The lines are, therefore, suspended high above ground supported by tall towers or poles to provide necessary clearance from the ground for the extremely high voltages involved. These lines also must pass through difficult terrain. Construction of such transmission lines is, therefore, an engineering challenge. Naturally, load and generation growth can only be accommodated by constructing more transmission lines. However, the costs involved and the general public opposition to the construction of new lines, particularly in Europe, has led to a situation where the transmission grid in Sweden is stressed, i.e., there are not as many transmission lines as there should be. This situation is expected to continue and possibly worsen as regulatory regimes have lagged behind the recent trends in the electrification space.

1.1 HIGH-VOLTAGE AC TRANSMISSION

Transmission systems are dominated by high-voltage alternating current (HVAC) technology where the polarity of line voltage and current *alternates* between positive and negative 100 and 120 times a second for 50 Hz and 60 Hz systems, respectively. The transmission network consists of several voltage levels which should be connected to each other through power transformers. The main reason AC technology dominates power transmission is because transformation of voltage levels is cheap and efficient with AC transformers.

Sometimes, a transmission line between two locations is the so-called double circuit line, i.e. two three-phase “circuits” share the transmission corridor and support structures. This helps reduce the cost of transmission at the same time increasing the availability in case of failure of one of the circuits.

1.2 GRID CONGESTION AND THE NEED FOR GRID ENHANCEMENT TECHNOLOGIES

There are several technical reasons due to which transmission lines cannot be loaded up to their thermal capacities in many cases (i.e. the maximum possible capacity considering the conductor cross-sectional area). This means that the existing network can carry more power, in principle, and can connect more sources and loads. This is an active area of research for transmission system operators (TSOs), distribution system operators (DSOs), power engineering industry, and academia. Measures and solutions that help enhance the capacity of grid systems are referred to as grid enhancement technologies (GETs), even though some measures do not qualify as technologies. GETs can be broadly classified into the following categories, noting that this classification is not unique and that solutions may fall under more than one category depending upon how they are viewed.

1. **Power technology:** These are general systems which are subjected to high voltage or high currents on the power system. Systems such as flexible AC transmission systems (FACTS) technology, high voltage direct current (HVDC), synchronous condensers, and fixed capacitors & inductors are some of the power equipment which can be added to the system to enhance the power carrying capacity of a network.
2. **Information, communication, and software technologies:** These are technologies where sensors, communication networks, and software enhance the observability of the states of the system. Enabled by these technologies, automated control actions in real time unlock previously unavailable capacity. Dynamic asset rating, advanced artificial intelligence (AI)-assisted control center operation, advanced system protection, and smarter breaker settings are some of the solutions that fall under this category.
3. **Operational measures:** Measures which can be implemented with improvement in current operating procedures are part of this category. Reconfiguration of grid paths, improved asset management, dynamic protection systems, and the use of probabilistic methods are a few examples in the toolset available in this category.
4. **Market measures:** These are measures where user behavior for enhanced loadability of the system is encouraged through financial incentives. The solutions include flexibility markets, ancillary services market, energy storage, demand side response, and microgrids.
5. **Regulatory measures:** The category consists of measures taken at a regulatory level. These include improvements in regulations to enable

higher loadability of the existing assets without jeopardizing stability and the relaxation of N-1 reliability criteria.

The details of GETs are not the focus of this work, however, HVDC is one of the technologies with large potential to alleviate the current grid congestion issues, in addition to other benefits that this technology brings to the table for stable and reliable operation of the transmission system. That is why we introduce it in a dedicated section below.

1.3 HVDC

HVDC technology utilizes direct voltages and currents as opposed to alternating voltages and currents for transmission of energy. There are several benefits of using HVDC transmission, the most fundamental among which is the effective utilization of the physical limitations with regards to insulation and conductor cross-section. The RMS (or the effective) value of an alternating current is defined as the value that would produce the same heating effect as the one produced by a direct current of the same magnitude. Therefore, the AC RMS current rating is equal to the DC current rating for any conductor. The AC RMS, AC peak, and DC currents are related by equation (1).

$$I_{RMS} = \frac{I_m}{\sqrt{2}} = I_D \quad (1)$$

Where:

I_{RMS} = RMS value of the AC current

I_m = Peak value of the AC current

I_D = DC current

The RMS AC voltage is defined as:

$$V_{RMS} = \frac{V_m}{\sqrt{2}} \quad (2)$$

Where:

V_{RMS} = RMS value of the AC line voltage

V_m = Peak value of the AC line voltage

Insulation in a transmission system should be designed to withstand the peak voltage stress and not the RMS voltage. Therefore, the DC voltage in a DC transmission system can be equal to the peak value of the AC voltage, therefore:

$$V_D = V_m = \sqrt{2}V_{RMS} \quad (3)$$

The power transmitted over a three-phase AC line is given by:

$$P_{AC} = \sqrt{3} \times V_{RMS} \times I_{RMS} \times \text{pf} \quad (4)$$

Where:

pf = power factor = cosine of the phase angle between phase voltage and phase current in fundamental frequency operation.

The equation of power for bipolar DC operation is:

$$P_{DC} = 2 \times V_D \times I_D \quad (5)$$

Using (1) and (3) in (5):

$$P_{DC} = 2\sqrt{2} \times V_{RMS} \times I_{RMS} \quad (6)$$

Power advantage of DC over AC over the same corridor can be defined as the ratio of the two transmitted powers. From (6) and (4), we get:

$$\frac{P_{DC}}{P_{AC}} = \frac{2\sqrt{2} \times V_{RMS} \times I_{RMS}}{\sqrt{3} \times V_{RMS} \times I_{RMS} \times \text{pf}} = \frac{2\sqrt{2}}{\sqrt{3} \times \text{pf}} = \frac{1.633}{\text{pf}} \quad (7)$$

In practice, the voltage of DC system is not exactly scaled by a factor of $\sqrt{2}$ because of standardization of DC voltages. As an example, the peak value of a 400 kV line voltage is 565.7 kV which is not the DC voltage specification of a standard system. The nearest standardized DC voltage level is 550 kV. Hence, the power advantage will be reduced as follows:

$$\frac{P_{DC}}{P_{AC}} = \frac{2 \times 550}{\sqrt{3} \times 400 \times \text{pf}} = \frac{1.588}{\text{pf}} \quad (8)$$

The result in (7) is the theoretical maximum power advantage considering the limits on conductor-to-conductor voltage stress. In such a case, the conductor-to-ground insulation stress exceeds that experienced by the AC alternative. The insulator-to-ground is exposed to the phase voltage and not the line voltage in the case of AC, whereas the insulator is exposed to the pole-to-ground voltage in the case of DC. If the DC conductor-to-conductor voltage is equal to the peak of the AC line voltage, the insulator will also be exposed to the same voltage. The insulator should, therefore, be longer in the case of such DC design. Since DC voltage stress is not changing polarity like AC voltage stress, required insulator length for DC is not exactly equal to that for AC voltage. Literature states that DC stress could be as low as 86.7% of the AC stress when the DC voltage and the peak AC phase voltage are equal. This can translate into length of the insulator being shorter for DC than for the same AC voltage peak. In any case, this change requires consideration of support design, where the same support structure may have different insulator lengths for two circuits, depending upon whether the circuit is AC or DC. This may not be desirable under certain circumstances.

The other option is to calculate the voltage rating of the DC circuit by assuming the insulator length as the main constraint. In that case, equation (3) should be rewritten for phase voltage instead of the line voltage.

$$V_D = \frac{V_{\phi m}}{0.867} = \frac{\sqrt{2}V_{\phi RMS}}{0.867} = 1.6312V_{\phi RMS} \quad (9)$$

This will revise the DC power calculation as under.

$$\begin{aligned}
P_{DC} &= 2 \times V_D \times I_D = 2 \times 1.6312 V_{\phi RMS} \times I_{RMS} \\
&= 3.2624 \times \frac{V_{RMS}}{\sqrt{3}} \times I_{RMS} = 1.8836 V_{RMS} I_{RMS}
\end{aligned} \tag{10}$$

The power advantage, thus, becomes:

$$\frac{P_{DC}}{P_{AC}} = \frac{1.8836 \times V_{RMS} \times I_{RMS}}{\sqrt{3} \times V_{RMS} \times I_{RMS} \times \text{pf}} = \frac{1.0875}{\text{pf}} \tag{11}$$

The DC voltage rating of the 400-kV AC system with this option is calculated to be:

$$V_D = \frac{V_{\phi m}}{0.867} = \frac{\sqrt{2} V_{\phi RMS}}{0.867} = \frac{\sqrt{2} V_{RMS}}{0.867 \times \sqrt{3}} = 377 \text{ kV} \approx 380 \text{ kV} \tag{12}$$

It should be noted that the calculation above does not consider the larger effective creepage distance for DC than that for AC. The reason being the accumulation of contamination which is driven by the constant polarity in the case of DC stress and is not a function of electric stress in the case of AC. This can be achieved in general by changing the type of insulator or the design of insulator to accommodate larger creepage distance.

While preparing basic design of a DC transmission system, power loss in the AC/DC converters at either end of the DC circuit should also be considered. In addition, the interaction of the converters with the rest of the grid system is also important.

1.4 TRADITIONAL APPLICATIONS OF HVDC

HVAC and HVDC systems cannot be connected to each other without specialized arrangement and the combined operation of a power system containing AC and DC lines both has been traditionally viewed as troublesome. The famous war of the currents ended in favour of AC over a century ago, the reason the transmission system ended up being dominated by AC. Even then, there are situations where the use of DC is either a technical necessity or the viable economic option. These include:

- interconnection between asynchronous power systems which may or may not be operating at the same frequency;
- submarine and underground transmission over distances long enough to load AC cable thermal capacity with the inherent cable capacitive current that is a function of the cable length; and
- long-distance overhead transmission where reduced line cost for DC transmission offsets the high terminal converter station costs so that it becomes attractive compared to AC transmission. This situation is usually encountered while transmitting large amount of hydro power from a remote generating station to load centres several hundred kilometres away.

1.5 EMERGING APPLICATIONS OF HVDC

1.5.1 Power from shore for offshore consumption facilities

Offshore oil & gas facilities have to be supplied with power from cleaner onshore energy due to regulations in certain countries such as Norway. HVDC becomes the preferred option in certain cases especially where the distance to shore is large.

1.5.2 Integration of offshore generation

Offshore wind farms are being located farther from the shore as the nearshore potential is mostly developed in the regions which promote offshore generation, especially Europe. These wind farms are bigger in size to make the business case and the integration with the onshore grid is only possible with HVDC. Several projects have been realized already in Europe and elsewhere with more in the pipeline.

1.5.3 Multiterminal HVDC

In some cases, the HVDC system can connect more than two locations. Though not new, such HVDC systems were difficult to control in the past because of the older line commutated converter based HVDC systems (LCC HVDC). There are older project examples of the so-called three-terminal HVDC. After the advent of voltage source converter based HVDC (VSC HVDC), it became comparatively easier to control such systems, and these are an active research, development, and implementation area in power transmission.

There are however some real-world MTDC control challenges that need specific system level design considerations. These include:

1. **DC voltage control and power sharing:** In MTDC, more than one converter may need to participate in DC-voltage support, usually through coordinated droop-type control and a higher-level DC grid controller. Keeping DC voltage inside allowable limits while power orders change across several terminals is a core stability problem, not just a tuning detail.
2. **Fast DC fault protection:** Protection is one of the main obstacles for MTDC deployment. DC faults rise quickly, and the protection problem is more demanding than in AC because DC fault currents have no zero-crossings and because fault isolation must preserve the rest of the DC grid where possible. Reviews explicitly describe protection as a major obstacle to reliable MTDC deployment.
3. **DC breakers and fault-clearing philosophy:** Real MTDC grids often depend on DC breakers, fault blocking, or sectionalization strategies. Zhoushan project (Zhang, 2016), discussed later in the section, is frequently cited as an early project where hybrid HVDC circuit breakers were installed, while European literature still notes that DC breakers have

not yet been implemented widely in Europe and that confidence and experience remain limited.

4. **Multi-vendor interoperability:** Once VSC-terminals, controllers and protection systems are sourced from different suppliers, the challenge is no longer only related to converter control but also to system interoperability. Recent European work notes missing standards, risk of unexpected behaviour in multi-vendor multi-terminal setups, and the need for common definitions, tuning, and responsibility boundaries at the DC connection points (InterOPERA Consortium, 2024).
5. **AC/DC dynamic coupling:** MTDC terminals do not behave independently. Their AC-side controls, grid-forming or grid-following behaviour, DC-voltage support, and disturbance responses all couple through the shared DC system. The InterOPERA requirements document is explicit that AC-side and DC-side functionalities are interdependent and must be coordinated carefully (InterOPERA Consortium, 2024).
6. **Topology-dependent operation:** In MTDC, topology matters much more, than in point-to-point HVDC systems. Reliability, cost, post-fault power transfer, and operating flexibility depend on whether the network is radial, tapped, or meshed. Zhoushan case-study literature uses topology comparison itself as a design topic, which shows that the control and protection problem cannot be separated from the physical DC layout.

In conclusion, MTDC is chosen in cases where there is inherently a three-or-more-node transmission problem, and the value of one coordinated DC network outweighs the simplicity of separate two-terminal links. The trade-off is that MTDC brings a much harder control-and-protection problem: shared DC-voltage control, fast fault isolation, breaker strategy, interoperability, and coordinated AC/DC dynamics.

There are only a few multiterminal HVDC projects in operation in the world at this time. The ones referenced in this section are schemes that were conceived to solve multiple transmission grid challenges. Multiterminal HVDC schemes used for offshore power export have different technical requirements and use-case frameworks.

Case 1: Sardinia–Corsica–Italy (SACOI / SACOI 3)

A single tri-terminal HVDC scheme links mainland Italy, Corsica, and Sardinia while increasing transfer capability and preserving security of supply for both islands. SACOI 3 is explicitly described as a bipolar, multi-terminal replacement intended to make the system more efficient, reliable, and sustainable (ENTSO-E, 2016) (RTE, Terna and EDF).

The project requirement is inherently three-node: mainland Italy, Corsica, and Sardinia must all remain electrically integrated. Because Corsica is not just a tapped load but a strategic terminal with its own supply-security requirement, a tri-terminal scheme serves all three areas in one integrated asset. It is reasonable to infer that replacing this with separate point-to-point links would duplicate

converter functionality and reduce operational flexibility. The following system considerations informed the requirement for the multi-terminal HVDC link:

- Ageing existing tri-terminal link,
- Corsica needed to stay connected to the European grid,
- island security of supply, and
- need to improve renewable integration and reduce emissions

Case 2: Zhoushan MTDC

The five-terminal VSC-MTDC system strengthened supply to multiple islands and allowed flexible coordination of generation and distribution among the northern Zhoushan islands. It also used VSC-HVDC features such as controllable active/reactive power and black-start capability, which are well suited to weaker islanded systems. (National Electric Power Planning & Engineering Institute, 2019)

Zhoushan was not a simple two-end bulk-transfer problem. It involved multiple islands and sources/loads spread over the archipelago. The project literature and case-study work treat topology, reliability, and economics as central design questions, which implies the value of one coordinated multi-node DC grid rather than a set of isolated links. That is an engineering inference, but a well-supported one from the project's stated goals and topology studies. The following system considerations informed the requirement for the multi-terminal HVDC link:

- Weak island grid,
- limited local generation,
- need to improve reliability of supply to several islands, and
- need to transmit offshore wind power and coordinate spatially distributed island demand.

Case 3: Saudi Arabia–Egypt (Badr–Tabuk–Madinah)

The 3-terminal scheme allows power to flow in multiple directions among Badr, Tabuk, and Madinah and to reverse without interrupting flow. The project is positioned as a way to exchange surplus power, optimize plant usage, and address peak demand differences between Egypt and Saudi Arabia (Hitachi Energy, 2023).

The Saudi side needed two receiving/injecting nodes, not one. A three-terminal topology lets one interconnection asset serve both Tabuk and Madinah while preserving multi-directional controllability. From the published topology and stated functionality, it is reasonable to infer that two separate point-to-point links would have meant more duplicated infrastructure and less flexible use of the common corridor. The following system considerations informed the requirement for the multi-terminal HVDC link:

- Cross-border power exchange between two countries,
- need for flexible bidirectional transfer,

- need to support supply security and resilience, and
- one Egyptian node and two Saudi nodes had to exchange power over the same corridor.

All three projects are fundamentally multi-node transmission problems, not just “long distance DC is better than AC.” SACOI had to keep two islands plus the mainland in one coordinated scheme. Zhoushan had to improve service across several weakly connected islands while integrating remote generation. Saudi–Egypt had to enable cross-border exchange with two Saudi terminals and one Egyptian terminal on one HVDC interconnection.

That is the main reason MTDC was chosen instead of separate point-to-point HVDC: once more than two nodes need direct controllable participation in the same transmission task, an integrated MTDC topology can use converters and corridor assets more efficiently and can shift power among nodes more flexibly than a collection of isolated two-terminal schemes. This conclusion is partly an engineering inference, but it follows directly from the project topologies and the published emphasis on flexibility, reliability, and coordinated multi-node operation.

In practical terms, separate point-to-point links become unattractive when the problem is not “A to B,” but “A, B, and C all matter at the same time.” For SACOI, separate links would undermine the value of one tri-terminal replacement for a legacy tri-terminal asset that already serves Corsica’s connection and island supply security. For Zhoushan, separate point-to-point links would have treated the archipelago as a set of unrelated transfers, while the actual problem was coordinated reliability and generation sharing across multiple islands. The case-study literature around Zhoushan focuses heavily on topology, reliability, and economics, which is exactly where MTDC can outperform a collection of isolated links (Liu, 2018) (Wang, 2022). For Saudi–Egypt, the official description already frames the project as one multi-terminal interconnection with power flowing in multiple directions among three terminals. That is a natural fit for MTDC. Two separate links could have been built in principle, but the published material suggests the chosen topology was intended to maximize flexibility, resilience, and asset use across the shared route.

1.5.4 Embedded HVDC

An embedded HVDC link is a high-voltage direct current transmission system whose terminals are connected within the same synchronous AC power system, rather than between two asynchronously operated grids. Unlike classic “interconnector” HVDC links used to connect different frequency systems (e.g. Nordic–Continental Europe), embedded HVDC operates inside a single synchronous area but is electrically decoupled from the surrounding AC network via power electronic converters.

From the AC system’s perspective, an embedded HVDC link behaves as a controllable power injection and withdrawal, with no inherent synchronizing torque, short-circuit contribution, or fixed power–angle relationship. Modern

implementations are almost exclusively VSC, although early schemes also used LCC-HVDC technology.

Motivation for Embedded HVDC

The main motivation for embedded HVDC is to introduce controllability and capacity into a heavily loaded or constrained AC system where conventional HVAC reinforcements are limited by:

- thermal constraints,
- stability limits (angular, voltage, or dynamic),
- short-circuit strength, and
- Environmental, planning, or right-of-way restrictions.

Embedded HVDC effectively adds a “power flow control element” into the network that can move large amounts of power without increasing loop flows or compromising stability margins elsewhere.

Advantages of Embedded HVDC

1. **Precise and Fast Power Flow Control:** HVDC allows active power to be set directly by control action, independent of AC voltage angle or impedance. This enables:
 - congestion management,
 - load balancing between corridors, and
 - counterflow operation to relieve overloaded AC lines.

Unlike phase-shifting transformers (PSTs), HVDC control remains effective even under stressed or post-fault system conditions.

2. **Decoupling of Dynamic Phenomena:** Because HVDC does not transmit synchronizing torque
 - Oscillations can be damped by modulating power,
 - propagation of disturbances (angle swings, fault impacts) is reduced, and
 - weak areas of the grid can be electrically isolated from strong ones.

This is particularly valuable in systems with high penetration of power electronics–interfaced generation.

3. **Increased Transfer Capacity Without Stability Penalties:** HVAC reinforcements often hit transient or small-signal stability limits before thermal limits. Embedded HVDC bypasses this issue because
 - power transfer is not limited by rotor angle stability,
 - distance limitations of AC lines are avoided, and

- the “usable capacity” of corridors is often significantly higher.
4. **Reduced Need for AC Reinforcement:** In some cases, one embedded HVDC link can replace
 - multiple AC circuits,
 - large-scale series compensation, and
 - extensive substation upgrades

This can reduce permitting risk and environmental impact.

Disadvantages and Challenges

1. **High Capital Cost:** Converter stations remain expensive compared to AC substations. Embedded HVDC is usually justified only when
 - AC alternatives are not feasible or extremely expensive, and
 - the value of controllability is high.
2. **Complexity of System Integration:** Embedded HVDC affects
 - protection coordination,
 - power system stability studies, and
 - Grid code compliance (fault ride-through, voltage support, frequency response).

Converter controls must be carefully coordinated with existing AC controls (PSS, FACTS, PPCs).

3. **Limited Fault Contribution:** VSC-HVDC provides limited short-circuit current, which can
 - complicate protection in weak grids, and
 - require additional synchronous condensers or STATCOMs.
4. **Operational Dependency on Control Systems:** Loss or mis-operation of an embedded HVDC link can create large, sudden power imbalances. System operators must treat it as a critical asset, comparable to a large generator or transmission corridor.

Examples of Embedded HVDC Projects

1. **France–Spain HVDC (INELFE)**

Although sometimes described as an interconnector, operationally it functions as an embedded controllable corridor within a synchronous area.

- **Rating:** $2 \times 1,000$ MW, ± 320 kV
- **Configuration:** Underground HVDC link embedded within Continental Europe

- **Justification:**

- The Pyrenees posed severe environmental and planning constraints.
- AC reinforcement would have caused unacceptable loop flows in France.
- HVDC allowed controlled power exchange without destabilizing the wider European grid.

2. Western HVDC Link (Great Britain)

This is a typical example of embedded HVDC chosen over HVAC due to dynamic and planning constraints.

- **Rating:** 2,250 MW
- **Purpose:** Move power from Scotland to England within the GB synchronous system.
- **Justification:**
 - Severe north–south congestion.
 - AC reinforcements were limited by stability and public opposition.
 - HVDC provides controllable north–south transfer without increasing fault levels in England.

3. Murraylink (Australia)

- Embedded HVDC within the South Australian/NEM synchronous system
- **Justification:**
 - Long distances and weak AC networks
 - HVDC avoided complex system strengthening

4. Zhangbei DC Grid (China)

- **Configuration:** Multi-terminal VSC-HVDC embedded within the North China grid
- **Purpose:** Integrate large renewable generation and relieve AC congestion
- **Justification:**
 - Extreme short-circuit constraints
 - Need for flexible power routing
 - Demonstration of HVDC as an internal grid-forming element

1.5.5 Hybrid AC DC Transmission

This is a special case of embedded HVDC where the DC line uses the same transmission corridor and, in some cases, the same support structures used by HVAC transmission. An example case is the conversion of one circuit in double-circuit HVAC transmission line to DC. The close proximity of the AC and DC circuits requires careful consideration of several factors including electromagnetic field interaction and inter-circuit faults etc. Nonetheless, it is an effective way to enhance controllability of power flow in a grid constrained by lagging investments in expansion. One prominent example is that of Ultrahigh Voltage DC project in Germany (Amprion GmbH, 2024). The project was driven by the need for fast controllability while integrating the intermittent wind power in the north of the country to the loads in the South.

Conversion of an existing double-circuit AC line to a hybrid AC DC line is not a straightforward decision and should be considered carefully with various technical and economic aspects. The decision of such hybridization is not taken lightly and is the outcome of detailed studies by the transmission system operator. Most, if not all, system benefits provided by an embedded DC system can be provided by AC lines equipped with appropriate FACTS devices at a much lower cost. Hybridization is only considered when there is no AC alternative which satisfies all technical requirements.

This focus of this project is not to advocate for hybrid AC DC lines. We assume that such a decision has been made considering all the design choices. The focus of this project is to assess the next step in the evolution of a hybrid line. We investigate the options when there is a need for integration of load and generation growth along a hybrid AC DC line. The main differentiating factor between the two options discussed is the presence of a midpoint converter station.

1.5.6 Typical Use Cases for Hybrid AC–DC Transmission

Based on published literature and practical system studies, hybrid AC–DC transmission should be considered in the following scenarios:

1. Capacity uprating of existing double-circuit 400 kV Lines, where additional transfer capacity is required and new corridors are not feasible.
2. Long-Distance bulk power transfer (>300–400 km), particularly where stability limits constrain HVAC utilization, or where multiple compensation measures would otherwise be required.
3. Renewable energy evacuation corridors, including large wind or solar clusters, offshore or remote generation hubs, and corridors with highly variable generation profiles.
4. Weak grid interconnections, where short-circuit strength is low, voltage stability is a concern, or inverter-dominated systems are present.
5. Cross-border or inter-system links, where controlled power exchange is required, or where system dynamics differ significantly between regions.

The hybrid AC–DC configuration represents a strategic transmission enhancement option rather than a default solution. When applied in appropriate system contexts, particularly those involving long distances, constrained corridors, weak grids, or high variability generation, it can provide increased transfer capability, enhanced controllability and improved operational flexibility.

However, its adoption should be based on a case-specific technical and economic assessment, in which it is compared against a fully engineered HVAC alternative that includes all conventional mitigation measures.

1.6 INTEGRATION OF LOAD AND GENERATION INTO A HYBRID AC DC TRANSMISSION LINE

Load and generation growth along a transmission corridor can be connected to the high voltage line by tapping it using a substation. In the case of a double-circuit AC line, any or both the circuits could be tapped. This creates a node, and the line flows are not as straightforward as they would be without an intermediate node. For instance, the direction of flow from either end could be different for the two circuits. Both the circuits may be loaded as close to their capability as possible as dictated by the operational paradigm of optimal utilization of transmission assets. This is not trivial, and the loading may be limited in addition to other stability problems if intermittent and variable renewable generation such as wind and solar are connected to the tap.

In the case of a hybrid AC DC line, the AC circuit can be tapped easily because an AC substation for tapping the AC circuit is usually cheaper than a DC converter station which would be required if the DC circuit were to be tapped. Line loading and control of power flow in the system will again be severely hampered even though the converter stations at line ends for the DC circuit can help alleviate the situation.

This is where the current proposal comes in. We propose to connect the AC and DC circuits at an appropriate location along the corridor by adding a converter station. Intuition suggests that this connection may be near the midpoint of the hybrid line, however, this may not necessarily be the case. Such a connection may also help an economical and efficient spread of power over both the DC and AC circuits. This work is a preliminary investigation of the concept which will involve specification design, high-level cost estimation, and simulation studies to compare the steady-state and dynamic behaviour of the purely AC system, hybrid system without the intermediate connection, and the hybrid system with the intermediate connection.

2 System Specifications

Specifications of various system components are discussed in this chapter. Double-circuit AC transmission system as discussed in the previous chapter will form the base case. The two proposed alternatives build on these specifications in terms of voltage ratings, conductor cross-sections, and others.

2.1 BASE CASE

There is an existing single-circuit 400-kV HVAC line between Östersund and Karlstad in central Sweden. A replacement double-circuit 400-kV HVAC line named “Karlstadbenet” is being planned with the permitting process starting this year, the start of construction in 2030, and the start of operation by the winter of 2035¹.

2.2 DOUBLE-CIRCUIT AC TRANSMISSION

According to the information provided, the new line will add an overall capacity of 1000 MW to the transmission grid. The single line diagram of the alternative is shown in Figure 2-1. The proposed conductor is $3 \times 910 \text{ mm}^2$ AL59 with a current capacity of 3.231 kA at 30°C ambient temperature. The thermal capacity per circuit considering a power factor of 0.9 is approximately 2000 MW, which translates to 4 GW for the corridor. However, this is not the expected actual flow over the line considering stability limits and grid planning. We choose 1000 MW per circuit normal capacity for the time being. This value will be revised if required after simulation studies.

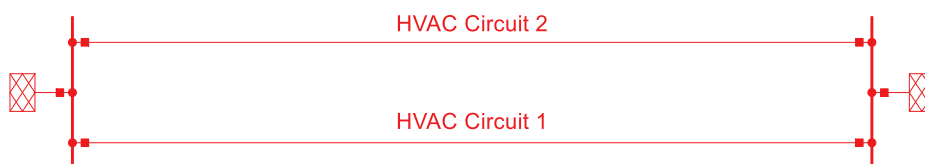


Figure 2-1: Double-circuit AC transmission

2.3 HYBRID AC DC TRANSMISSION

A hybrid line design can be chosen instead of the conventional double-circuit HVAC line. One circuit in this option will be AC and the other will be DC as shown in Figure 2-2. The normal flow over the AC circuit will be 1000 MW as chosen in the preceding section.

¹ <https://www.svk.se/utveckling-av-kraftsystemet/transmissionsnatet/transmissionsnatsprojekt/karlstadbenet/>

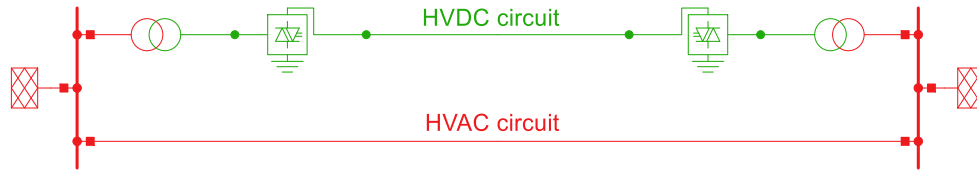


Figure 2-2: Hybrid AC DC transmission

2.3.1 DC voltage

As mentioned in chapter 1, the selected voltage for the DC circuit should be 380 kV due to the constraint of using similar length of insulators on both the circuits. This means that, in general, support structures will not need any modification in terms of their heights and weight-bearing characteristics. Insulator designs for DC are different from AC because of the need for larger creepage distances due to these being more prone to pollutant deposits. However, the cost difference between DC and AC insulators is not significant, DC being on the more expensive side. Additional cost impact will come from the requirement of converter stations at either end of the DC circuit. These converter stations require more space due to the additional AC and DC equipment associated with DC transmission.

2.3.2 DC power

The thermal power rating of the bipolar DC circuit in the hybrid line can then be calculated using (6).

$$P_{DC} = 2 \times 380 \times 3.231 = 2456 \text{ MW} \quad (13)$$

This is 456 MW more than the thermal rating with AC transmission. Therefore, the thermal capacity of the hybrid line will be 4456 MW (= 2000 + 2456). This means that the hybrid line can carry 456 MW more than the conventional double-circuit HVAC line. This equates to a theoretical power advantage of 1.114 (= 4456/4000). Put another way, the hybrid line will carry 11.4% more power than the conventional double-circuit AC line using the same insulation clearances and conductor cross-section.

As in the case of specifying normal power flow for the AC circuit, we do not use the thermal capacity as the DC line rating. The normal flow was chosen to be 50% of the thermal capacity. Using the same methodology as for AC, we arrive at a DC circuit nominal rating of 1200 MW.

2.3.3 Converter size

Even though HVDC converters at either end can provide grid support services in addition to performing their main function of converting AC power to DC for transport over the DC line, this functionality is not used extensively. We propose to use this functionality and base our converter size calculations on this premise. We take the guideline from synchronous generators for reactive power capability of the converter and substation equipment. Synchronous generators are designed to supply rated active power at worst-case power factors between 0.85 and 0.8. We choose the lower of the two values and calculate the apparent power rating:

$$S = \frac{P_{DC}}{0.8} = \frac{1200}{0.8} = 1500 \text{ MVA} \quad (14)$$

The reactive power capability of the converters will be:

$$Q = \sqrt{S^2 - P^2} = \sqrt{1500^2 - 1200^2} = 900 \text{ MVAR} \quad (15)$$

2.4 LOAD GROWTH ALONG THE HYBRID AC DC TRANSMISSION LINE

Load and generation growth along the hybrid transmission corridor should be efficiently integrated in the system. The most economical way of doing that is to tap the AC circuit in the hybrid AC DC line as shown in Figure 2-3. New nodes created in the process could be specified after detailed studies considering circuit conductor size, load, and generation at each node.

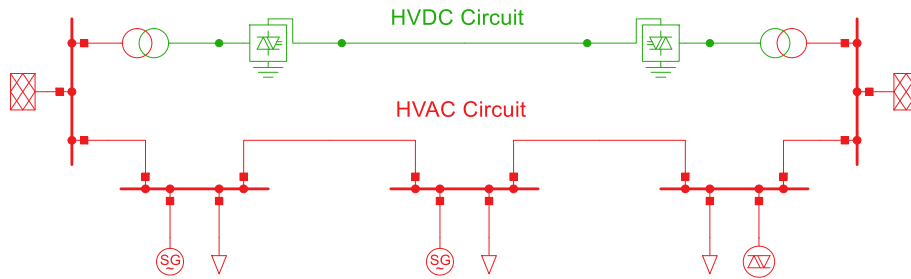


Figure 2-3: Load and generation connected to the AC circuit in the hybrid AC DC line

2.4.1 Additional substation specifications

These assumptions are preliminary and approximate at best. More accurate specifications can be calculated when more realistic generation and load development scenarios are available. The guiding principles are as under:

1. The combined maximum intake into the AC circuit from the rest of the grid at the ends of the transmission corridor should not exceed 2000 MW; of which half will enter at one end and the rest at the other end. No segment in the AC circuit should carry more than 1000 MW to stick to the limits on the power flow in the case of the ends of the AC circuit.
2. The combined maximum export from the AC circuit should not exceed 2000 MW, of which half will leave from one end and the other half from the other. No section in the AC circuit should carry more than 1000 MW to stick to the limits enforced at the ends of the corridor.

Based on the above and using engineering judgement for preliminary estimates, the three substations can each be rated at 2000 MW for a total of 6000 MW. This means that the maximum import or export per substation will not exceed 2000 MW. This too could be curtailed based on import/export scenario at other substations. It is assumed that the worst-case power factor will be 0.8. Therefore, transformer capacity will be:

$$S = \frac{P}{0.8} = \frac{2000}{0.8} = 2500 \text{ MVA} \quad (16)$$

The reactive power exchange of the individual substations with the rest of the network will be limited to:

$$Q = \sqrt{S^2 - P^2} = \sqrt{2500^2 - 2000^2} = 1500 \text{ MVAR} \quad (17)$$

2.5 HYBRID AC MTDC TRANSMISSION

This option is similar to the one described in the preceding section. The difference being the addition of a converter station near the midpoint of the line as depicted in Figure 2-4. The size of the converter station in terms of its power handling capability will be investigated with simulations, the initial guess to start the investigation of this option is equal to the size of the converter stations at the other terminals of the line. The AC side will be rated at 400 kV and the DC side at ± 380 kV. The pros and cons of this design will be highlighted during this project. There is an additional cost impact associated with the cost of equipment and land associated with the additional converter station in addition to the converter stations at either end of the line as described in the option in the preceding section.

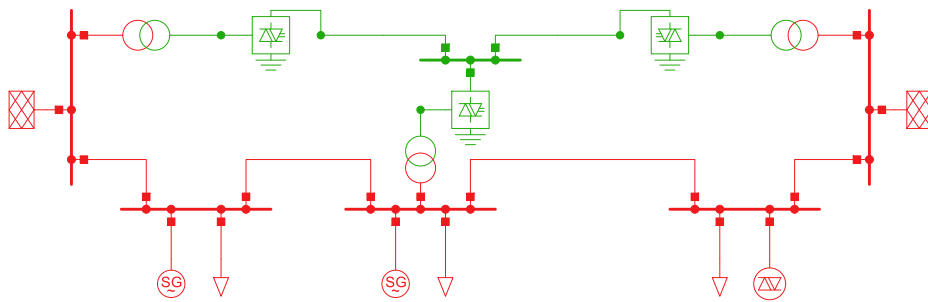


Figure 2-4: Load and generation connected to the AC circuit in the hybrid AC DC line

3 Preliminary Cost Estimates

Based on the conceptual design for the four scenarios, preliminary cost estimates were performed using the DNV in-house cost database.

3.1 INTRODUCTION TO DNV COST DATABASE

DNV has long been monitoring and benchmarking the onshore and offshore power transmission grid projects around the globe, and we maintain an in-house unit cost database based on the collected data. The database is continuously updated and calibrated with the newly announced contract values associated with such projects.

Currently the database covers the CAPEX data of the following equipment:

- HVAC substations, including transformers, switchgears, reactive compensation devices.
- HVDC converter stations.
- HVAC and HVDC overhead lines.
- HVAC and HVDC submarine and underground cables.
- Offshore platforms for AC and DC stations

3.2 METHODOLOGY AND ESTIMATION

The cost estimates were conducted in the following steps:

- Bill of Material compilation
- Unit cost estimate
- CAPEX summary and analysis

Using the design specifications as detailed in previous chapters, the bill of materials for the four scenarios and the relevant unit costs are listed in Table 3-1, Table 3-2, Table 3-3, and Table 3-4, respectively for the four alternatives.

The base case (Table 3-1) is a double-circuit 400 kV HVAC overhead lines with the transfer capacity of 2000 MW, as shown in Figure 2-1.

Table 3-1 Bill of Material for the Base case

Device	Voltage (kV)	Rating (MVA/MW)	Qty or Length (km)	CAPEX (MEUR/unit)	Total CAPEX [M€]
HVAC AIS	400	1000	4	3.37	13.5
HVAC double circuit line	400	2000	460	1.15	529.0
Sum					542.5

The second case (Table 3-2) features hybrid AC/DC lines as shown in Figure 2-2, with a 400 kV HVAC overhead line running in parallel with a 380 kV HVDC line,

the two converter stations are of full-bridge VSC MMC configuration in order to facilitate fast DC fault clearance. It is also worth noting that the DC line is assumed to be constructed together with the parallel AC circuit as a double circuit 400 kV HVAC line.

Table 3-2 Bill of Material for the Hybrid AC/DC Transmission

Device	Voltage (kV)	Rating (MVA/MW)	Qty or Length (km)	CAPEX (MEUR/unit)	Total CAPEX [M€]
HVAC AIS	400	1000	2	3.37	13.5
FB VSC Converter Station	380	1500	2	488.4	976.8
HVAC double circuit line	400	2000	460	1.15	529.0
Sum					1512.5

The third alternative (Table 3-3) is a variation of the hybrid AC/DC transmission system by adding AC taps in order to accommodate the expected load and generation growth along the route, as shown in Figure 2-3.

Table 3-3 Bill of Material for the Hybrid AC/DC Transmission with AC taps

Device	Voltage (kV)	Rating (MVA/MW)	Qty or Length (km)	CAPEX (MEUR/unit)	Total CAPEX [M€]
HVAC AIS	400	1000	5	3.37	16.9
FB VSC Converter Station	380	1500	2	488.4	976.8
HVAC double circuit line	400	2000	460	1.15	529.0
Sum					1522.7

The third alternative (Table 3-4) is another variation of the hybrid AC/DC transmission system by adding a 3rd HVDC converter station in order to accommodate the expected load growth along the route, as shown in Figure 2-4.

Table 3-4 Bill of Material for the Hybrid AC/DC Transmission with DC tap

Device	Voltage (kV)	Rating (MVA/MW)	Qty or Length (km)	CAPEX (MEUR/unit)	Total CAPEX [M€]
HVAC AIS	400	1000	5	3.37	16.9
FB VSC Converter Station	380	1500	3	488.4	1465.2

Device	Voltage (kV)	Rating (MVA/MW)	Qty or Length (km)	CAPEX (MEUR/unit)	Total CAPEX [M€]
HVAC double circuit line	400	2000	460	1.15	529.0
Sum					2011.1

3.3 COMPARISON AND DISCUSSION

The CAPEX breakdown for the four alternatives as shown above are also visualized in Figure 3-1.

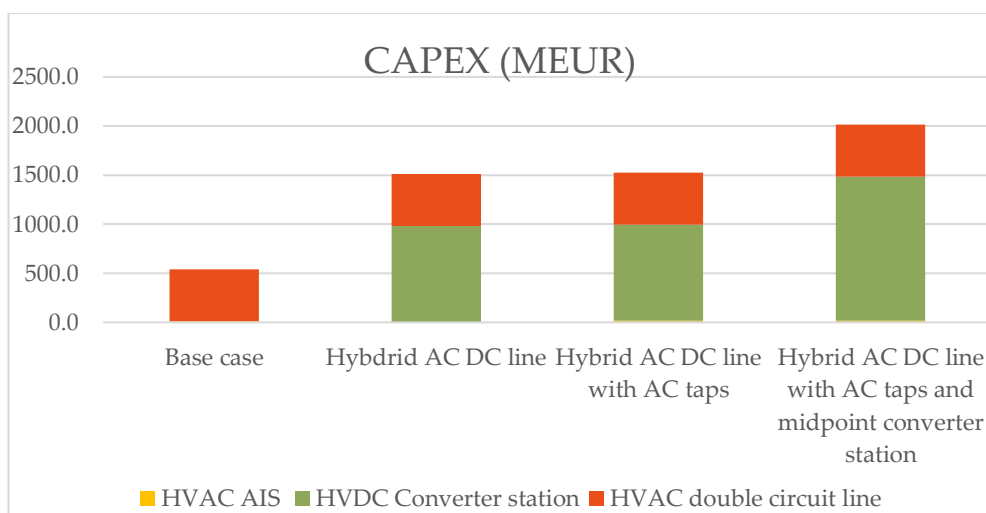


Figure 3-1: CAPEX comparison of the four alternatives

It can be seen that:

- All the three Hybrid AC/DC cases are significantly more expensive than the base case (pure AC).
- In AC cases the cost is dominated by the HVAC overhead line cost
- The “Hybrid AC DC Line” and “Hybrid AC DC line with AC tap” are rather similar in terms of total CAPEX, since the major difference is the additional mid-point substation in the latter case, the cost of such mid-point substation is insignificant as compared with the HVDC converter stations.

Furthermore, it is worth noting that

- the comparison on CAPEX should be complemented by the operational benefit brought by HVDC systems,

- In the cost estimate, we assumed that one circuit of the double circuit 400 kV HVAC overhead line can be operated under ± 380 kV HVDC system, no additional conversion costs were considered.
- The cost data used were exclusively based on DNV's in-house cost database, which are considered a market average. No efforts have been made to adapt to the Swedish market.
- HVDC supply market is stressed, careful, and timely planning and OEM engagements are necessary in order to avoid project delays and cost overruns.

4 RMS Simulations

This section presents the simulation setup, study cases, assumptions, simulation results, and conclusions for the studies performed in positive-sequence RMS domain.

An important consideration during the simulation process is the uncertainty associated with how the transmission system at either end of the corridor develops in the future. The actual systems may not need some of the benefits that are discussed in the simulation cases in the succeeding sections. For instance, high fault current may not be a concern if the system is not highly meshed. Also, weak grid conditions may not be encountered if the system is expected to continue to develop as a strong system. Another example is that of low inertia scenario which may not be encountered in a system dominated by synchronous generators.

4.1 SIMULATION MODEL

The system configurations presented in section 2 are modelled in DIgSILENT PowerFactory. This subsection includes the modelling approach, assumptions, model limitations, and model configurations that have been used for simplified, static load flow simulations.

4.1.1 Network representation

The RMS simulation studies in this report focus primarily on the normal operation capabilities and performance of the transmission corridor itself, rather than the surrounding grid. As such, a simplified network representation is selected where an overlying 400 kV network at each side of the transmission corridor is modelled as a Thevenin equivalent voltage source. To simplify the load flow analysis, the following assumptions are applied to the network equivalents:

- The transmission system equivalents connected to the north and south sides of the transmission corridor are referred to as “North” and “South” respectively.
- The North network equivalent (normally sending end, unless otherwise specified) acts as the swing bus in the network solution, controlling the local voltage magnitude to 1 p.u. and busbar voltage angle to 0°. The North equivalent will act as a generator that adjusts the active power flow across the transmission corridor based on the load and generation setpoints in the remainder of the simulation model.
- The South network equivalent (normally receiving end, unless otherwise specified) acts as a constant voltage source, fixing the local voltage magnitude to 1 p.u., where the active power consumption or generation is fixed and selected based on the studied case. The resulting voltage phase angle following a load flow calculation at the South network equivalent can therefore be used to assess the angular stability characteristics of the transmission corridor. If the North and South busbars are not connected

directly via an AC circuit (i.e. during contingency), the South busbar must also act as a swing bus, considering the limitation that both ends are represented as Thevenin equivalents.

- Any generator connected to the transmission corridor via AC circuit taps control their local voltage to unity, acting as a reactive power reserve.
- Since both the North and South network equivalents as well as generators are controlling their local voltage setpoints, the need for additional, separate reactive power compensation devices for voltage control is limited in the model. However, considering that this is an important aspect of long-distance high voltage high power transfer, it is assumed that such devices are built into the network equivalents or placed alongside generators and partake in the reactive power levels of the Thevenin equivalents and equipment necessary to obtain unity voltage at the corridor terminals and taps.

4.1.2 Double-Circuit AC Transmission

The base-case for this report is defined in section 2.2 as a double-circuit AC transmission corridor. This is currently the most common implementation of long-distance high voltage high power transmission, following the relative simplicity of the design, robustness, and low comparable costs.

The simulation model is presented in Figure 4-1. The North and South network equivalents of the transmission corridor are indicated with dashed boxes. The nominal voltage level at the network equivalents is set to 400 kV and the total transmission distance is 460 km. The circuits are modelled as towers, taking the physical characteristics of the conductors in consideration, including mutual coupling, to calculate the electrical properties of resistance, inductance, and capacitance. The circuits use a default configuration from the DIgSILENT PowerFactory equipment library where the conductor current carrying capacity is set to 3.231 kA per circuit to mimic similar conductors which are typically used by the Swedish TSO Svenska kraftnät. The conductors are placed in a vertical arrangement as presented in Figure 4-2 to provide a tower and circuit configuration that can be applied both for the AC and DC circuit arrangement without changing the physical properties of the transmission corridor.

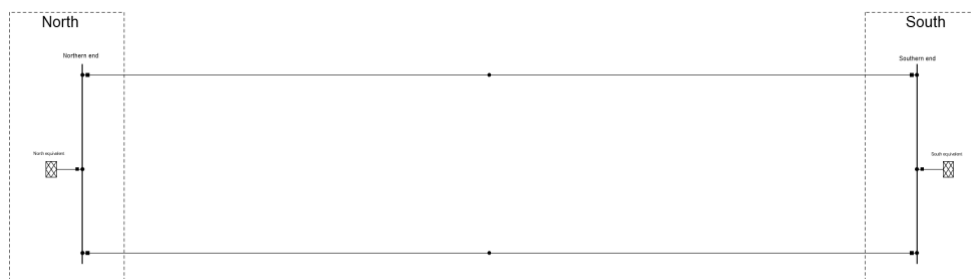


Figure 4-1: Double-circuit AC transmission corridor concept in DIgSILENT PowerFactory

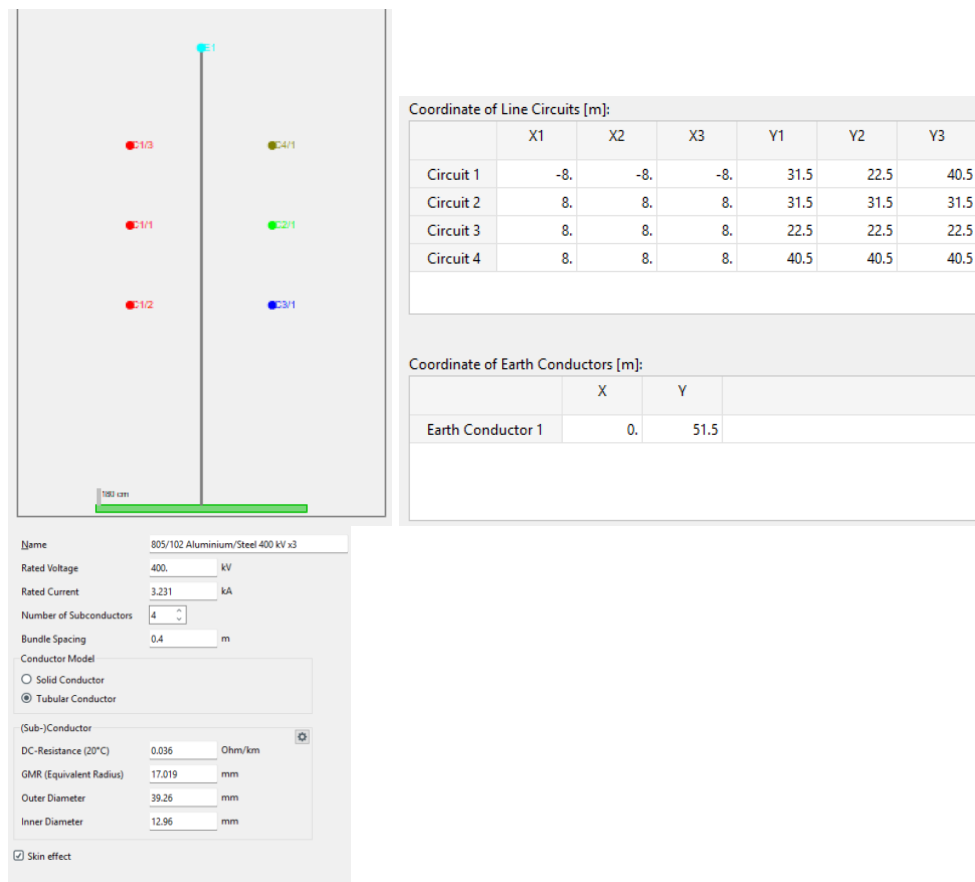


Figure 4-2: Tower and circuit arrangement

The double-circuit HVAC solution studied in this section is assumed to be as simple as possible, without any additional equipment to improve the power transfer capabilities. The reactive power supplied by the Thevenin sources connected at either end provides an indication of the reactive equipment which should be connected at each end for the connection to be technically viable. As is the case with long transmission lines, angular stability constraints are encountered before the thermal capacity is reached in the example model.

4.1.3 Hybrid AC DC Transmission

The transmission corridor presented in section 4.1.2 is expanded upon by substituting one of the AC circuits with a DC link. The configuration of the network equivalents, transmission corridor length and the parallel AC circuit remain the same. The simulation model in DIgSILENT PowerFactory is presented in Figure 4-3.

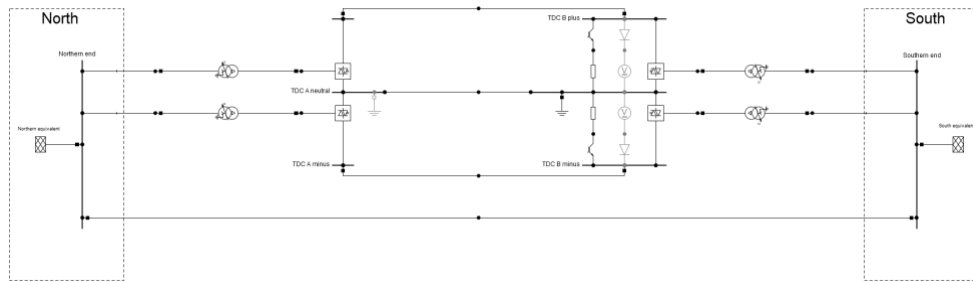


Figure 4-3: Hybrid AC DC transmission corridor concept in DigSILENT PowerFactory

The DC link is modelled using an existing MMC bipole MNR HVDC equipment template available within the DigSILENT PowerFactory equipment library. The rating of the HVDC equipment necessary for the static load flow simulation study is selected and tuned based on the calculated case set-up from section 2.3. The HVDC link consists of the following equipment specifications for this purpose:

Converters

The HVDC link converters are placed at the North and South transmission corridor ends and are modelled as full-bridge MMC converters. Based on the calculations from section 2.3, the two converter poles are selected to have a maximum active power transfer of 600 MW each at a power factor of 0.8, leading to 750 MVA apparent power rating per pole of the converters. The maximum total transfer capacity at each terminal is therefore 1200 MW, 1500 MVA. These limits are considered for all study cases and may not be exceeded in any operational scenario, to provide a realistic limitation of the DC link transfer capacity.

The converters are controlled as follows:

- One converter station always operates in active power-AC voltage control to provide controllability of the active power flow through the DC link and reactive compensation to control AC voltage.
- One converter station always operates in DC voltage-AC voltage control to maintain the DC and AC voltage levels at its DC and AC sides respectively.
- The converters can operate at a maximum modulation index of unity without saturating.

Voltage levels

The calculations from section 2.3 indicate that the selected DC voltage level of 380 kV can be adequately achieved and controlled with a connecting AC voltage level of 230 kV. Therefore, the AC voltage connecting the DC link to the overall system is selected to 230 kV. Such a configuration ensures that the modulation index of the converters is maintained close to unity for normal operating scenarios. Constraints related to important phenomena such as insulation strength are not included in this section of the analysis.

Transformers

To facilitate a connecting AC voltage level of 230 kV, step-down transformers must be integrated at each end of the HVDC link to transform the 400 kV voltage level to the desirable 230 kV level. One transformer is connected to each arm of the HVDC link, and the rating is selected to match that of the converter size (750 MVA).

DC conductors

To facilitate a realistic scenario, the DC circuit is placed on the same tower as the AC circuit and uses the same vertical conductor arrangement. The DC conductor is assumed to have the same current carrying capacity as the AC circuit (3.231 kA) and is arranged as follows:

- The positive polarity circuit is selected as the top conductor.
- The neutral return is selected as the middle conductor.
- The negative polarity circuit is selected as the bottom conductor.

4.1.4 Load growth along the hybrid AC DC transmission corridor

An important aspect of planning network infrastructure is foreseeing how the transmission system may develop in the coming years. The rapidly increasing integration of renewable sources and large power-electronic integrated loads introduces new possibilities and challenges in network planning.

One such aspect of network planning is the possibility of connecting additional load and generation along existing transmission corridors. The capabilities of such an expansion are investigated by adding the capability of feeding or consuming power at three locations across the remaining AC circuit. This is realized by tapping the AC circuit and attaching additional loads and generation at those locations. In this simulation study, the taps are assumed equally spaced with 115 km between each tap and the North and South ends of the corridor. Of course, the location of these taps can vary based on specific requirements as the network develops. The simulation model in DlgSILENT PowerFactory is presented in Figure 4-4. The magnitude of load and generation that can be reasonably connected over the transmission corridor is estimated via simplified simulation studies and presented as part of the simulation scope.

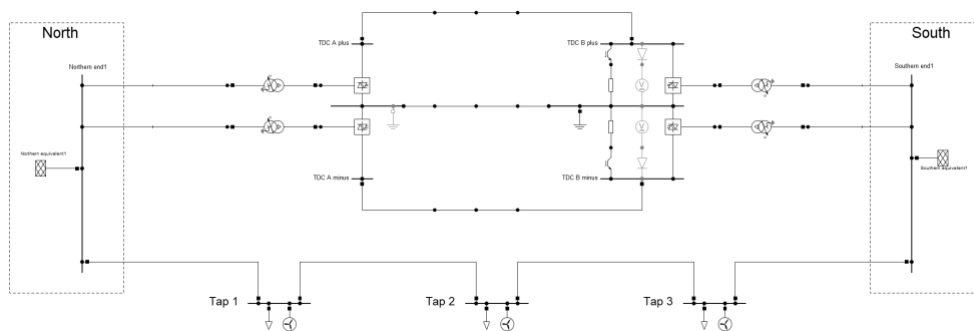


Figure 4-4: Hybrid AC DC transmission corridor concept with added taps in DlgSILENT PowerFactory

4.1.5 Load growth along the hybrid AC DC transmission corridor with midpoint converter station

The situation depicted in the preceding section puts the responsibility of integration of new load and generation solely on the AC circuit because it is easier to connect AC systems to AC systems. However, the limitations of such an arrangement where the second circuit is not contributing too much are obvious. The DC circuit can help improve power exchange at the ends of the corridor to some extent with that solution.

The second circuit being a DC circuit can contribute significantly if there is a connection between the two circuits at another location. This allows the DC link to support the AC circuit during demanding network conditions while also providing additional operational capabilities of the transmission corridor, for example, during outages on the tapped AC circuit. To investigate the benefits of such a configuration, the simulation model in 4.1.4 is expanded by adding a third converter station at the physical midpoint between the northern and southern ends. This creates a direct connection between the DC link and the AC circuit through the converter station at the midpoint tap. The simulation model is presented in Figure 4-5.

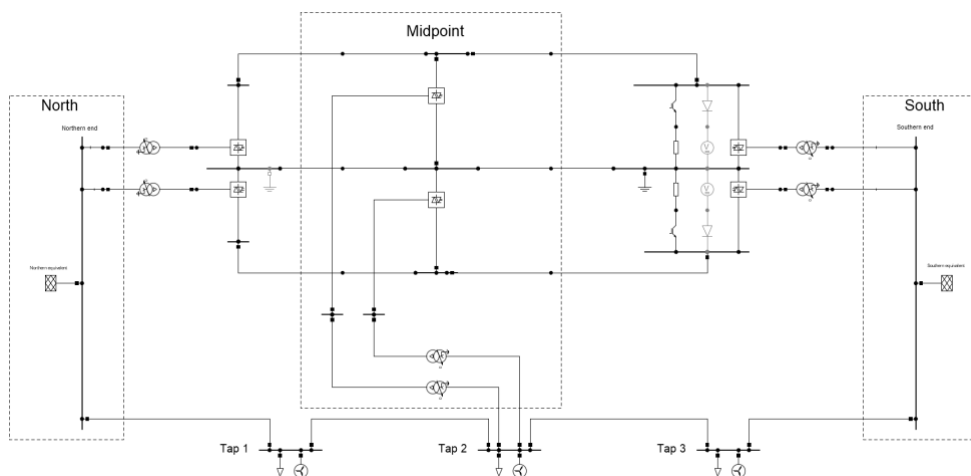


Figure 4-5: Hybrid AC DC transmission corridor concept with added taps and midpoint converter station in DigSILENT PowerFactory

The midpoint converter station is set to control the active power flow from the DC link to the AC circuit tap, as well as the local AC side voltage. This creates additional flexibility in the operation of the transmission corridor which is analyzed as part of the cases studied. It should be noted that the operational mode of the midpoint converter station will depend on the present network conditions and the natural power flow direction between the corridor ends. For example, if there is an outage on either the North or South converter station, the control mode of the midpoint converter may have to be changed to allow further operation of the DC link.

4.2 RMS STUDY CASES

Multiple cases are studied to investigate the steady-state load-flow performance of the model configurations presented in section 4.1. An overview of the studied cases together with the applicable configurations and purpose is provided in Table 4-1.

The first set of cases (1-3) intends to provide a high-level comparison of the uncompensated double-circuit HVAC and hybrid AC DC transmission concepts. The latter case (4) presents several simulations, comparing the performance of the hybrid AC DC transmission concept with and without a midpoint converter station under various assumptions.

Table 4-1: RMS study cases

Case number	Case name	Models used
1	Transport capacity & stability margins	Double-circuit AC Hybrid AC DC
2	Outage of converter pole	Double-circuit AC Hybrid AC DC
3	Outage of AC circuit	Double-circuit AC Hybrid AC DC
4	Growth of load and generation over the transmission corridor	Hybrid AC DC Hybrid AC DC with midpoint converter

The following assumptions are made for all study cases:

- The maximum transfer capacity of any AC circuit is assumed to be 1000 MW. It should be noted that this is much less than the thermal capacity of the lines.
- The maximum active power transfer capacity of the DC link is 1200 MW, with 600 MW per converter pole.
- Both network equivalents and local generators are assumed to be equipped with sufficient reactive power reserves to maintain unity voltage at each bus.

4.3 TRANSPORT CAPACITY AND STABILITY MARGINS

This study case aims to investigate how the transport capacity and stability margins are impacted by replacing one of the AC circuits in the double-circuit AC transmission configuration with an HVDC link. A set of load flow cases are studied where the loading of the transmission corridor is adjusted to investigate how the performance of the transmission corridor is influenced by the DC link.

The simulation case is studied for the transmission corridor configurations presented in section 4.1.2 (double-circuit AC configuration) and section 4.1.3 (hybrid AC DC configuration).

The analysis is performed by fixating the voltage angle at each end of the transmission corridor to force a power flow from the swing bus (North) to the load bus (South). As such, the resulting active and reactive power levels for fixed relative phase angle difference across the transmission corridor can be compared for the double-circuit AC and hybrid AC DC solutions. Examples of simulated cases are provided in Table 4-2 and Table 4-3. The hybrid solution allows a controllable power flow by adjusting the active power setpoint of the DC link. Several cases are studied for the hybrid solution to investigate how the control of the DC link impacts the relative phase angle difference between the North and South ends of the corridor.

Table 4-2: Transport capacity and stability margins – double circuit AC transmission

$\varphi_{\text{receiving}}$ [°]**	P_{sending} [MW]*	Q_{sending} [Mvar]*	$P_{\text{receiving}}$ [MW]*	$Q_{\text{receiving}}$ [Mvar]*
-10	511	-317	508	-281
-20	1010	-203	997	-130
-30	1481	-3	1452	102
-40	1911	275	1861	411

Table 4-3: Transport capacity and stability margins – hybrid AC DC transmission

$\varphi_{\text{receiving}}$ [°]**	DC Power [MW]*	P_{sending} [MW]*	Q_{sending} [Mvar]*	$P_{\text{receiving}}$ [MW]*	$Q_{\text{receiving}}$ [Mvar]*
-10	600	833	137	804	108
-10	800	1033	128	999	96
-20	800	1261	77	1221	26
-20	1000	1461	65	1414	-23
-30	1000	1677	-25	1621	-97
-30	1200	1877	-41	1813	-115
-40	1000	1874	-150	1806	-239
-40	1200	2074	-166	1998	-257

* Positive sign indicates injection of power

** Negative sign indicates lagging angle in relation to the reference angle

The results indicate that the double-circuit AC configuration requires significant reactive power compensation resources at the transmission corridor ends to maintain the voltage levels.

The DC link introduces flexibility in the power flow across the transmission corridor. The hybrid AC DC link configuration requires less reactive power infeed and/or absorption from the sending and receiving ends compared to the double AC circuit configuration, suggesting that the introduced voltage controllability of the DC link can support the voltage characteristics of the corridor. For the stability margins, it can be observed that the DC link can, under specific circumstances, significantly reduce the relative voltage phase angle between the North and South ends, and, thus, improves angular stability in the system. However, this only holds true if the DC link active power can be controlled such that a significantly reduced

power flow across the AC circuit can be achieved compared to the double AC circuit configuration for the same power flow. If the DC link is unable to significantly reduce the active power flow across the AC circuit, the DC link cannot always support in phase angle improvements. A graphical comparison of the relative phase angle difference between North and South is presented in Figure 4-6, indicating how the phase angle is impacted by how much of the load is being transported via the DC link.

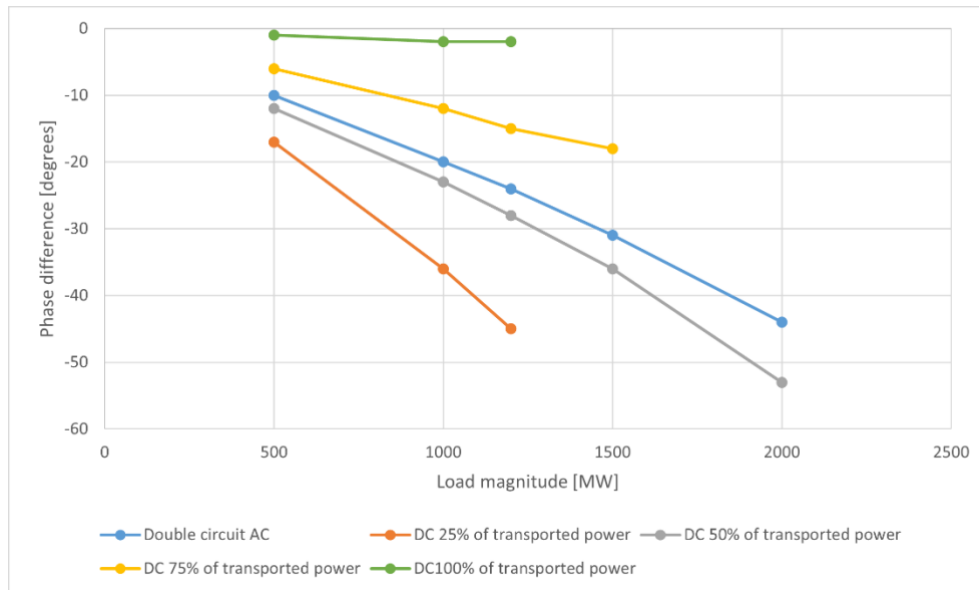


Figure 4-6: Phase difference between North and South ends for different load flow scenarios

4.4 OUTAGE OF CONVERTER POLE

Contingency analysis for N-1 operation is an integral part of system planning to ensure safe and reliable operation of the transmission system even during outage of important system components. Component outages resulting in N-1 operation will undoubtedly occur, both scheduled due to necessary maintenance of important system equipment and during unpredictable events such as natural component degradation (failure) and disturbances. Such operating scenarios are therefore paramount for studying the capabilities of the system under stressed conditions.

This scenario compares the operational capabilities of the hybrid AC DC configuration with the traditional double-circuit AC configuration under the assumption that one of the converter poles of the DC link is out of operation. Therefore, the HVDC link can export a maximum of 600 MW, compared to the full capacity of 1200 MW.

For this scenario, the double-circuit AC configuration is assumed to operate without any component failure. Section 4.3 suggests that a maximum system loading of 1450 MW could be reached before exceeding a relative voltage angle difference of 30 degrees between the sending and receiving terminals. Furthermore, Section 4.3 indicates that the most significant voltage angle improvement is found if the HVDC link can carry a significant portion of the

transmission corridor load. The HVDC link is in this case controlled to carry its maximum active power of 600 MW. Considering a case where the 30-degree voltage angle is maintained, the resulting maximum system loading for this case is simulated to 1225 MW, suggesting that for high load scenarios, the limited transfer capacity of HVDC will reduce the capability of improving the angular stability. For situations of lower power flow, the DC link can still provide benefits for angular stability if operated to do so.

4.5 OUTAGE OF AC CIRCUIT

The contingency scenario when one AC circuit is out of service presents an interesting case as the remaining corridor becomes inherently different for the double circuit AC configuration and the hybrid AC DC concept. In the first case, the transmission corridor will operate under similar conditions as prior to the disturbance, with a reduced transfer capacity. In the latter case, the hybrid solution will become a pure DC link connection, which significantly changes the electrical coupling between the corridor terminals and the power flow characteristics and controllability between them.

In this case, a relative voltage angle difference between the North and South ends of 30 degrees is considered as a base-case power transfer. For the double-circuit AC configuration, this is achieved with a system loading of approximately 710 MW, indicating a significantly reduced transfer capacity considering voltage angle stability constraints compared to the normal operating scenario with two parallel circuits, as expected.

The same analysis becomes interesting for the AC circuit outage when the remaining circuit is a HVDC link. The HVDC link itself is not constrained by the relative voltage angle difference between the sending and receiving end in the same way as a traditional AC circuit. This is because the power flow over the DC link is driven by the controllers of the HVDC converters, rather than the angular difference between the transmission corridor endpoint busbars, as is the case for the traditional AC power transfer. The HVDC link can theoretically continue to feed the maximum active power transfer allowed by the converters - 1200 MW, during this outage.

Reservation should be made for the simulation following the simplified model setup which is being used in this report. All study cases assume that the network equivalents on each side of the transmission corridor are electrically decoupled, apart from the connection via the corridor itself. This impacts on the study results, considering that transmission constraints in other parts of the system are not taken into consideration. The results only indicate the impact on the transmission corridor itself, rather than the full system. In addition, the contingency case with only a remaining DC connection means that the North and South ends in the simplified model will be completely decoupled, with different reference busbars. The example case in this report considers a DC link within a synchronous system, not an interconnector. This means that the electrical decoupling of reference machines in the model will not provide a true representation of the real-world electrical coupling between the transmission corridor ends. However, for the

purpose of static load flow simulations, the impact of this is limited, considering that the HVDC converter controllers have no knowledge of whether the two terminals are within the same synchronous area or not, as well as that the surrounding system outside of the transmission corridor is neglected. Other concerns regarding the controllability of the DC link are not studied here, but should be considered for detailed, case-specific studies during the system design-phase.

4.6 GROWTH OF LOAD AND GENERATION OVER THE TRANSMISSION CORRIDOR

Another important aspect of planning network infrastructure is foreseeing how the transmission system may develop in the coming years. The rapidly increasing integration of renewable sources and large power-electronic integrated loads introduces new possibilities and challenges for network planning.

The hybrid AC DC configuration has presented potential benefits for both voltage stability as well as angular stability compared to the simple, non-compensated double-circuit AC configuration. In this scenario, the hybrid AC DC configuration is expanded upon by investigating the possibilities of expanding transmission corridor by adding three taps on the AC circuit where both load and generation can be directly attached. This creates a more complex situation with regards to the power flow solution, considering that all power will no longer necessarily flow in the same direction from one end to the other. The simulation models presented in section 4.1.4 and section 4.1.5 are used for this purpose. The two models are identical with one differentiator – the latter introduces a third converter station located at the electrical midpoint between the North and South ends, which allows power exchange between the DC circuit and the tapped AC circuit, which otherwise is not possible for such a hybrid system.

The operational benefits offered by the third converter station depend significantly on the characteristics of the surrounding network as well as the location of the added load and generation. Therefore, multiple scenarios are studied considering the capabilities of the surrounding network combined with realistic network contingencies.

For the study cases in this section, the following additional assumptions are made:

- The AC circuit segments can carry a maximum of 1000 MW each.
- The generation connected at the three taps supports local system voltages by injection or absorbing reactive power, to eliminate the need for adding additional compensation devices in the simulation model.
- All loads connected to the AC circuit taps have a power factor of unity. Reactive power levels are maintained by the generators only.
- Power can be fed or absorbed simultaneously from the North and South end irrespective of power magnitude.

- Load or generation is attached to only one of the AC circuit taps at a time. More specific configurations with load and generation at multiple busbars at the same time are not studied in detail, considering that it introduces a large variety of cases and would create very specific scenarios. Voltage control is always applied at all taps and network equivalents.

A graphical representation of the component outages is provided in Figure 4-7. The red, orange and green text indicates the contingency cases.

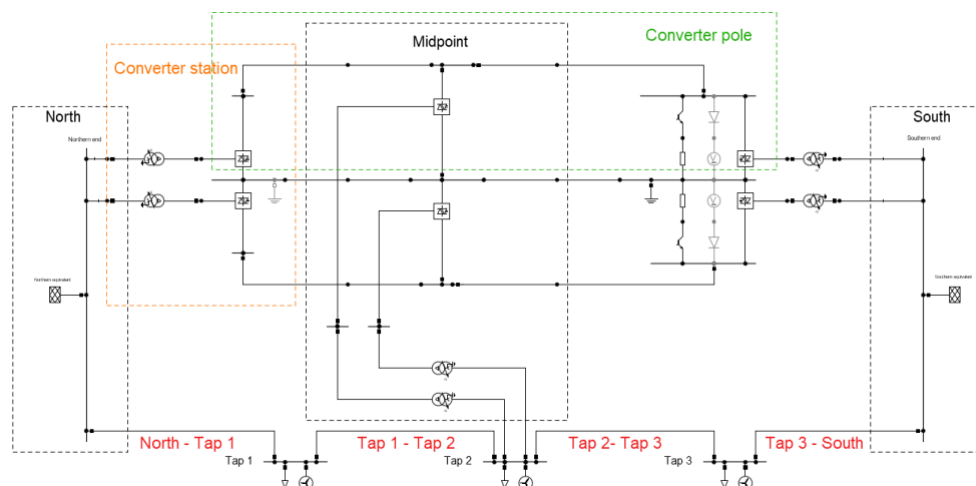


Figure 4-7: Overview of contingency cases

4.6.1 Maximum load – without midpoint converter

The approximate maximum load (net power exchange) which can be connected to the taps along the AC circuit without a third midpoint converter station following the assumed transfer capacity constraints, along with the resulting phase angles and reactive power requirements are presented for Tap 1, Tap 2 and Tap 3 in Table 4-4 to Table 4-12.

Table 4-4: Voltage angle – load connected at tap 1 – without midpoint converter station

Operating scenario	Bus angle [°]					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	0	-11	0	11	23	North
De-loaded system	0	0	0	0	0	North
N-1 outage North – Tap 1	-	-34	-23	-11	0	South
N-1 outage Tap 1 – Tap 2	0	-11	-	-	-	North
N-1 outage Tap 2 – Tap 3	0	-11	-11	-	-	North
N-1 outage Tap 3 – South	0	-11	-11	-11	-	North
N-1 outage Converter station	0	-11	0	11	22	North
N-1 outage Converter pole	0	-11	0	11	22	North

Table 4-5: Active power – load connected at tap 1 - without midpoint converter station

Operating scenario	Bus active power [MW] (positive sign = consuming)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	-2079	2000	0	0	0	North
De-loaded system	-20	0	0	0	0	North
N-1 outage North – Tap 1	-1070	1000	0	0	0	South
N-1 outage Tap 1 – Tap 2	-1029	1000	0	0	0	North
N-1 outage Tap 2 – Tap 3	-1029	1000	0	0	0	North
N-1 outage Tap 3 – South	-1029	1000	0	0	0	North
N-1 outage Converter station	-1031	2000	0	0	-1015	North
N-1 outage Converter pole	-1031	2000	0	0	-1015	North

Table 4-6: Reactive power – load connected at tap 1 - without midpoint converter station

Operating scenario	Bus reactive power [Mvar] (positive sign = injecting)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	14	212	122	126	69	North
De-loaded system	-39	-78	-78	-78	-38	North
N-1 outage North – Tap 1	0	106	122	126	69	South
N-1 outage Tap 1 – Tap 2	14	106	-39	-78	-38	North
N-1 outage Tap 2 – Tap 3	14	67	-39	-39	-38	North
N-1 outage Tap 3 – South	14	67	-78	-39	-1	North
N-1 outage Converter station	18	212	114	117	15	North
N-1 outage Converter pole	16	212	118	121	16	North

Table 4-7: Voltage angle – load connected at tap 2 – without midpoint converter station

Operating scenario	Bus angle [°]					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	0	-11	-23	-12	0	North
N-1 outage North – Tap 1	-	-23	-23	-11	0	South
N-1 outage Tap 1 – Tap 2	-	-	-23	-11	0	South
N-1 outage Tap 2 – Tap 3	0	-11	-23	-	-	North
N-1 outage Tap 3 – South	0	-11	-23	-23	-	North
N-1 outage Converter station	0	-12	-23	-12	-1	North
N-1 outage Converter pole	0	-11	-23	-12	0	North

Table 4-8: Active power – load connected at tap 2 – without midpoint converter station

Operating scenario	Bus active power [MW] (positive sign = consuming)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	-2078	0	2000	0	0	North
N-1 outage North – Tap 1	-1060	0	1000	0	0	South
N-1 outage Tap 1 – Tap 2	-1060	0	1000	0	0	South
N-1 outage Tap 2 – Tap 3	-1038	0	1000	0	0	North
N-1 outage Tap 3 – South	-1038	0	1000	0	0	North
N-1 outage Converter station	-1037	0	2000	0	-1010	North
N-1 outage Converter pole	-1037	0	2000	0	-1010	North

Table 4-9: Reactive power – load connected at tap 2 – without midpoint converter station

Operating scenario	Bus reactive power [Mvar] (positive sign = injecting)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	17	126	212	119	64	North
N-1 outage North – Tap 1	0	39	67	122	67	South
N-1 outage Tap 1 – Tap 2	-39	-39	106	122	67	South
N-1 outage Tap 2 – Tap 3	16	122	106	-39	-38	North
N-1 outage Tap 3 – South	16	122	67	-39	1	North
N-1 outage Converter station	18	130	212	115	14	North
N-1 outage Converter pole	17	126	212	119	15	North

Table 4-10: Voltage angle – load connected at tap 3 – without midpoint converter station

Operating scenario	Bus angle [°]					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	0	-11	-23	-34	-23	North
N-1 outage North – Tap 1	-	-11	-11	-11	0	South
N-1 outage Tap 1 – Tap 2	-	-	-11	-11	0	South
N-1 outage Tap 2 – Tap 3	-	-	-	-11	0	South
N-1 outage Tap 3 – South	0	-11	-23	-34	-	North
N-1 outage Converter station	0	-11	-23	-34	-23	North
N-1 outage Converter pole	0	-11	-23	-34	-22	North

Table 4-11: Active power – load connected at tap 3 – without midpoint converter station

Operating scenario	Bus active power [MW] (positive sign = consuming)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	-2078	0	0	2000	0	North
N-1 outage North – Tap 1	-1050	0	0	1000	0	South
N-1 outage Tap 1 – Tap 2	-1050	0	0	1000	0	South
N-1 outage Tap 2 – Tap 3	-1050	0	0	1000	0	South
N-1 outage Tap 3 – South	-1048	0	0	1000	0	North
N-1 outage Converter station	-1027	0	0	2000	-1020	North
N-1 outage Converter pole	-1026	0	0	2000	-1020	North

Table 4-12: Reactive power– load connected at tap 3 – without midpoint converter station

Operating scenario	Bus reactive power [Mvar] (positive sign = injecting)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	17	126	123	212	64	North
N-1 outage North – Tap 1	0	-39	-78	67	65	South
N-1 outage Tap 1 – Tap 2	-39	-39	-39	67	64	South
N-1 outage Tap 2 – Tap 3	-39	-78	-39	106	64	South
N-1 outage Tap 3 – South	17	126	122	106	1	North
N-1 outage Converter station	17	126	122	212	15	North
N-1 outage Converter pole	15	122	118	212	16	North

4.6.2 Maximum generation – without midpoint converter

The approximate maximum generation (net power exchange) which can be connected to the taps along the AC circuit without a third midpoint converter station following the assumed transfer capacity constraints, along with the resulting phase angles and reactive power requirements are presented for Tap 1, Tap 2 and Tap 3 in Table 4-13 to Table 4-21.

Table 4-13: Voltage angle – generation connected at tap 1 – without midpoint converter station

Operating scenario	Bus angle [°]					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	0	11	0	-11	-22	North
N-1 outage North – Tap 1	-	33	22	11	0	South
N-1 outage Tap 1 – Tap 2	0	11	-	-	-	North
N-1 outage Tap 2 – Tap 3	0	11	11	-	-	North
N-1 outage Tap 3 – South	0	11	11	11	-	North
N-1 outage Converter station	0	11	0	-11	-23	North
N-1 outage Converter pole	0	11	0	-11	-22	North

Table 4-14: Active power – generation connected at tap 1 – without midpoint converter station

Operating scenario	Bus active power [MW] (positive sign = consuming)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	970	-2000	0	0	975	North
N-1 outage North – Tap 1	20	-1000	0	0	974	South
N-1 outage Tap 1 – Tap 2	971	-1000	0	0	0	North
N-1 outage Tap 2 – Tap 3	971	-1000	0	0	0	North
N-1 outage Tap 3 – South	971	-1000	0	0	0	North
N-1 outage Converter station	980	-2000	0	0	975	North
N-1 outage Converter pole	980	-2000	0	0	975	North

Table 4-15: Reactive power – generation connected at tap 1 – without midpoint converter station

Operating scenario	Bus reactive power [Mvar] (positive sign = injecting)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	104	26	116	112	101	North
N-1 outage North – Tap 1	0	13	115	112	101	South
N-1 outage Tap 1 – Tap 2	104	13	-39	-78	-38	North
N-1 outage Tap 2 – Tap 3	104	-26	-39	-39	-38	North
N-1 outage Tap 3 – South	104	-26	-78	-39	1	North
N-1 outage Converter station	101	26	120	116	103	North
N-1 outage Converter pole	104	26	116	112	100	North

Table 4-16: Voltage angle – generation connected at tap 2 – without midpoint converter station

Operating scenario	Bus angle [°]					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	0	11	22	11	0	North
N-1 outage North – Tap 1	-	22	22	11	0	South
N-1 outage Tap 1 – Tap 2	-	-	22	11	0	South
N-1 outage Tap 2 – Tap 3	0	11	22	-	-	North
N-1 outage Tap 3 – South	0	11	22	22	-	North
N-1 outage Converter station	0	11	22	11	0	North
N-1 outage Converter pole	0	11	22	11	0	North

Table 4-17: Active power – generation connected at tap 2 – without midpoint converter station

Operating scenario	Bus active power [MW] (positive sign = consuming)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	975	0	-2000	0	980	North
N-1 outage North – Tap 1	0	0	-1000	0	962	South
N-1 outage Tap 1 – Tap 2	0	0	-1000	0	962	South
N-1 outage Tap 2 – Tap 3	962	0	-1000	0	0	North
N-1 outage Tap 3 – South	962	0	-1000	0	0	North
N-1 outage Converter station	975	0	-2000	0	980	North
N-1 outage Converter pole	975	0	-2000	0	980	North

Table 4-18: Reactive power – generation connected at tap 2 – without midpoint converter station

Operating scenario	Bus reactive power [Mvar] (positive sign = injecting)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	97	108	26	122	107	North
N-1 outage North – Tap 1	0	-39	-26	115	103	South
N-1 outage Tap 1 – Tap 2	-39	-39	13	115	103	South
N-1 outage Tap 2 – Tap 3	102	115	13	-39	-38	North
N-1 outage Tap 3 – South	102	115	-26	-39	1	North
N-1 outage Converter station	100	112	26	118	105	North
N-1 outage Converter pole	102	116	26	114	102	North

Table 4-19: Voltage angle – generation connected at tap 3 – without midpoint converter station

Operating scenario	Bus angle [°]					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	0	11	22	33	22	North
N-1 outage North – Tap 1	-	11	11	11	0	South
N-1 outage Tap 1 – Tap 2	-	-	11	11	0	South
N-1 outage Tap 2 – Tap 3	-	-	-	11	0	South
N-1 outage Tap 3 – South	0	11	22	33	-	North
N-1 outage Converter station	0	11	22	33	22	North
N-1 outage Converter pole	0	11	22	33	22	North

Table 4-20: Active power – generation connected at tap 3 – without midpoint converter station

Operating scenario	Bus active power [MW] (positive sign = consuming)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	955	0	0	-2000	990	North
N-1 outage North – Tap 1	0	0	0	-1000	971	South
N-1 outage Tap 1 – Tap 2	0	0	0	-1000	971	South
N-1 outage Tap 2 – Tap 3	0	0	0	-1000	971	South
N-1 outage Tap 3 – South	954	0	0	-1000	0	North
N-1 outage Converter station	965	0	0	-2000	990	North
N-1 outage Converter pole	970	0	0	-2000	990	North

Table 4-21: Reactive power– generation connected at tap 3 – without midpoint converter station

Operating scenario	Bus reactive power [Mvar] (positive sign = injecting)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	100	112	116	26	105	North
N-1 outage North – Tap 1	0	-39	-78	-26	105	South
N-1 outage Tap 1 – Tap 2	-39	-39	-39	-26	105	South
N-1 outage Tap 2 – Tap 3	-39	-78	-39	13	105	South
N-1 outage Tap 3 – South	100	112	115	13	1	North
N-1 outage Converter station	-98	109	112	26	108	North
N-1 outage Converter pole	100	110	114	26	105	North

4.6.3 Maximum load – with midpoint converter

The approximate maximum load (net power exchange) which can be connected to the taps along the AC circuit with a third midpoint converter station following the assumed transfer capacity constraints, along with the resulting phase angles and reactive power requirements are presented for Tap 1, Tap 2 and Tap 3 in Table 4-22 to Table 4-30.

Table 4-22: Voltage angle – load connected at tap 1 – with midpoint converter station

Operating scenario	Bus angle [°]					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	0	-11	0	0	-1	North
De-loaded system	0	0	0	0	0	North
N-1 outage North – Tap 1	-	-11	0	0	0	South
N-1 outage Tap 1 – Tap 2	0	-11	-	-	-	North
N-1 outage Tap 2 – Tap 3	0	-11	0	-	-	North
N-1 outage Tap 3 – South	0	-11	0	0	-	North
N-1 outage Converter station	0	-11	0	11	22	North
N-1 outage Converter pole	0	-11	0	11	23	North

Table 4-23: Active power – load connected at tap 1 – with midpoint converter station

Operating scenario	Bus active power [MW] (positive sign = consuming)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	-2060	2000	0	0	0	North
De-loaded system	-30	0	0	0	0	North
N-1 outage North – Tap 1	-1050	1000	0	0	0	South
N-1 outage Tap 1 – Tap 2	-1039	1000	0	0	0	North
N-1 outage Tap 2 – Tap 3	-2059	2000	0	0	0	North
N-1 outage Tap 3 – South	-2059	2000	0	0	0	North
N-1 outage Converter station	-1027	2000	0	0	-1030	North
N-1 outage Converter pole	-1022	2000	0	0	-1030	North

Table 4-24: Reactive power– load connected at tap 1 – with midpoint converter station

Operating scenario	Bus reactive power [Mvar] (positive sign = injecting)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	14	212	29	-77	-35	North
De-loaded system	-39	-78	-76	-78	-38	North
N-1 outage North – Tap 1	0	106	27	-77	-37	South
N-1 outage Tap 1 – Tap 2	14	106	-38	-78	-38	North
N-1 outage Tap 2 – Tap 3	-11	212	69	-39	-38	North
N-1 outage Tap 3 – South	-11	212	31	-39	1	North
N-1 outage Converter station	17	-212	121	127	19	North
N-1 outage Converter pole	15	212	122	125	17	North

Table 4-25: Voltage angle – load connected at tap 2 – with midpoint converter station

Operating scenario	Bus angle [°]					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	0	-11	-22	-11	1	North
N-1 outage North – Tap 1	-	-23	-23	-11	0	South
N-1 outage Tap 1 – Tap 2	-	-	-23	-11	0	South
N-1 outage Tap 2 – Tap 3	0	-11	-22	-	-	North
N-1 outage Tap 3 – South	0	-11	-22	-22	-	North
N-1 outage Converter station	0	-11	-23	-12	-1	North
N-1 outage Converter pole	0	-11	-22	-11	0	North

Table 4-26: Active power – load connected at tap 2 – with midpoint converter station

Operating scenario	Bus active power [MW] (positive sign = consuming)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	-2202	0	3150	0	-1030	North
N-1 outage North – Tap 1	-1200	0	2150	0	-1014	South
N-1 outage Tap 1 – Tap 2	-1200	0	2150	0	-1014	South
N-1 outage Tap 2 – Tap 3	-2214	0	2150	0	0	North
N-1 outage Tap 3 – South	-2214	0	2150	0	0	North
N-1 outage Converter station	-1032	0	3150	0	-2190	North
N-1 outage Converter pole	-1605	0	2550	0	-1010	North

Table 4-27: Reactive power – load connected at tap 2 – with midpoint converter station

Operating scenario	Bus reactive power [Mvar] (positive sign = injecting)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	13	116	276	129	19	North
N-1 outage North – Tap 1	0	-39	131	123	17	South
N-1 outage Tap 1 – Tap 2	-39	-39	170	123	17	South
N-1 outage Tap 2 – Tap 3	15	121	169	-39	-38	North
N-1 outage Tap 3 – South	15	121	130	-39	1	North
N-1 outage Converter station	18	128	275	116	61	North
N-1 outage Converter pole	13	117	238	117	14	North

Table 4-28: Voltage angle – load connected at tap 3 – with midpoint converter station

Operating scenario	Bus angle [°]					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	0	-11	-23	-34	-23	North
N-1 outage North – Tap 1	-	0	0	-11	0	South
N-1 outage Tap 1 – Tap 2	-	-	0	-11	0	South
N-1 outage Tap 2 – Tap 3	0	0	0	-11	0	South
N-1 outage Tap 3 – South	0	-11	-23	-34	-	North
N-1 outage Converter station	0	-11	-23	-34	-23	North
N-1 outage Converter pole	0	-11	-22	-33	-22	North

Table 4-29: Active power – load connected at tap 3 – with midpoint converter station

Operating scenario	Bus active power [MW] (positive sign = consuming)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	-2089	0	0	2000	0	North
N-1 outage North – Tap 1	-1050	0	0	2000	-1010	South
N-1 outage Tap 1 – Tap 2	-1050	0	0	2000	-1010	South
N-1 outage Tap 2 – Tap 3	-1050	0	0	1000	0	South
N-1 outage Tap 3 – South	-1047	0	0	1000	0	North
N-1 outage Converter station	-1026	0	0	2000	-1030	North
N-1 outage Converter pole	-1021	0	0	2000	-1030	North

Table 4-30: Reactive power – load connected at tap 3 – with midpoint converter station

Operating scenario	Bus reactive power [Mvar] (positive sign = injecting)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	19	131	128	212	62	North
N-1 outage North – Tap 1	0	-39	-31	212	12	South
N-1 outage Tap 1 – Tap 2	-39	-39	64	212	12	South
N-1 outage Tap 2 – Tap 3	-39	-78	-38	106	64	South
N-1 outage Tap 3 – South	17	126	124	106	10	North
N-1 outage Converter station	17	126	123	212	15	North
N-1 outage Converter pole	15	120	117	212	17	North

4.6.4 Maximum generation – with midpoint converter

The approximate maximum generation (net power exchange) which can be connected to the taps along the AC circuit with a third midpoint converter station following the assumed transfer capacity constraints, along with the resulting phase angles and reactive power requirements are presented for Tap 1, Tap 2 and Tap 3 in Table 4-31 to Table 4-39.

Table 4-31: Voltage angle – generation connected at tap 1 – with midpoint converter station

Operating scenario	Bus angle [°]					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	0	11	0	-11	-23	North
N-1 outage North – Tap 1	-	33	22	11	0	South
N-1 outage Tap 1 – Tap 2	0	11	-	-	-	North
N-1 outage Tap 2 – Tap 3	0	11	0	-	-	North
N-1 outage Tap 3 – South	0	11	0	0	-	North
N-1 outage Converter station	0	11	1	-11	-23	North
N-1 outage Converter pole	0	11	0	-11	-22	North

Table 4-32: Active power – generation connected at tap 1 – with midpoint converter station

Operating scenario	Bus active power [MW] (positive sign = consuming)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	960	-2000	0	0	975	North
N-1 outage North – Tap 1	30	-1000	0	0	974	South
N-1 outage Tap 1 – Tap 2	961	-1000	0	0	0	North
N-1 outage Tap 2 – Tap 3	952	-2000	0	0	989	North
N-1 outage Tap 3 – South	952	-2000	0	0	989	North
N-1 outage Converter station	969	-2000	0	0	975	North
N-1 outage Converter pole	975	-2000	0	0	975	North

Table 4-33: Reactive power – generation connected at tap 1 – with midpoint converter station

Operating scenario	Bus reactive power [Mvar] (positive sign = injecting)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	101	26	121	116	103	North
N-1 outage North – Tap 1	0	13	116	112	101	South
N-1 outage Tap 1 – Tap 2	104	13	-38	-78	-38	North
N-1 outage Tap 2 – Tap 3	102	26	139	-39	10	North
N-1 outage Tap 3 – South	102	26	100	-39	49	North
N-1 outage Converter station	99	26	125	120	106	North
N-1 outage Converter pole	105	26	116	112	100	North

Table 4-34: Voltage angle – generation connected at tap 2 – with midpoint converter station

Operating scenario	Bus angle [°]					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	0	11	22	11	0	North
N-1 outage North – Tap 1	-	22	22	11	0	South
N-1 outage Tap 1 – Tap 2	-	-	22	11	0	South
N-1 outage Tap 2 – Tap 3	0	11	22	-	-	North
N-1 outage Tap 3 – South	0	11	22	22	-	North
N-1 outage Converter station	0	11	22	11	0	North
N-1 outage Converter pole	0	11	22	11	0	North

Table 4-35: Active power – generation connected at tap 2 – with midpoint converter station

Operating scenario	Bus active power [MW] (positive sign = consuming)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	989	0	-3200	0	2130	North
N-1 outage North – Tap 1	0	0	-2200	0	2137	South
N-1 outage Tap 1 – Tap 2	0	0	-2200	0	2137	South
N-1 outage Tap 2 – Tap 3	981	0	-2200	0	1156	North
N-1 outage Tap 3 – South	981	0	-2200	0	1156	North
N-1 outage Converter station	984	0	-3200	0	2145	North
N-1 outage Converter pole	986	0	-2600	0	1550	North

Table 4-36: Reactive power – generation connected at tap 2 – with midpoint converter station

Operating scenario	Bus reactive power [Mvar] (positive sign = injecting)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	103	118	74	112	164	North
N-1 outage North – Tap 1	0	-39	23	115	166	South
N-1 outage Tap 1 – Tap 2	-39	-39	62	115	166	South
N-1 outage Tap 2 – Tap 3	-101	-115	-62	39	-26	North
N-1 outage Tap 3 – South	101	115	23	-39	64	North
N-1 outage Converter station	102	116	74	114	166	North
N-1 outage Converter pole	103	117	50	114	132	North

Table 4-37: Voltage angle – generation connected at tap 3 – with midpoint converter station

Operating scenario	Bus angle [°]					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	0	11	22	33	22	North
N-1 outage North – Tap 1	-	0	0	11	0	South
N-1 outage Tap 1 – Tap 2	-	-	0	11	0	South
N-1 outage Tap 2 – Tap 3	-	-	-	11	0	South
N-1 outage Tap 3 – South	0	11	22	33	-	North
N-1 outage Converter station	0	11	22	33	22	North
N-1 outage Converter pole	0	11	22	33	22	North

Table 4-38: Active power – generation connected at tap 3 – with midpoint converter station

Operating scenario	Bus active power [MW] (positive sign = consuming)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	945	0	0	-2000	990	North
N-1 outage North – Tap 1	0	0	0	-2000	1942	South
N-1 outage Tap 1 – Tap 2	0	0	0	-2000	1942	South
N-1 outage Tap 2 – Tap 3	0	0	0	-1000	961	South
N-1 outage Tap 3 – South	944	0	0	-1000	0	North
N-1 outage Converter station	965	0	0	-2000	980	North
N-1 outage Converter pole	960	0	0	-2000	990	North

Table 4-39: Reactive power– generation connected at tap 3 – with midpoint converter station

Operating scenario	Bus reactive power [Mvar] (positive sign = injecting)					Reference busbar
	North	Tap 1	Tap 2	Tap 3	South	
Normal operation	100	112	117	26	105	North
N-1 outage North – Tap 1	0	-39	94	26	151	South
N-1 outage Tap 1 – Tap 2	-39	-39	133	26	151	South
N-1 outage Tap 2 – Tap 3	-39	-78	-38	13	105	South
N-1 outage Tap 3 – South	100	112	116	13	1	North
N-1 outage Converter station	98	109	113	26	107	North
N-1 outage Converter pole	100	112	116	26	104	North

4.6.5 Result summary – power levels

The simulated results are summarized in a graphical format to provide a direct comparison of the performance of the two system configurations for all studied cases. The active power levels found for each scenario are presented in Figure 4-8 to Figure 4-21.

The results indicate that during normal operation (N-0) of the transmission corridor, the midpoint converter station offers limited advantages in improving the load or generation that can be connected to the AC circuit of the transmission corridor itself. Considering the assumed constraints of AC circuit transfer capacity, the additional converter station can only improve the power transfer to or from the busbar where the converter station itself is connected. The additional load or generation will be largely dependent on the size of the converter, which in this case is assumed to be 1200 MW.

Contingency operation (N-1) shows stronger improvements with the midpoint converter station. The midpoint converter allows a significantly higher power exchange to the AC circuit taps during component outages. More specifically, the added converter station can naturally improve load levels if the faulted component is one segment or more away from the load location. This occurs because the converter station creates an additional path for power to flow, meaning that an AC circuit segment outage will not always result in a single-point power flow infeed. Instead, the DC link can be utilized to create a second flow path, allowing a higher power transfer capability that is not only limited by the transfer capacity of the remaining AC circuit. The midpoint converter station allows the DC link to directly support the active power exchange with the AC circuit taps. However, it must be

highlighted that this finding assumes that the power flow solution of the network allows the DC link to operate in such a way that it can support load and generation on the AC circuit taps, which may not always be the case due to wider system constraints.

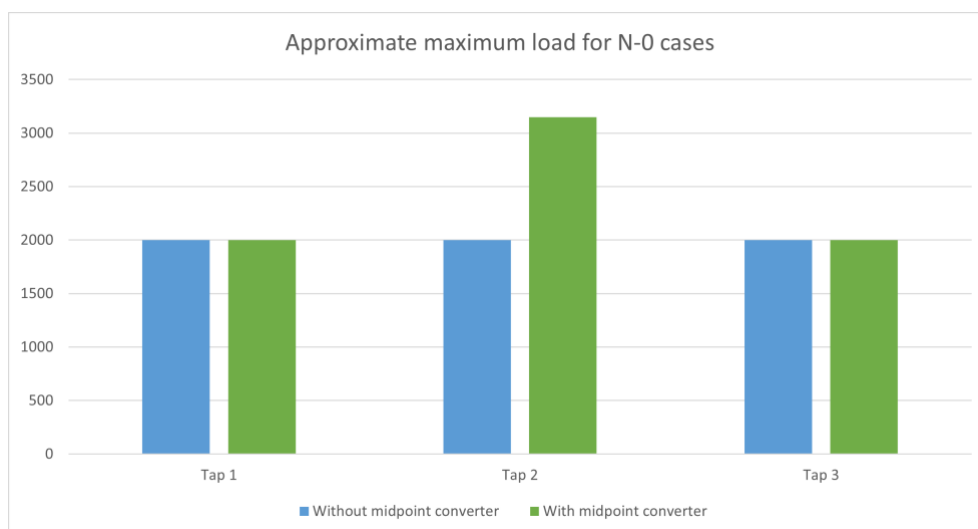


Figure 4-8: Comparison of load levels – normal operation

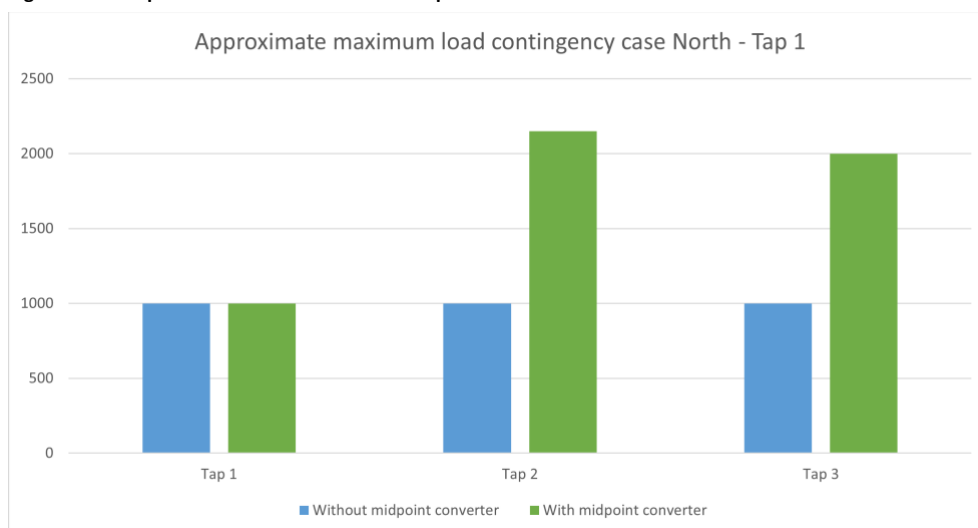


Figure 4-9: Comparison of load levels – contingency case North – Tap 1

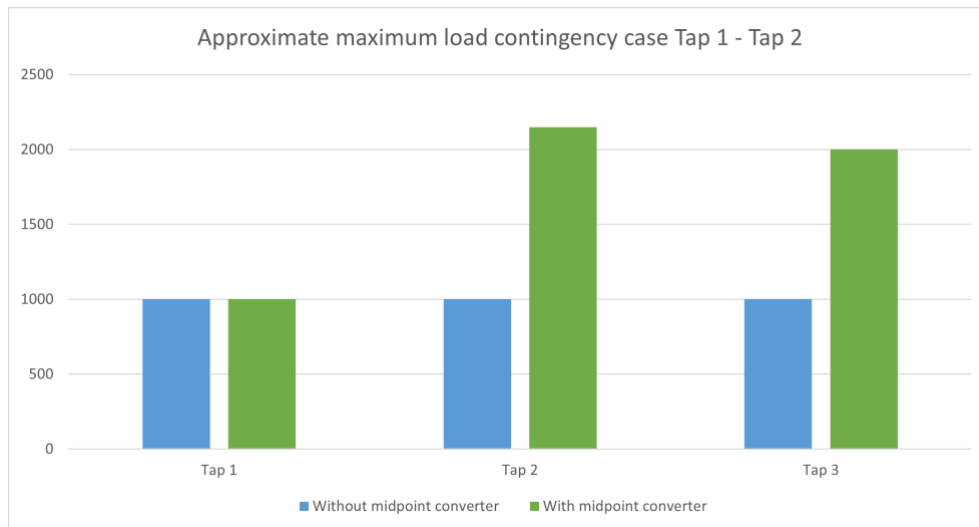


Figure 4-10: Comparison of load levels – contingency case Tap 1 – Tap 2

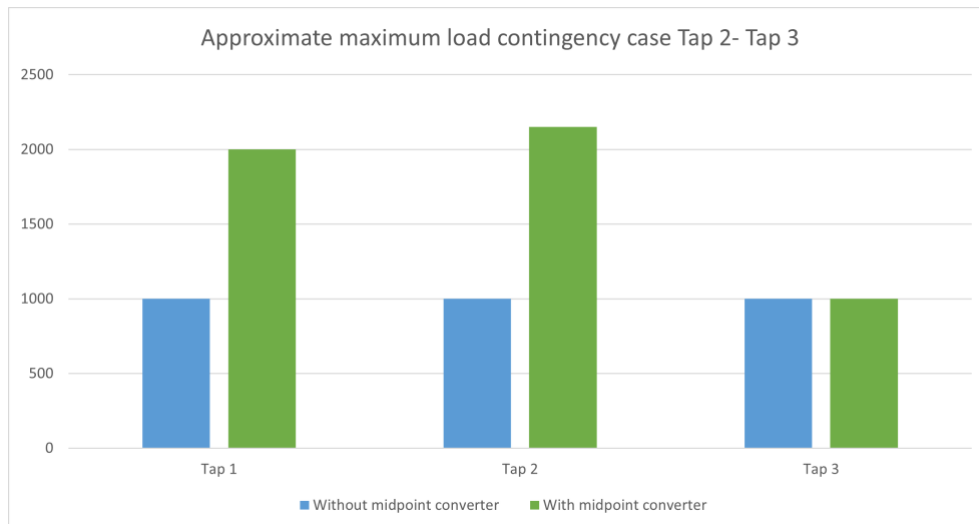


Figure 4-11: Comparison of load levels – contingency case Tap 2 – Tap 3

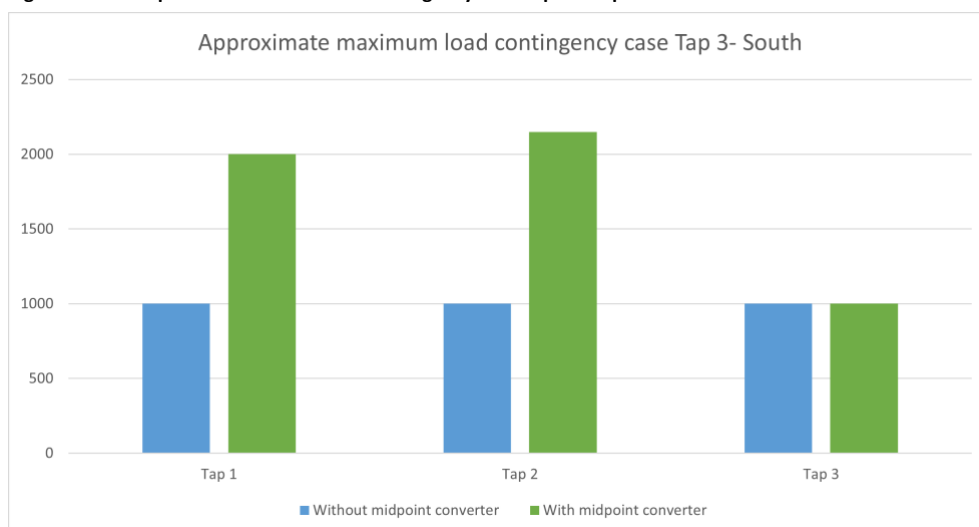


Figure 4-12: Comparison of load levels – contingency case Tap 3 – South

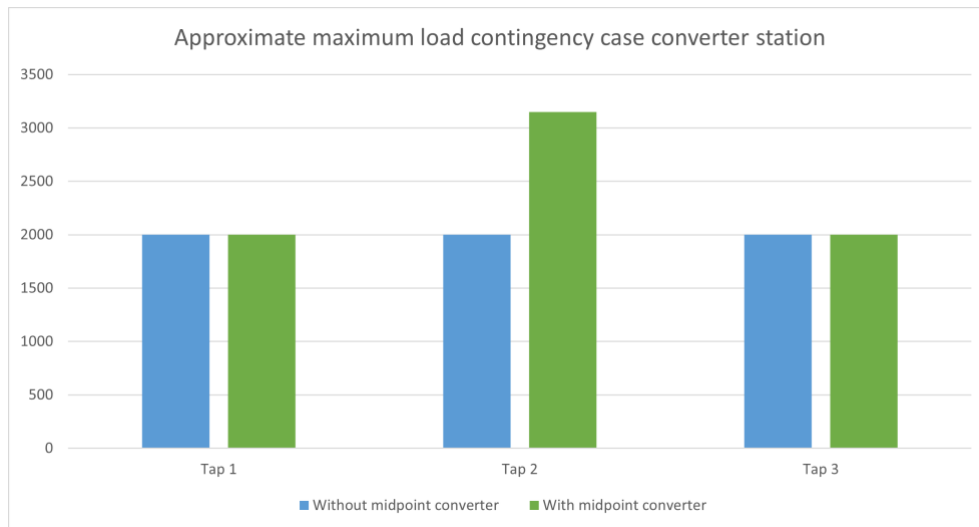


Figure 4-13: Comparison of load levels – contingency case converter station

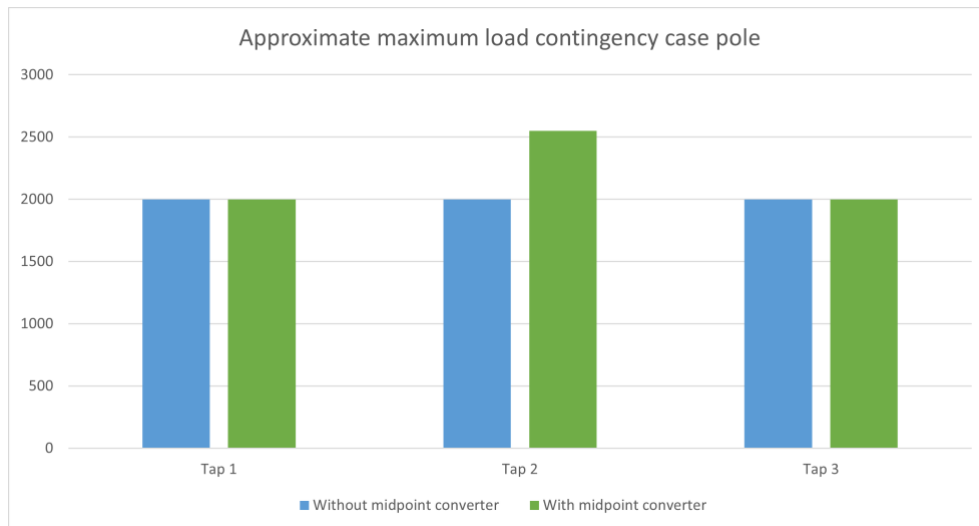


Figure 4-14: Comparison of load levels – contingency case converter pole

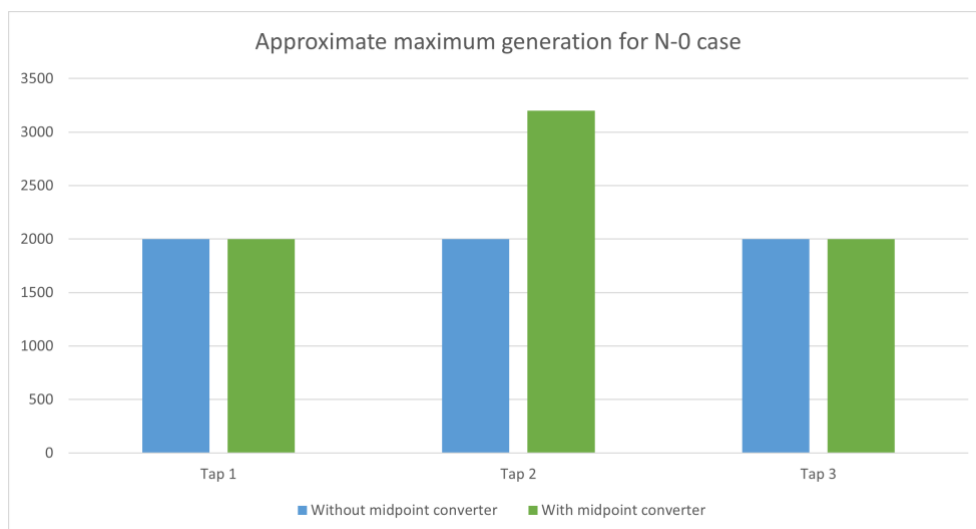


Figure 4-15: Comparison of generation levels – normal operation

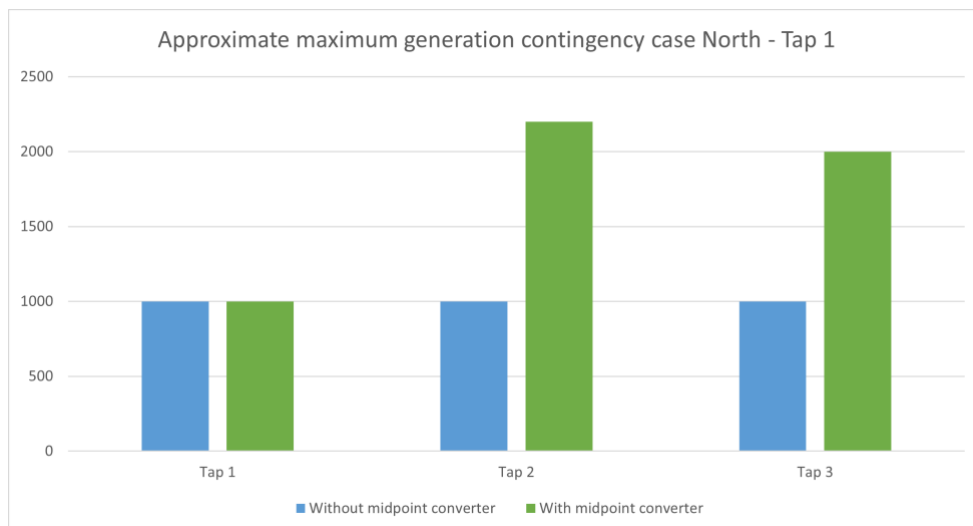


Figure 4-16: Comparison of generation levels – contingency case North – Tap 1

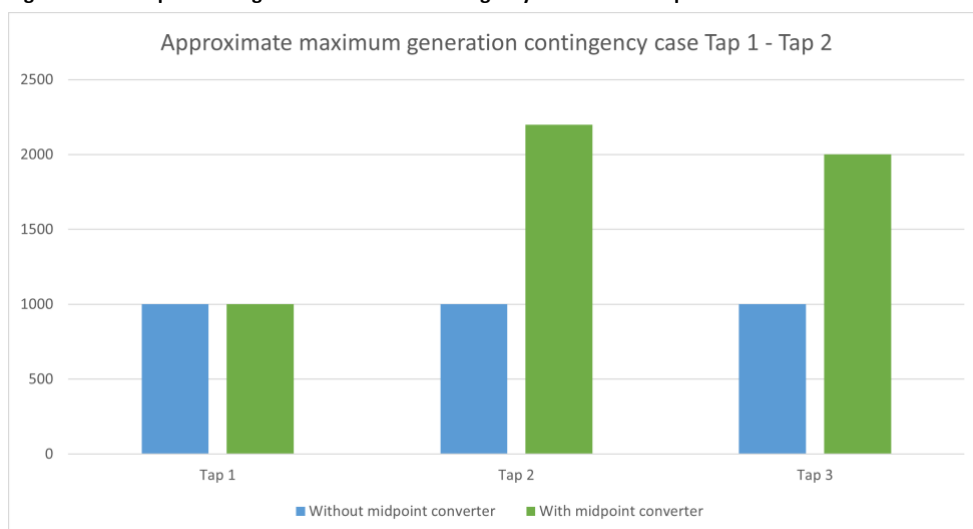


Figure 4-17: Comparison of generation levels – contingency case Tap 1 – Tap 2

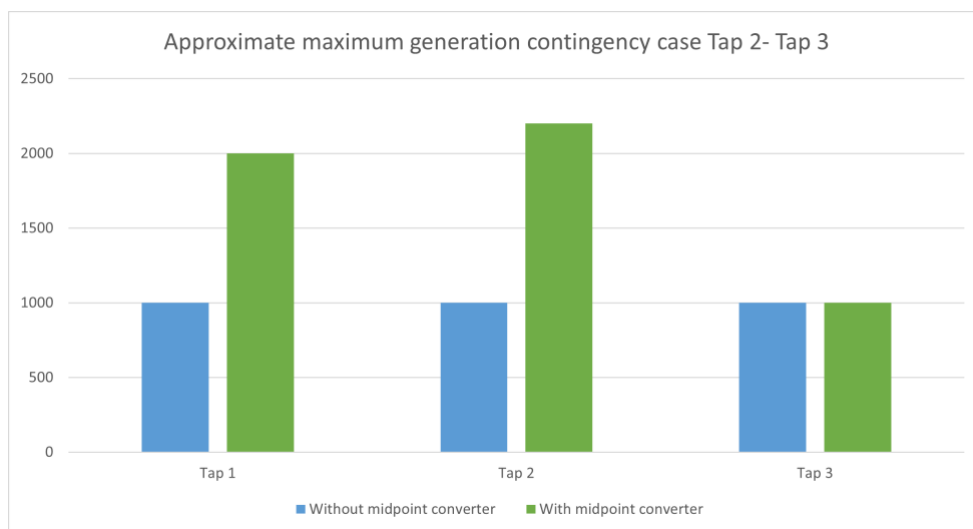


Figure 4-18: Comparison of generation levels – contingency case Tap 2 – Tap 3

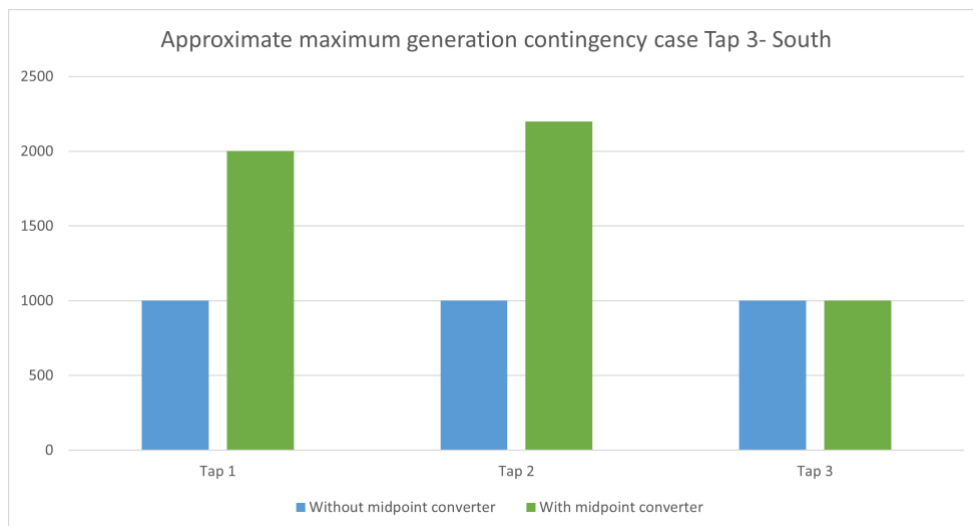


Figure 4-19: Comparison of generation levels – contingency case Tap 3 – South

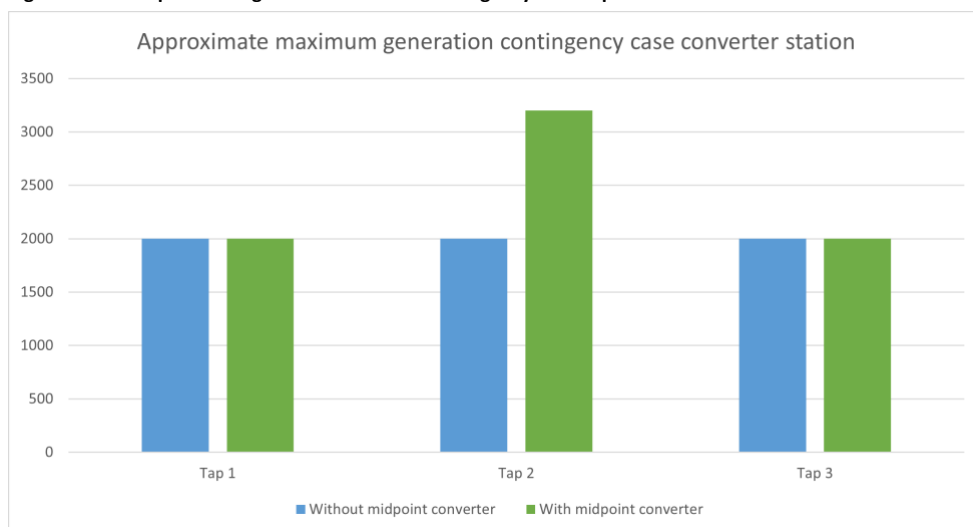


Figure 4-20: Comparison of generation levels – contingency case converter station

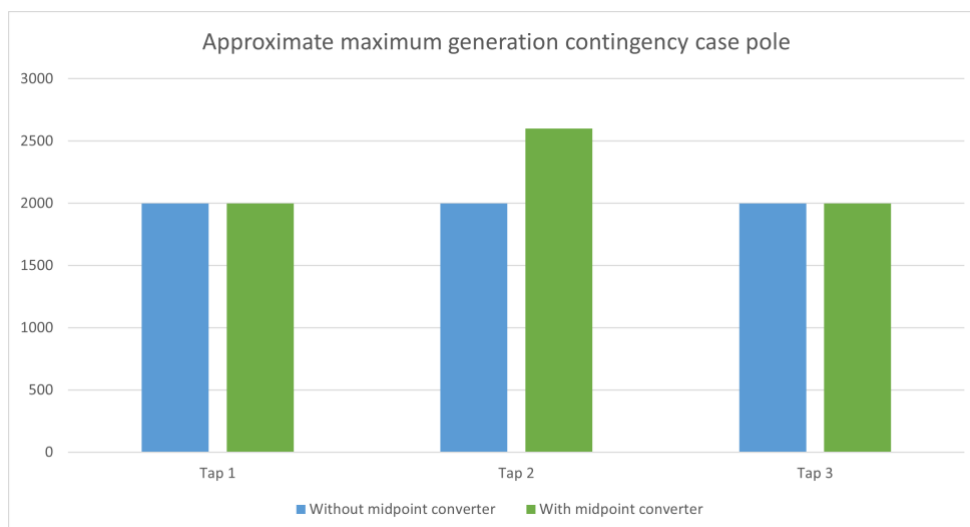


Figure 4-21: Comparison of generation levels – contingency case converter pole

4.6.6 Result discussion

The results indicate that a third midpoint converter station can support the transmission corridor by improving load levels, operational flexibility, and robustness against various system disturbances. The base-case hybrid AC DC transmission concept shows an inherent drawback compared to traditional double-circuit AC transmission, as there is no natural connection between the DC link and the taps on the parallel AC circuit. On a classical double-circuit AC transmission corridor, both parallel circuits would be tapped and have direct connection to any load or generation attached to the corridor. As such, the hybrid solution comes with a natural disadvantage in terms of connection load or generation on the corridor itself, considering that only the capacity of the AC circuit can be directly utilized to exchange power with the overlying system. The midpoint converter can allow the hybrid solution to utilize both circuits more efficiently under various system conditions.

The simulated results indicate that the additional midpoint converter station introduces flexibility for the hybrid AC DC transmission concept and may increase the total load and/or generation which may be connected along the transmission corridor. Furthermore, the midpoint converter station introduces more controllability of the power flow over the transmission corridor and from any load or generation attached to the AC circuit taps. However, the benefits and necessity of a flexible transmission corridor depend highly on the system conditions and require case-specific information. Under the assumption that all segments of the AC circuit are loaded to the maximum, the added midpoint converter station will only improve the magnitude of consumption and generation which can be attached at the exact location of the additional converter station. Otherwise, the transmission corridor remains limited by the transfer capacity of the AC circuits, and the DC link cannot increase the power transfer over the AC circuit.

The midpoint converter station provides flexibility and robustness during disturbances (N-1 operation) of significant components on the transmission corridor. The simulated system assumes a maximum transfer capacity between

North and South of approximately 2 GW, which naturally becomes an integral part of system infrastructure, especially when load and generation are connected to the AC circuit taps. Adding an additional converter station allows a significantly higher power exchange from the AC circuit taps to the overlying system for most N-1 scenarios compared to the base-case without midpoint converter station. This means that infrastructure attached to the transmission corridor will likely find more robust connections to the overlying system and thus have more capabilities in supporting the network during failure of components of the transmission corridor. Not only can the third converter station itself support the network during challenging scenarios but also improve how components attached to the transmission corridor can remain in operation and contribute to a healthier system.

It is also important to highlight the disadvantages of the midpoint converter station. Most disadvantages are not directly visible from the load flow analysis performed as part of this report. Apart from the massive cost increase (see Section 3) by constructing and maintaining a third converter station, which already limits the incentive of such an installation, it also introduces challenges in terms of system operation. The first one being the added complexity in system control and eventual control interactions, which are important aspects that should be studied in detail during the concept study phase of a real connection. As opposed to traditional AC circuits, DC links must be precisely controlled to maintain safe and reliable operation. The third converter station forms a much more complex DC system with three terminals, all of which must operate in symbiosis and not create system instabilities. The analysis performed in this section assumes that the system remains in a steady state condition and does not consider the transition from normal operation to disturbance ride-through and the consequential N-1 operation. Such aspects are very important to study and may be investigated on case-specific basis when detailed information regarding system conditions and equipment is available.

Furthermore, power system disturbances are largely probabilistic events which will eventually occur. The added complexity of the transmission corridor by introducing a third converter station inevitably creates a higher probability of a single component failure on the corridor. The benefit of the third converter station is that the HVDC link can remain in operation if one terminal is disconnected. Even if this may not always improve the net power transfer capabilities from North to South, it will allow the HVDC link to continue assisting the system with important support functions such as voltage control and fault current control, which should also be considered as a potential benefit for the overall transmission network.

Another important consideration is that the presented configuration assumes that the loads can be fed bidirectionally from both the North and South transmission corridors end simultaneously. This can be achieved either by providing direct infeed from each corridor end, or by utilizing the DC link to control parts of the power flow via the DC circuit and back from the opposite transmission corridor end. If flexible bidirectional power infeed and/or absorption is not possible, the system benefits may be further reduced.

The results indicate that an outage of any segment of the AC circuit significantly reduces the load that can be connected at the corridor taps considering potential transfer capacity constraints on the AC circuit. In such a case, load shedding schemes may be necessary to ensure that the load is limited during a contingency such that the remaining segments of the AC circuit do not trip as a cascading event due to exceeding thermal or stability-related constraints. Outage of a converter pole does not significantly impact the load connected to the transmission corridor, under the assumption that power can be generated on either side of the transmission corridor and that the converter pole does not hold a critical role in ensuring local system stability.

The analysis assumes that no load or generation is attached at any of the other taps on the AC circuit. The addition of generation or consumption of power at those locations would present many possible operating scenarios and different results for contingency analysis. Considering that this analysis would be highly case-specific, it is not included as part of this study.

5 EMT Simulations

The electromagnetic transient (EMT) performance of a 460 km, 400 kV transmission corridor is strongly influenced by line length, distributed parameters, terminal equipment, and the dynamic characteristics of connected plant. For both the conventional HVAC and the hybrid AC–DC alternatives, including the hybrid AC MTDC option, acceptable performance is not determined by the line alone, but by the overall scheme design, including switching devices, surge protection, reactive compensation, and control systems.

A fair comparison must, therefore, recognize that a practical 400 kV HVAC transmission development would not normally be implemented as an uncompensated bare line. Rather, it would typically include:

- shunt reactors to control charging current and light-load overvoltages,
- series capacitors to improve transmission capacity,
- surge arresters at critical substations and possibly at line/cable transition points,
- controlled switching for line and reactor energization, and
- dynamic support devices such as STATCOMs or SVCs where required by voltage control or angle stability considerations.

Similarly, the hybrid AC–DC options, including the hybrid AC MTDC option, benefits from active converter control, but also introduces converter-originated transients, control interactions, and DC-side fault behavior that are not present in a purely HVAC scheme.

5.1 EMT BEHAVIOUR OF A 400 KV HVAC TRANSMISSION SCHEME

A 460 km overhead HVAC line system connecting load substations along the length of the corridor, remains a distributed-parameter system in which travelling waves, reflection phenomena, and network resonance are important. However, in a practical transmission design, these effects are moderated by terminal equipment and operational measures.

The principal EMT characteristics of the HVAC option are expected to arise from:

- line energization and re-energization,
- fault inception and clearing,
- load rejection,
- shunt reactor switching,
- interaction between the long line and surrounding network impedance, and
- possible control interaction with dynamic reactive support devices.

The uncompensated line would exhibit strong charging-current-related behavior, but this is not representative of an actual implementable design. A well-designed AC system will have necessary compensation included, addressing the voltage profile, transient overvoltage magnitudes, and post-switching oscillations.

Where angle stability, voltage stability, or post-disturbance voltage recovery become challenging, the HVAC scheme may be reinforced using STATCOMs or other FACTS devices. From an EMT perspective, this changes system behavior in the following ways:

1. Dynamic reactive support can improve post-fault voltage recovery.
2. Low-frequency voltage oscillations can be damped.
3. Line energization and load rejection voltage excursions can be moderated.
4. System stiffness / strength at the terminal bus can be increased.

This does not mean that the HVAC system becomes equivalent to an HVDC scheme in terms of controllability, but it does mean that a fair comparison must account for the fact that the AC option can be materially strengthened by established FACTS technology. In particular, weak-grid behavior and angle-stability-related voltage swings should not be attributed solely to the line itself if a realistic AC design would include dynamic support.

At the same time, STATCOMs and SVCs introduce their own control dynamics and harmonic characteristics, and their performance depends on tuning, network strength, and coordination with other plant controllers.

Even with proper design and mitigation measures implemented, the HVAC scheme retains some adverse characteristics, inherent to long AC transmission, some of which are mentioned below.

- Distributed charging behavior remains present, even if reduced.
- Synchronizing and angular interactions remain part of the power transfer mechanism.
- Switching and fault events still generate multi-frequency oscillatory responses.
- Line remains more sensitive to network impedance and compensation tuning than a DC link.

Thus, the comparison should not suggest that compensation removes all HVAC challenges, but rather that it can reduce them to acceptable and often operationally manageable levels, if these challenges are indeed noticed during engineering studies for a specific transmission project.

5.2 EMT BEHAVIOUR OF THE HYBRID AC–DC ALTERNATIVES

The hybrid AC DC transmission option retains one AC circuit and converts the other circuit for DC use. The resulting corridor therefore combines conventional AC travelling-wave and switching behavior on the retained HVAC circuit,

together with converter-driven dynamics on the DC path. The hybrid AC DC solution is assumed to be in parallel to the AC system connecting several 400 kV AC substations along the length of the corridor. This AC system is assumed to be connecting loads, inverter-based resources and other customers, and is required to be operationally stable, robust and ensure necessary system security.

The hybrid AC MTDC option also retains one AC circuit and converts the other circuit for DC use. The resulting corridor therefore combines conventional AC travelling-wave and switching behavior on the retained HVAC circuit, together with converter-driven dynamics on the DC path. The parallel 400 kV AC transmission system, connecting various loads and sources, is now also assumed to feature an HVDC terminal, linking with the hybrid AC DC corridor, forming a multi-terminal HVDC system.

The main EMT features of the hybrid options are expected to arise from converter energization and blocking/deblocking, DC line charging and control ramping, pole-to-ground or pole-to-pole faults, AC-side commutation or control interactions and AC/DC coupling during disturbances.

The hybrid options, therefore, do not eliminate EMT complexity. It shifts much of the dominant transient behavior from passive network resonance toward converter-controlled dynamics and DC fault response. With both the hybrid options, the overall system response will always be a function of the various controller and protection characteristics and can be configured to benefit or disadvantage the overall system performance.

As discussed earlier, it is not possible to provide any definitive simulation results that will enforce or support the hypothesis that a multi-terminal HVDC system is beneficial to system performance, in generalized terms. Unless the HVDC option, with or without a third HVDC terminal, is designed in coordination with the overall transmission grid system requirements pertaining to stability and security and transmission capacity criteria, there is no valid acceptance criteria against which the hypothesis can be tested.

Advantages of the Hybrid Options in EMT Terms

If correctly designed and implemented, HVDC offers the following EMT related advantages:

1. DC power flow is not constrained by rotor angle stability.
2. Fast converter controls can support voltage and power recovery.
3. Active modulation and control can damp certain sub-synchronous network oscillations.

Under some disturbances, particularly those associated with AC power-angle swings or large reactive excursions, the hybrid option, with or without the third HVDC terminal may, therefore, show a more controlled recovery than the double-circuit AC line.

However, the extent of this advantage depends on the converter technology, control strategy, terminal strength, and grounding arrangement. It should not be assumed to be universally superior under all transient conditions.

EMT Complexity Introduced by the multi-terminal HVDC Option

The introduction of a multi-terminal HVDC (MTDC) scheme significantly increases the complexity of electromagnetic transient (EMT) studies compared to conventional point-to-point HVDC systems. In an MTDC network, multiple converter stations are electrically coupled through a common DC system, resulting in strong dynamic interactions between terminals that must be resolved on sub-millisecond timescales. Unlike two-terminal schemes, where control roles, like DC voltage control and active power control are clearly defined, MTDC systems require coordinated multi-terminal control strategies, typically involving DC voltage droop control, hierarchical supervisory control, and dynamic power sharing between converters. This introduces additional sensitivity to project specific control tuning, particularly under disturbances such as DC faults, AC faults, or large power setpoint changes. Various dimensions of this complexity are described below.

1. From an EMT modelling perspective, each converter must be represented with sufficient fidelity to capture internal dynamics, control loops, and interaction with both AC and DC systems. In MTDC configurations, these models cannot be studied in isolation, because DC voltage dynamics, circulating currents, and control actions at one terminal propagate instantaneously across the DC network, influencing the behavior of all other terminals. This creates challenges in achieving numerical stability and convergence, particularly in large-scale EMT simulations with multiple converters and long DC cables or overhead lines.
2. Fault behavior represents a critical area of increased complexity. In MTDC systems, DC faults lead to rapid voltage collapse and steep current rise across all terminals, requiring accurate modelling of protection schemes, converter blocking strategies, and, where applicable, DC circuit breakers. The coordination of protection across multiple terminals is non-trivial, as fault detection and isolation must occur selectively while maintaining system integrity. This necessitates detailed EMT representation of protection logic, breaker operation times, and post-fault recovery sequences.
3. The interaction between AC system strength and converter control becomes more pronounced in MTDC systems. Variations in short circuit ratio (SCR) at different terminals can lead to uneven dynamic responses, control interactions, and potential oscillatory behavior, particularly when multiple converters attempt to regulate DC voltage or provide voltage support simultaneously. This is especially relevant in islanded networks where weak grid conditions are prevalent.
4. MTDC systems introduce additional complexity in defining credible study cases. EMT studies must consider a broader range of operating scenarios,

including multi-terminal power flow permutations, converter outages, DC line contingencies, and asymmetric operating conditions, all of which can significantly affect system dynamics. As a result, the study effort, model validation requirements, and computational burden are substantially higher than for point-to-point HVDC systems.

In summary, the MTDC option introduces a step change in EMT study complexity due to multi-terminal control interactions, fast DC fault dynamics, protection coordination requirements, and increased scenario space, all of which must be carefully addressed to ensure robust and reliable system performance. For these reasons, performing detailed EMT simulations without project specific, user defined, OEM supplied models at this early concept phase is not feasible.

5.3 DEMONSTRATION SIMULATIONS

EMT simulations are part of the scope of work of this project. At a conceptual development stage, transmission system requirements and project specific HVDC designs that can be used as basis for a definitive EMT study are not available. As these vital simulation study components are not available, a demonstration simulation is performed to illustrate a generic system response of different transmission system technologies and topologies. For the purpose of distinction, the pure AC option transient response is compared to the hybrid AC DC system response. Multi-terminal HVDC option is not investigated at this stage, as the control and protection philosophy is extremely niche and project specific.

As a starting point, it is necessary to define the boundary parameters for the simulation scenarios being considered in this report, even in the context of the simulations being for demonstration purpose only. The parameters are supposed to represent a typical 400 kV grid, with a typical load flow requirement across the transmission system. HVDC systems are presently constrained to a certain extent to 2 GVA per bi-pole converter system, as requirements and industry standards have converged on this capacity.

The AC solution is considered to be designed to a certain extent, so that the transfer capacity of the AC circuit should be able to match that of alternative DC circuit. The transmission line AC circuit of the hybrid corridor is, therefore, considered to have 50% series capacitor compensation installed on either end of the line. The setup is shown in Figure 5-1.

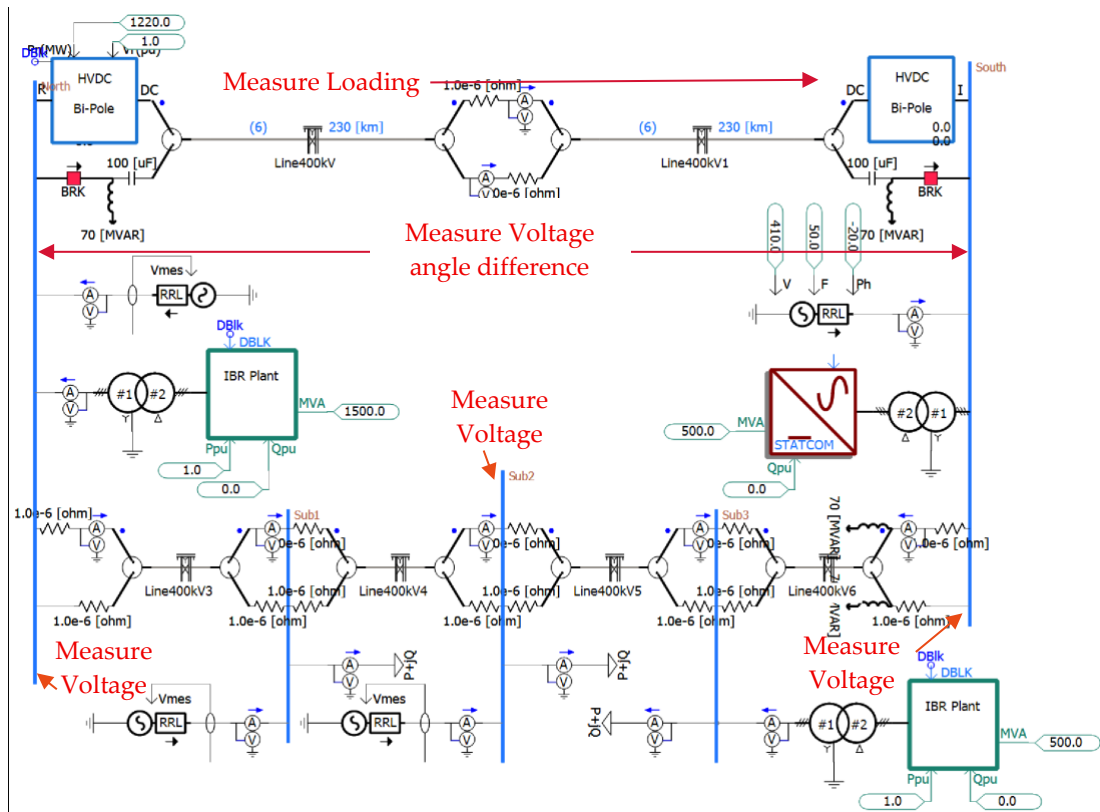


Figure 5-1: 460 km, 400 kV AC transmission corridor concept in PSCAD

Any MTDC simulation model is too design-specific to herald any generalized simulation results that could yield meaningful insights in the context of the evaluation performed in this report. MTDC systems need specific controller settings, based on actual grid requirements, which will then define the outcome.

Instead of simulating general disturbance events in a general system model, using a specifically configured MTDC system, the EMT simulation results outlined in this report attempt to show that the AC-only and HVDC hybrid solution will both perform satisfactorily, if designed correctly. The outcomes can be extrapolated to also infer similar transient performance-related capability for MTDC converters.

5.3.1 Fault Response

For AC faults, the HVAC scheme exhibits familiar transient behavior associated with fault current contribution, breaker interruption, transient recovery voltage (TRV), and post-fault voltage recovery. These phenomena are well understood and can be mitigated using established equipment design and protection practice. Where the AC system is reinforced by STATCOM or FACTS support, the post-fault voltage recovery can be materially improved, particularly for remote faults or weak receiving-end conditions.

The hybrid option may reduce some electromechanical coupling and can provide rapid power modulation, but this would be accompanied by the need to manage DC-specific faults, converter blocking logic, and fault-clearing philosophy.

A fair EMT comparison should include several aspects, the first of which is AC fault performance on the retained HVAC network. The results of fault behavior for a double-circuit AC line are shown in Figure 5-2.

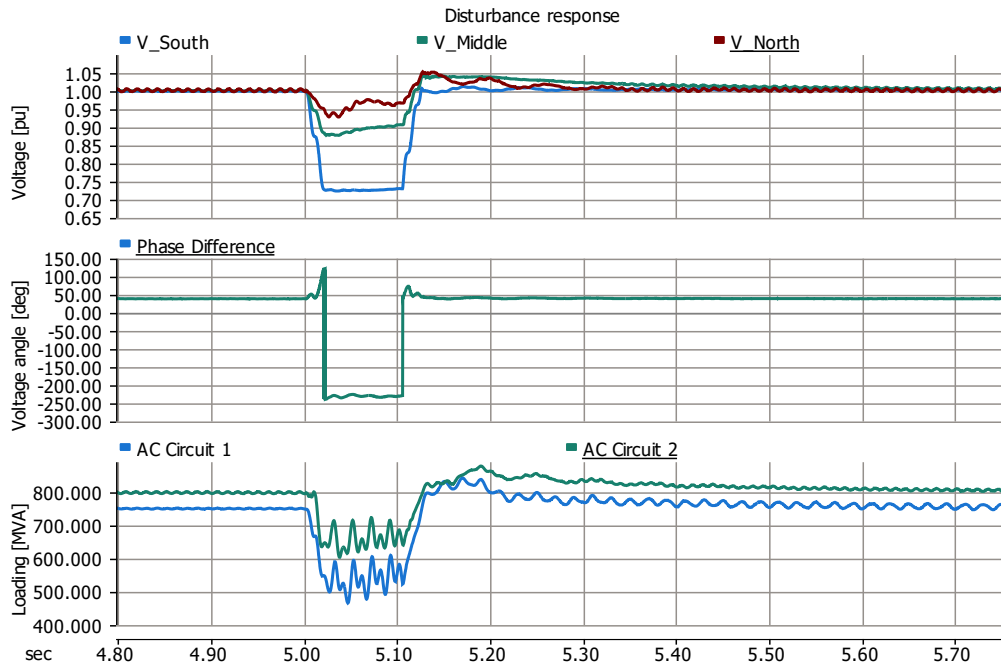


Figure 5-2: Fault response of a double circuit AC line

Another interesting aspect is DC single-pole blocking performance on the converted path. Results of simulation of such an event are shown in Figure 5-3.

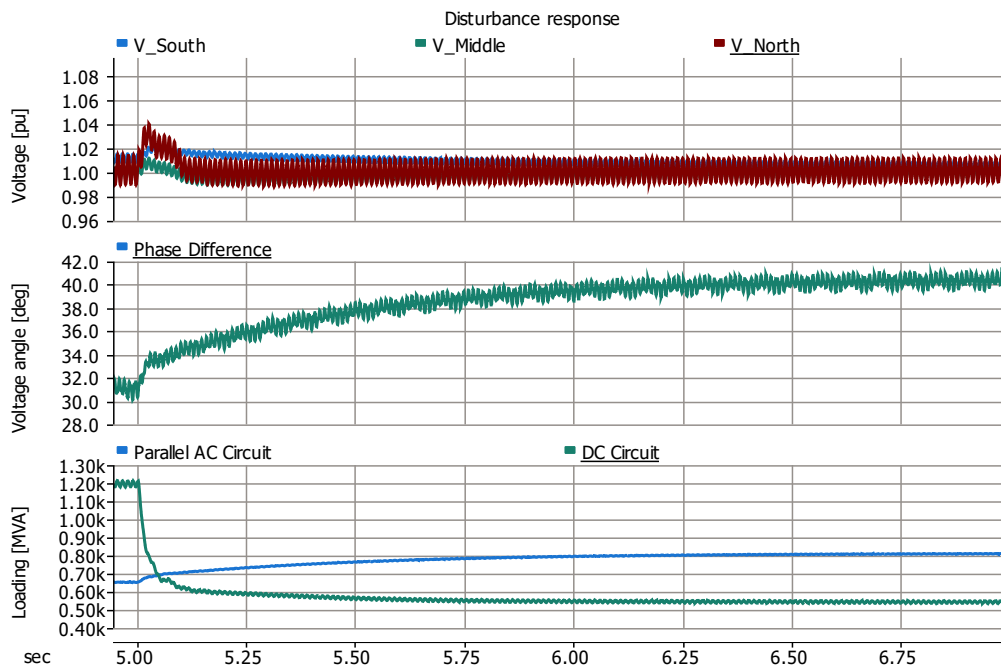


Figure 5-3: Response to single-pole blocking on the DC line

Yet another interesting case is the mixed AC/DC disturbance propagation across the corridor. Simulation results for such an event are shown in Figure 5-4.

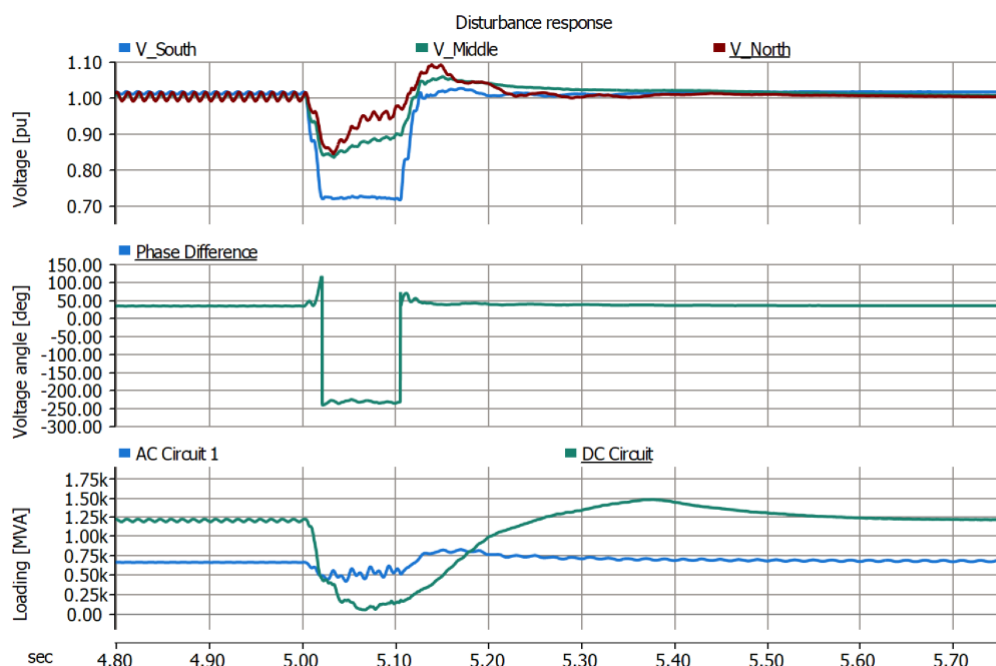


Figure 5-4: Response to mixed disturbance propagation

As there are no acceptance criteria for the disturbance response performance in the demonstration system, relating to loading limits, power quality, etc., the simulations only serve to illustrate that the system is able to contend with typical fault related disturbances, whether in double-circuit AC or in hybrid AC-DC configuration.

5.3.2 Oscillatory Behavior and Damping

The double-circuit AC option is more naturally associated with network oscillatory modes, particularly on long transmission paths. However, the presence of FACTS support can improve damping and voltage stability, and in some cases, this may be sufficient to satisfy operational requirements without corridor conversion.

The hybrid AC DC option offers additional controllability and may provide superior damping in some operating conditions, but this depends on several conditions being met, most importantly detailed controller tuning after developing a thorough understanding of the system and requirements.

5.3.3 AC line tripping

The uncompensated HVAC case can show significant temporary overloading after a line tripping. However, in a realistic design shunt reactors absorb part of the reactive surplus and STATCOM and other FACTS devices can support and dynamically regulate voltage. The second circuit on the AC line will be able to assist in transferring some of the power from the tripped AC circuit. In the hybrid configuration, the HVDC system will not compensate for the loss of the AC connection, parallel to the HVDC interconnector, by increasing transfer capacity. This implies that the excess loading will be forced through the parallel

interconnector system servicing other loads. Simulation results for such scenarios are depicted in Figure 5-5 and Figure 5-6.

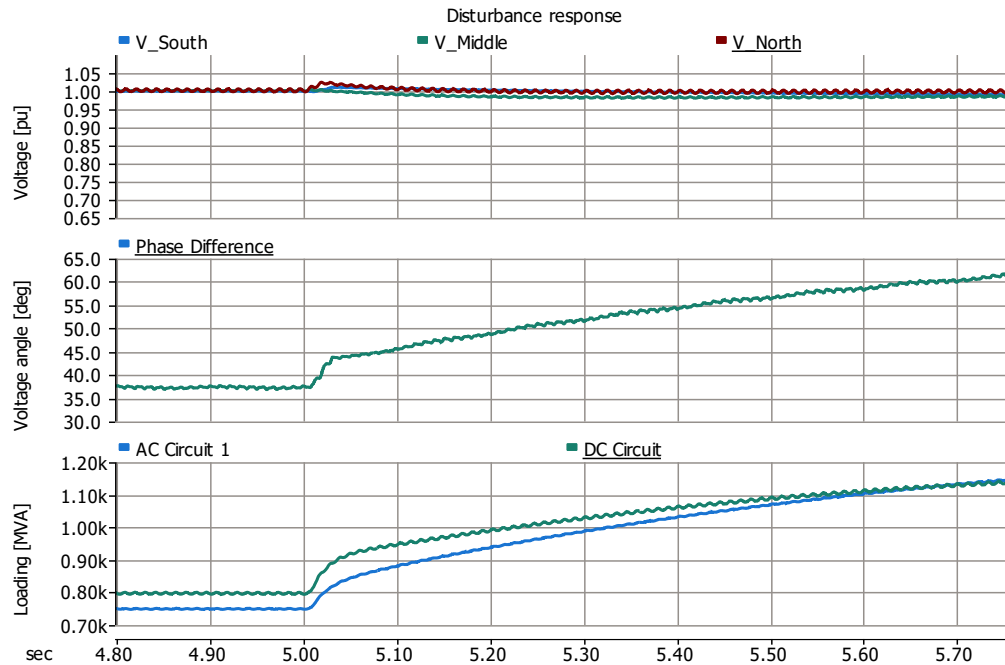


Figure 5-5: Response to line tripping in double-circuit AC transmission

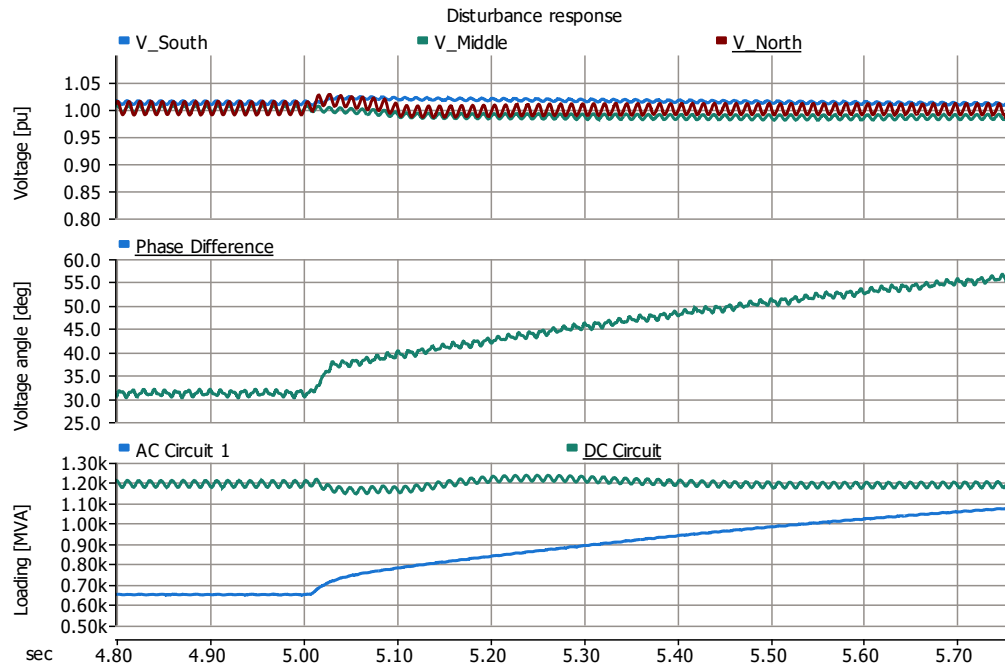


Figure 5-6: Response to line tripping in hybrid AC DC transmission

The hybrid AC DC option may still benefit from converter-based rapid power reduction, but the comparison should recognize that the AC scheme can also be designed to manage this duty effectively.

The relevant study question is, therefore, not whether the hybrid scheme has lower overvoltage than an unmitigated AC line, but whether it delivers materially lower residual overvoltage than a compensated and dynamically supported AC scheme, and whether that difference is significant in relation to insulation coordination and equipment specification.

5.3.4 Transient Complexity and Protection Burden

The double-circuit AC scheme relies on mature and widely deployed protection principles for overhead lines, reactors, and associated substations. Its transient behavior is comparatively well established and often easier to interpret in conventional utility design practice.

The hybrid AC DC option introduces a broader protection and control envelope, including:

- converter protection,
- DC fault discrimination,
- AC/DC interaction management, and
- grounding-return assessment.

Therefore, even if some transient quantities are lower in the hybrid option, this does not automatically imply a simpler or lower-risk overall EMT design.

Adding a third converter terminal to the central busbar of the grid will not change the overall findings in the transient domain assessment, as the conclusion from the simulations presented above remain true: A well-designed double-circuit AC solution will have an acceptable disturbance response performance, similar to when a hybrid AC MTDC option is considered. Regardless of the topology choice between double-circuit AC, hybrid AC, or hybrid AC MTDC, the technology and its implementation must be defined by the actual grid requirements and the solution must be then designed to meet the specified acceptance criteria.

5.4 CONCLUSION

The comparative EMT and steady-state assessment indicates that both, a fully engineered HVAC solution and a hybrid AC–DC configuration can be designed to meet technical performance requirements for a 460 km, 400 kV transmission corridor. When equipped with appropriate mitigation measures, such as shunt compensation, surge arresters, controlled switching, and dynamic reactive support, the HVAC option can achieve acceptable performance across a wide range of operating conditions, at a reasonable OPEX and CAPEX, compared to a solution including HVDC.

However, the hybrid AC DC configuration offers a fundamentally different operating paradigm, in which a portion of the power transfer is decoupled from synchronous AC network constraints and is instead governed by fast, controllable power electronic interfaces. This distinction becomes increasingly relevant in

specific transmission scenarios where conventional reinforcement measures become complex, space-constrained, or economically inefficient.

Accordingly, the hybrid AC MTDC solution should not be viewed as a universal replacement for double-circuit HVAC solution, but rather as a targeted enhancement strategy that becomes advantageous when particular system drivers dominate.

The hybrid AC DC configuration becomes a strong candidate when one or more of the following technical conditions apply.

5.4.1 Corridor Capacity Limitation Without Additional Right-of-Way

Where the existing double-circuit AC corridor is approaching its transfer limit and expansion via new lines is constrained due to environmental, permitting, or spatial limitations. The hybrid AC DC option could allow a step increase in transferable power without requiring additional towers or corridors and with improved utilization of existing conductors. In such cases, the hybrid AC DC solution effectively converts stability-limited capacity into thermally limited capacity for part of the corridor.

5.4.2 Long-Distance Transmission with Marginal Stability Margins

For transmission distances in the order of 300–500 km and beyond, HVAC transfer is inherently influenced by angular stability and network impedance, even when supported by series compensation and dynamic reactive devices.

Where stability margins become restrictive or require extensive and complex compensation schemes, the hybrid AC DC option provides a partially decoupled power transfer path, reducing reliance on synchronizing torque and network angle stability, and enabling more predictable power transfer under varying system conditions.

5.4.3 Weak Grid Connections and Low Short-Circuit Strength

In systems characterized by low short-circuit ratios (SCR), high penetration of inverter-based resources (IBRs), or remote generation clusters, the hybrid AC DC option can provide controlled power injection independent of local voltage phase angle. Fast dynamic support through converter control and improved robustness against voltage instability are benefits afforded by the hybrid AC DC option.

While double-circuit HVAC solutions can be reinforced using STATCOMs or SVCs, the hybrid AC DC configuration integrates controllability directly into the transmission path, which may simplify overall system behavior in weak-grid conditions.

5.4.4 Highly variable load flows

For corridors evacuating large volumes of wind or solar generation, rapid changes in power output can stress HVAC systems through voltage and angle dynamics. Coordination between plant controllers and network support devices becomes

increasingly complex. The hybrid AC DC option offers fast and precise power modulation, improved damping of system oscillations, and reduced sensitivity to generation variability. This is particularly relevant where multiple large plants are aggregated onto a common transmission path.

5.4.5 Controlled power exchange requirement

Where the transmission corridor connects electrically weakly coupled regions, or systems with different dynamic characteristics, the hybrid AC DC option enables controlled power exchange independent of phase angle.

5.4.6 Operational Implications Supporting Hybrid AC DC Deployment

From an EMT perspective, the hybrid AC DC configuration can provide several advantages. However, these advantages are most meaningful when evaluated against a realistically compensated double-circuit HVAC baseline. The hybrid AC DC option should, therefore, be justified not by absolute reduction in transient magnitudes alone, but also by the system need for improved controllability under stressed system conditions, reduced reliance on multiple discrete mitigation devices, and enhanced predictability of system response.

6 Conclusions

The concept of embedding HVDC in an AC power system is not new. It is, however, a niche area which should be chosen after exhausting all other technical solutions at the disposal of system planners, because it is financially expensive in addition to introducing several technical challenges. The increasing penetration of variable generation and loads in the power system are generating several circumstances where such solutions might be indispensable.

The adoption of such solutions should be gradual and phased. This report introduces one such scheme where one circuit in a double-circuit AC transmission line is converted to DC. Whatever, the driver for such a conversion, the system transient and steady-state behaviour should be similar to or better than the double-circuit AC option.

Additional load and generation along the corridor of such a hybrid line would require connection. As these connections are predominantly AC, these new connections will logically connect to the AC circuit. This is restrictive compared to the possibility of connecting to either or both circuits in a double-circuit AC line. The project proposes a strategy where the AC and DC circuits are connected at an appropriate location in the corridor enabling more possibilities of connecting new generation and loads. The connection is only possible through an AC DC converter and transforms the two-terminal DC circuit in the hybrid line into a multiterminal HVDC system where three AC DC converters connect and exchange energy with the AC circuit.

As is clear from the discussion in the report, this solution is technically complex and expensive. However, it is the only solution to enhance connectivity in a hybrid line. This project explored several technical aspects of such a solution and concluded that it offers more controllability under normal operation and contingencies. The work included specifying various components and ratings for such a solution, estimating costs, and performing simulation studies to check the adequacy of proposed solution.

Future work could include more thorough specification work, simulation with more specific and detailed grid scenarios, and studies of impact of such solutions on the wider power system.

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Hybrid AC MTCD Transmission System

The increasing stress on electricity transmission networks posed by increasing loads and renewable generation needs innovative solutions to cover for the lagging investments in grid expansion. One such solution is the introduction of embedded HVDC, first in the form of a point-to-point connection sharing the transmission corridor with a high-voltage AC circuit and later converted to a multiterminal DC system. Such solutions, though technically complex and expensive, will become indispensable in certain application environments which are bound to become more prevalent due to the increasing volatility of demand and supply.

This project explores the evolution and basic design of such an idea. The project scope included basic specifications, preliminary cost estimates, and simulations. The outcomes reveal that it is possible to create reliable hybrid AC DC systems which can match the performance of AC solutions under traditional scenarios. Such hybridization is the only way to tackle certain grid challenges where traditional AC solutions do not work.

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