OFFSHORE COORDINATION

Holistic Approach to Offshore Transmission Planning in Great Britain

National Grid ESO

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Objective:

Analysis of technical aspects of the coordinated approach to offshore transmission grid development in Great Britain. Overview of technology readiness, technical barriers to integration, proposals to overcome barriers, development of conceptual network designs, power system analysis and unit costs collection.

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EXECUTIVE SUMMARY

To date, each transmission connected offshore wind project within Great Britain's ('GB') offshore waters has a separate connection and there is limited opportunity (if any) for shared use of offshore transmission assets. Under current arrangements, each offshore wind farm development will contribute to overall carbon emission reduction targets in accordance with timescales that are defined on a project specific basis.

The United Kingdom ('UK') Government has an ambition to achieve 40 GW by 2030 of installed offshore wind capacity, potentially rising to at least 75 GW by 2050. Achievement of these 2030 and 2050 targets is expected to require a step change in development approach in terms of both volume and pace. The electricity industry is set to invest several £10s billions in offshore wind and associated connection infrastructure over the coming ~30 years (a cost which will ultimately be borne by GB consumers)[1].

Without a change of approach, the required increase in volume and pace of network development is expected to lead to issues including:

- lack of suitable cable landing points onshore;
- adverse impacts on transmission system stability;
- project delays due to the unavailability of equipment and resources due to stresses on the supply chain, and
- failure to deliver economies that would be expected with a large-scale increase in development volumes.

Each of these issues in the current approach could lead to increases to the overall cost of transmission system extensions and to the risk that connections for offshore wind projects will not be delivered on a timely basis.

Eight conceptual network design building block options for offshore connections were identified of which:

- Four use High Voltage Alternating Current ('HVAC') technologies, and
- Four use High Voltage Direct Current ('HVDC') technologies (explanations to these and other technical terms across the report can be found in Appendix J)

that have been used in Europe and Asia.

This report illustrates a method for identifying and assessing offshore network designs which is integrated with the onshore processes set out in the Electricity System Operator's ('ESO') Future Energy Scenarios ('FES'), Electricity Ten Year Statement ('ETYS') and Network Options Assessment ('NOA') publications.

For the purposes of this assessment, the key features of an integrated offshore network design which were assumed:

- offshore transmission assets can be shared between offshore projects;
- design can be optimised across projects, taking account of the required "end state" (i.e. overall target levels of offshore generation connected), rather than a project by project approach. This can limit the extent of offshore and onshore assets required;
- offshore network design must meet current SQSS requirements and also consider strategically how the connection can provide support to the wider transmission system. This approach can be used to minimise the consequential impact to the onshore system;
- the overall design may be modularised and implemented in a stepwise manner using standardised components, with that build-up aligning to the capacity required by offshore projects, and
- design efficiencies from a range of technologies available were taken into account and where possible, used to restrict development of onshore assets to areas where amenity impacts can be better managed.

We have considered if there would be benefits from using an 'integrated' approach for offshore transmission development that is more similar to the approach used onshore. An integrated offshore network design approach could enable:

- shared use of offshore transmission assets between connections (e.g. wind, interconnectors);
- incremental development of offshore transmission infrastructure that matches the pace required for offshore wind projects, and
- a more holistic network development to be achieved (e.g. also enabling issues elsewhere on the transmission system to be addressed).

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[1] https://www.auroraer.com/insight/reaching-40gw-offshore-wind/

Our analysis highlights that such integrated offshore transmission solutions could be key to realising the full potential of the offshore wind resource in GB and facilitating offshore wind targets being met. Coordinated development of offshore transmission infrastructure in a more efficient way has the potential of reducing the impact on environment, communities and overall project costs compared to cumulative radial transmission options.

Our integrated designs can be delivered using HVAC and/or HVDC technology solutions that are available today, with demonstrated capability to deliver the required performance levels. As part of this assessment, we have identified how efficiencies beyond these approaches can be realised over time, from a firm foundation of a deliverable and efficient initial integrated design decision. Our initial findings indicate that-

- all integrated offshore designs (irrespective of their detailed design) could drastically reduce offshore cabling that is required to be landed onshore. For example, for the most efficient of the design options assessed up to 60% of the volume of offshore cabling otherwise required by radial designs would not be required to connect the 2030 levels and 2050 levels of offshore wind development. Integrated solutions can by sharing infrastructure within GB reduce the volume of onshore substation and associated connection and consequential onshore reinforcement required, resulting in overall asset reductions.
- reductions in the volume of assets required, would be expected to correspond to a cost saving in the infrastructure costs associated with integrated offshore. It is recognised that with a reduction in numbers, integrated solutions will use in many case higher capacity assets with higher attendant costs and as such cost impacts would be expected to vary across the GB system and the exact balance would need to be confirmed by a cost benefit assessment.
- efficiencies to the supply chain and delivery of integrated offshore could be facilitated by introducing standardisation of integrated offshore designs used, and the modular year-on year construction of the integrated designs, in step with the pace of offshore generation growth in each area.
- benefits to local coastal communities can be achieved by avoiding congestion of projects landing upon the onshore GB transmission system so that the overall scale of infrastructure required is minimised.
- integrated offshore designs distributing their power system voltage, stability and power flow support strategically across the onshore GB transmission system, can support transmission system operation and minimise the level of onshore network reinforcement and ancillary services.

Barriers were identified in the existing legal framework (applicable to electricity transmission), that could limit the delivery of integrated offshore network designs identified. We consider that a wider review of this existing legal framework would be beneficial.

Within existing regulatory arrangements, we recommend that:

- the loss of power infeed limits for offshore generator connections defined in the SQSS are reviewed, and
- parts of the Grid Code that define generator capability and associated compliance process requirements are reviewed to ensure clarity of how they apply to plant connected to an integrated offshore transmission network.

The maturity of technology options (such as larger size cables and convertors) could be improved by use of pilot projects with robust testing. In addition, we recommend that a coordinated process is initiated between energy companies, equipment manufacturers and standard organisations:

- to consider options for the standardisation of offshore network infrastructure topologies;
- for the development of functional specifications for technology options that are currently available;
- to encourage DC Circuit Breaker ('DCCB') deployment to European standards, including onshore trials as appropriate, and
- to seek to deliver relevant European DCCB experience ahead of/in line with GB development timeframes.

This report concludes that integrated offshore network solutions are available which may be deployed from 2025 for offshore transmission system connections. These solutions could deliver benefits in terms of:

- delivery and cost efficiencies that can be achieved by reducing the overall (offshore and onshore) number of assets that is required (compared to current arrangements);
- strategic management of the impacts on coastal communities across multiple projects;

- provision of enhanced levels of support to other parts of the transmission system, across a range of areas and services needed for transmission system operation (e.g. voltage control and stability) and power transfer capacity needs now and in the future;
- lower overall transmission losses, and
- greater overall availability of offshore wind capacity provided via flexible more interconnected transmission system connection designs.

Our initial findings suggest that the required higher capacity and more rapid pace development required for offshore connections to the GB transmission system could be more efficiently achieved by a combination of integrated offshore network topologies. Other conceptual network design topologies (e.g. HVAC approaches) are expected to offer efficient solutions particularly in areas of less pronounced and slower offshore wind technology growth.

The FES Leading the Way ('LW') scenario was used for this assessment, however it is noted that other scenarios with differing distributions of offshore generation and/or different paces of its growth, may drive different outcomes. Based on the expected size and locations of offshore developments (based on FES LW), it is expected that HVDC solutions will be a key technology for offshore transmission developments in the future.

The 2050 benefits of the approach may be visualised in Figure 0-1 below in our illustrative comparison between a counterfactual project-project delivery and an integrated design approach. Our illustrative comparisons show reinforcements which are additional to those identified to progress within the 2020 Network Options Assessment ('NOA'), the 2020 NOA are assumed to proceed in both approaches.

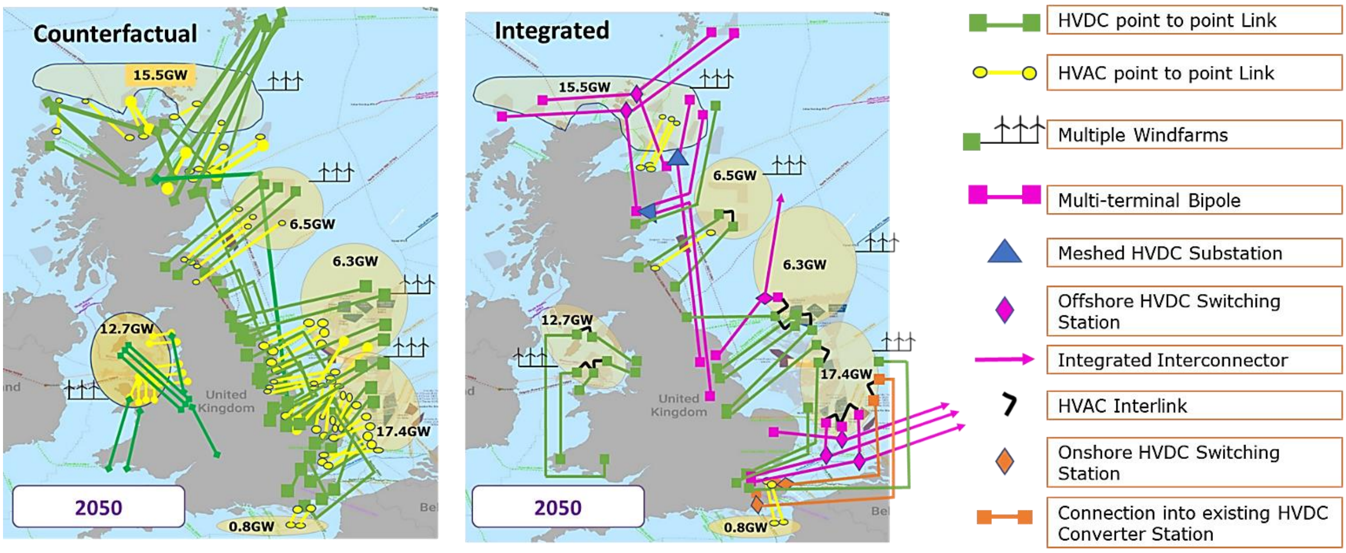

Figure 0-1 Illustrative comparison - Counterfactual and Integrated design approach[2]

[2] In this and other figures presenting conceptual grid designs "HVAC point to point link" implies Design 1 (T1) for the Counterfactual and Design 1A (T1A) for the Integrated. Designs are described in section 4.1.

1. INTRODUCTION

There is a significant drive to increase at an unprecedented scale and volume, the development of offshore wind. The UK Government has legally committed to net-zero greenhouse gas emissions by 2050 within which interim targets exist. Currently there is circa 10 GW of offshore wind installed, with an ambition for growth to 40 GW by 2030 and to 75 GW by 2050.

In line with the UK's commitment for net-zero greenhouse gas emissions by 2050, a step change is expected to the size and numbers of offshore wind farms seeking connection to the transmission system. For this assessment, six regional development zones in GB from the ESO's FES LW scenario were analysed. As part of the LW scenario, both the 2030 and 2050 offshore wind would be met. Figure 1-1 shows on a regional basis. the total installed offshore wind capacities from 2020 to 2050 that were considered as part of the LW scenario.

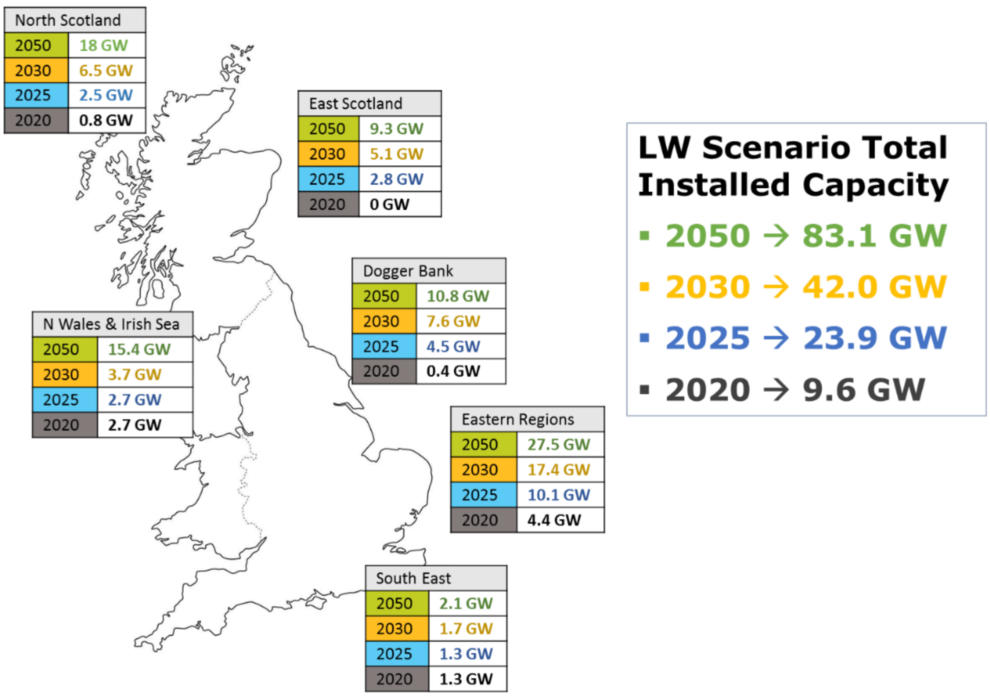

Figure 1-1 LW Scenario growth in Offshore Wind by Offshore Development region

Whilst the existing regime has been successful in delivering some 10 GW of offshore wind to date, a number of technology and related technical challenges with the current approach have begun to emerge which will require addressing in taking forward effective solutions [3]. Issues identified include:

- to date, a project-specific HVAC connection, consisting of one or more radial circuits, has been constructed for each offshore wind farm. Whilst in principle project sharing for subsequent projects may be possible, in practice the opportunity to do so has been limited by the specification of the offshore infrastructure constructed, and its intended operation.
- shared construction of assets from the outset presents regulatory and commercial complexities which may dissuade this approach in many cases.
- new offshore wind farm development areas are becoming progressively larger and further from shore, which approaches the technical limits of conventional HVAC approaches and is resulting in an increasingly focussed development around the nearest coastal communities to the offshore area.
- projects within these new development areas are expected to require connections to the onshore transmission system within similar timescales. As these connections increase in scale within common locations on the edges of the onshore transmission system, this can also require changes to the onshore transmission system (such as consequential reinforcement) to accommodate the

[3] https://www.hvdccentre.com/2020/01/the-national-hvdc-centre-leads-publication-of-technology-report-for-owic/
https://www.hvdccentre.com/wp-content/uploads/2020/06/De-risking-Integrated-Offshore-Networks_v2.0_25June2020.pdf

increasing volumes of offshore projects. These activities can drive additional risk in terms of time, cost and amenity impact.
- as more renewable generation is connected, the GB transmission system security becomes more dependent on the support (in areas such as voltage support, inertia and system stability) that these generators and their associated networks can provide. Our designs respect both security of supply and the technical performance of the connections involved. This ensures that there is no common mode of failure created which can lead to excessive loss of offshore generation (more than 1320 MW offshore) to occur.

The ESO's Offshore Coordination project investigates options for a coordinated network design approach offshore. The impacts that different approaches would have on the volume of new network infrastructure required have been assessed from a:

- transmission system perspective in terms of compliance with existing regulatory framework rules, security of supply, shareability, suitability for future extension and cost and
- stakeholder perspective particularly in terms of amenity and environmental considerations onshore and offshore both during construction and during operational life of the new network infrastructure.

As part of this project, detailed work has been carried out to:

- review different technology options and identify components that are (or are expected to be) available within the offshore wind farm development timescales;
- develop and assess network solution options for connecting new offshore generation to the transmission system;
- identify and assess benefits and considerations that could be provided by more coordinated offshore developments;
- highlight potential barriers to the development of integrated offshore network solutions that were identified;
- consider local coastal community and general amenity impacts associated with different network solution options, and.
- investigate the impact of offshore developments on the onshore transmission system at point of connection and boundaries, identifying at a high level how onshore and offshore networks can work together holistically as part of the whole transmission system.

This report summarises the work carried out to identify and technically assess a range of possible offshore network design options. A separate report summarises the Cost Benefit Analysis ('CBA') work for the design options presented in this report.

This report is structured as follows:

Section 2 describes the key aspects of integrated offshore network design, highlights potential advantages (compared to current radial design approach) that could be offered by integrated design solutions, describes the overall approach, data and assumptions required for this assessment and summarises key areas of feedback from stakeholder engagement received during the project. This section also includes a worked example showing considerations for the East of Scotland region.

Section 3 provides an overview of technology available (existing and potential future) for offshore transmission network development.

Section 4 describes the key features of the conceptual network design topologies identified, the key characteristics of the resultant network design solutions and options for their deployment within the GB transmission system.

Section 5 describes the barriers identified that may limit the development of integrated offshore network solutions and references existing processes that could be used to address these barriers in the future.

Section 6 provides an overview of the technology unit costs that were evaluated and which have informed the development of conceptual network designs.

Section 7 describes the power system analysis undertaken to assess viable network design approaches identified as suitable for use in GB, investigate impacts of new offshore network solution options on the existing (onshore and offshore) transmission system and identify at a high level, more holistic design approaches that could be applied across all parts of the transmission system (onshore and offshore).

2. APPROACH, ASSUMPTIONS AND DATA USED FOR THIS ASSESSMENT

The objective of this section is to provide an overview of the:

- key aspects of integrated offshore network designs;
- potential advantages of integrated offshore network designs in terms of cost, impact on the performance of other parts of the transmission system and impact to communities;
- increased data required for the design and assessment of integrated offshore networks;
- robust methods required to carry out additional analysis for a holistic assessment of integrated offshore network designs, and
- requirements for periodic review of design methods as data and associated assumptions evolve.

2.1. Key Aspects of Integrated Offshore Network Designs

Integrated offshore networks can be designed that connect a number of individual offshore projects (e.g. wind farms, interconnectors) and also take account of wider factors including the:

- level of development zone activity that is expected to need to be connected to that design option over time;
- potential for the design option to be economically extended in line with the expected build-up of offshore wind capacity;
- impact that the offshore network design option has on overall level of transmission system security of supply, and
- options offered to integrate more fully as part of the wider transmission system.

A holistic offshore and onshore framework for planning, assessment and optimisation is required for the development of effective integrated network design options. Figure 2-1 illustrates the stages considered in our structured approach for offshore network assessment.

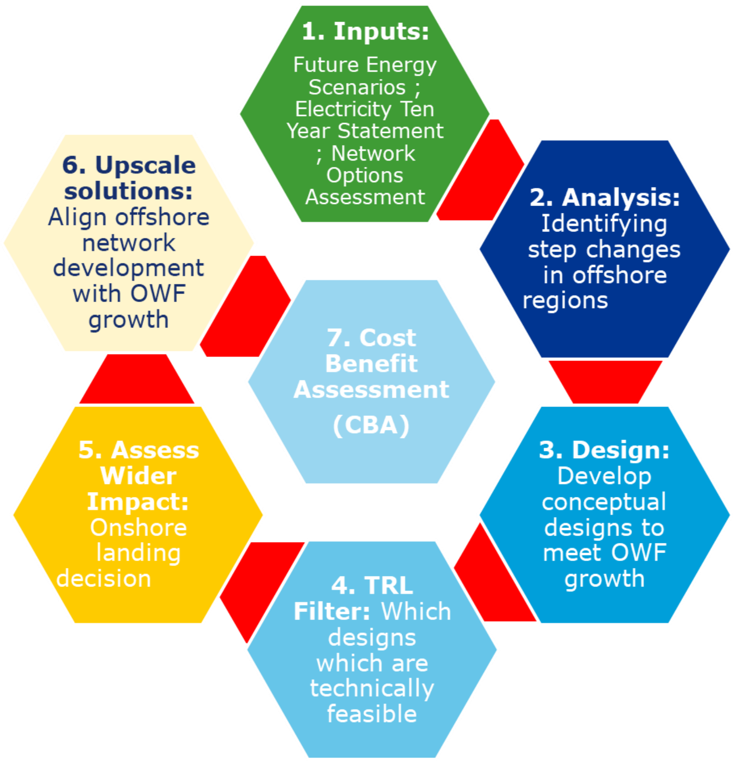

Figure 2-1 Illustration of offshore network options assessment approach

Figure 2-2 illustrates the proposed offshore and onshore network coordination approach, used for implementation of transmission connections to the six regional offshore wind development areas in GB.

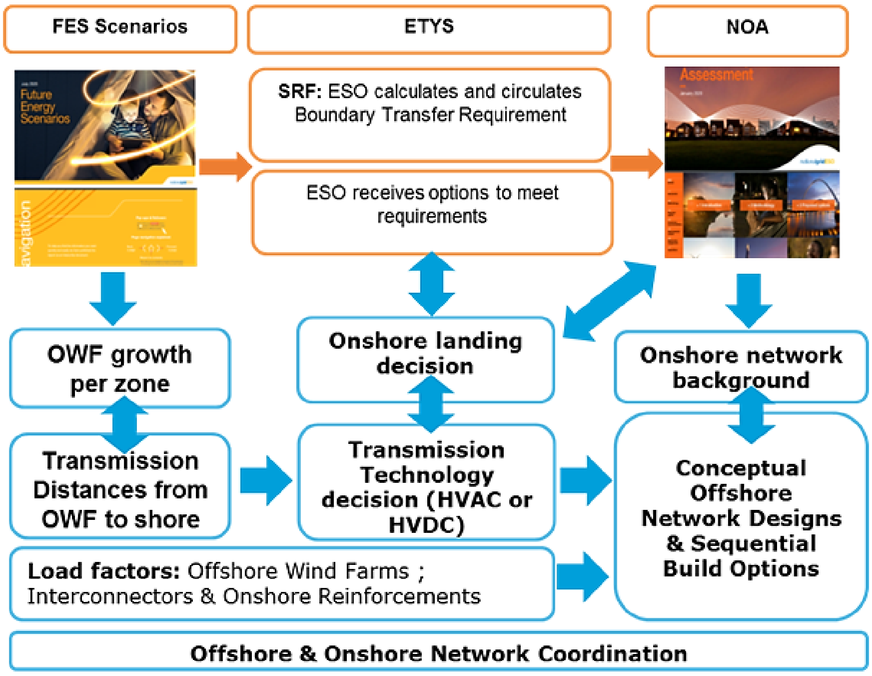

Figure 2-2 Illustration of coordinated offshore network design approach

For the development of efficient and effective integrated offshore networks, designers need equivalent levels of project data to that which is available and used for onshore network design. In particular, project data is required in terms of geographic location, size, sequencing as well as technical parameters.

For this assessment, conceptual network designs were used as "building blocks" for integrated offshore network design options that were based on standardised arrangements, designed to be efficient taking account of current technology limitations and security of supply requirements. A "whole picture" approach for the development of integrated offshore network design options can inform selection decisions for specific regions, in terms of identifying conceptual designs that are available for use and those that would be expected to offer benefits.

Using a "development horizon" approach ensures that in principle, the integrated offshore network solution options identified are based on achievable technologies and designs across the whole timeframe for which the solution is required. A modular approach to the development of integrated network design solutions was used that allows for design reviews to take account of:

- step changes in capacity required at specific offshore locations;
- technology and design options that become available at latter stages of the development timeframe;
- efficiency improvements achieved since the original design stage;
- future developments and changes to other parts of the transmission system, and
- any additional opportunities for combining with other integrated offshore network developments.

A more holistic approach to transmission planning across onshore and offshore areas, can enable integrated offshore networks to be strategically and efficiently interfaced with the transmission system to:

- provide effective connections for generators located offshore;
- avoid excessive consequential reinforcement requirements on the existing transmission system;
- provide additional transmission system capability and operational flexibility, and
- provide support services (e.g. voltage, stability).

Integrating offshore network designs into the GB transmission system is not dissimilar in consideration to that of an onshore development. Design work should take account of the requirements of the existing transmission system and strategically interface with it. This approach could enable integrated offshore network design options to not only provide an effective form of offshore wind deployment, but also become an efficient element of the overall transmission system.

2.2. Comparison of Integrated Offshore Network and Radial Connection Design Approaches

To date, offshore wind farms have been connected to the transmission system by project specific radial connections. It is important to highlight that the project specific approach has been extraordinarily successful to date in delivering over 10 GW of offshore wind capacity growth within GB. However, in delivering over 40 GW of offshore wind farm capacity by 2030 and over 75 GW by 2050, it is recognised that the network development approach will need to evolve to meet the increased pace and scale required.

As part of this forward-looking assessment, both project specific radial connection (based on historic and current project activity) and integrated offshore network design approaches were considered. Table 2-1 provides a summary of the considerations.

Table 2-1 Comparison of project specific and integrated offshore network design approaches

Project Specific Design Approach	Integrated Offshore Network Design Approach
• Requirements for each project considered separately	• Takes account of possible future requirements
• Only considers point-to-point offshore network connections	• Considers a range of connection options including multi-terminal/meshed HVDC and HVAC options
• Individual project optimisation and transmission (HVAC or HVDC) decision	• Considers whole system optimisation and transmission technology decisions
• Onshore and offshore network designs are considered separately	• Considers effect on onshore system as part of offshore design development
• Interconnectors are designed and connected separately	• Possibility that interconnector/bootstrap capacity can be shared by an offshore wind farm
• Local community impacts are managed on a project by project basis	• Local community impacts considered on an overall impact basis

Figure 2-3 describes key differences between the possible offshore wind farm connections that could be identified (using a project specific radial connection or an integrated offshore network, design approach) to meet the offshore generation target for 2030.

Note that for the Integrated design 35% extra transmission capacity in 2030 supports installed OWF capacity up to 2032.

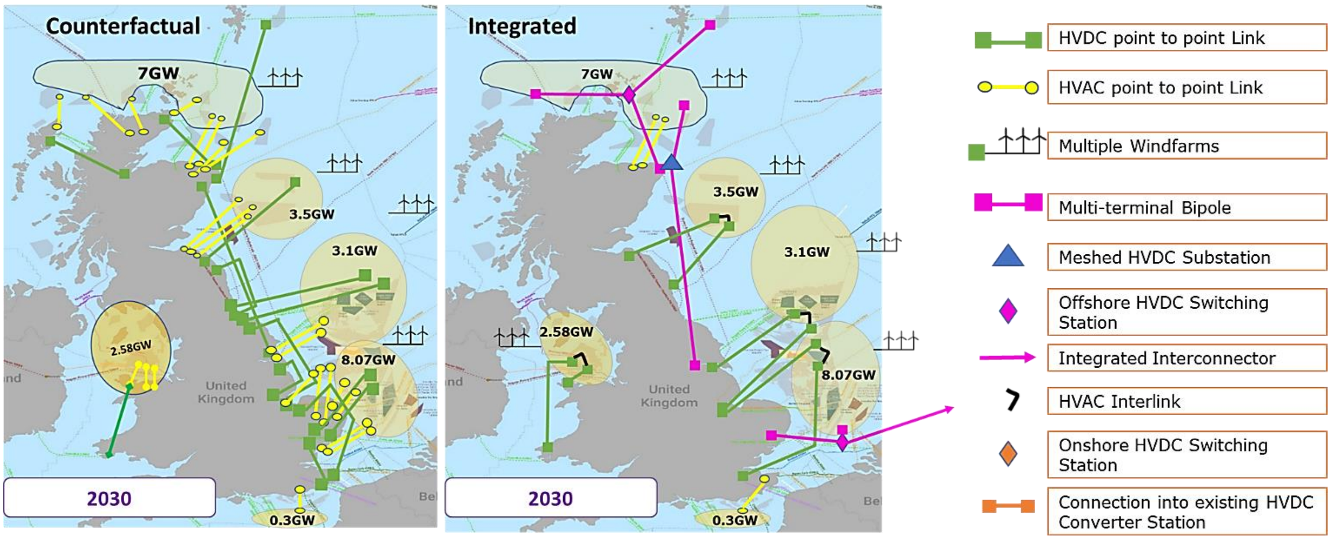

Figure 2-3 Comparison of project specific and integrated offshore network design approaches

Figure 2-3 illustrates potential widespread impacts upon the onshore transmission system in GB and on coastal environments of a project specific design approach. In addition, support for this larger volume of assets would require supply base considerations. Challenges that have been managed successfully on a project specific basis by offshore developers to date, will become amplified with the scale of future targets for offshore wind developments.

2.3. Our approach

It is recognised that project specific and fully integrated offshore network design represent two credible points on a wider spectrum of possible development approaches for the connection of new offshore projects (e.g. wind, interconnectors). As an example, an incremental approach that initially delivers a lesser level of integration could be proposed, however this type of incremental approach could be contradictory with the pace of offshore network development required. Possible network options identified using the project specific design approach were treated as counterfactual options for this comparative assessment.

A focus for this assessment has been to identify and analyse options for offshore network development that could accommodate the volume of new wind generation expected to require connection within the timescales defined within Government targets.

We have examined existing project data including that within the ESO’s Transmission Entry Capacity (‘TEC’) Register and FES. In order to avoid unreasonably disturbing or delaying offshore wind projects, we are not proposing an integrated approach for projects currently under development.

Our analysis assumes that there is a level of integration between 2025 and 2030, and this is what would be an ideal scenario to deliver maximum integration. However, from a practical point of view some of the assumed integration in the earlier stages of the designs may not be possible in reality, where projects are already at an advanced stage of development. Therefore, full integration before 2030, as envisaged in this analysis, may be not be achievable and changes may need to happen in a phased way for projects connecting in that period. This will impact on the extent to which the number of onshore landing points can be reduced by 2030 and potential savings by 2050.

Figure 2-4 describes the overall approach for this assessment.

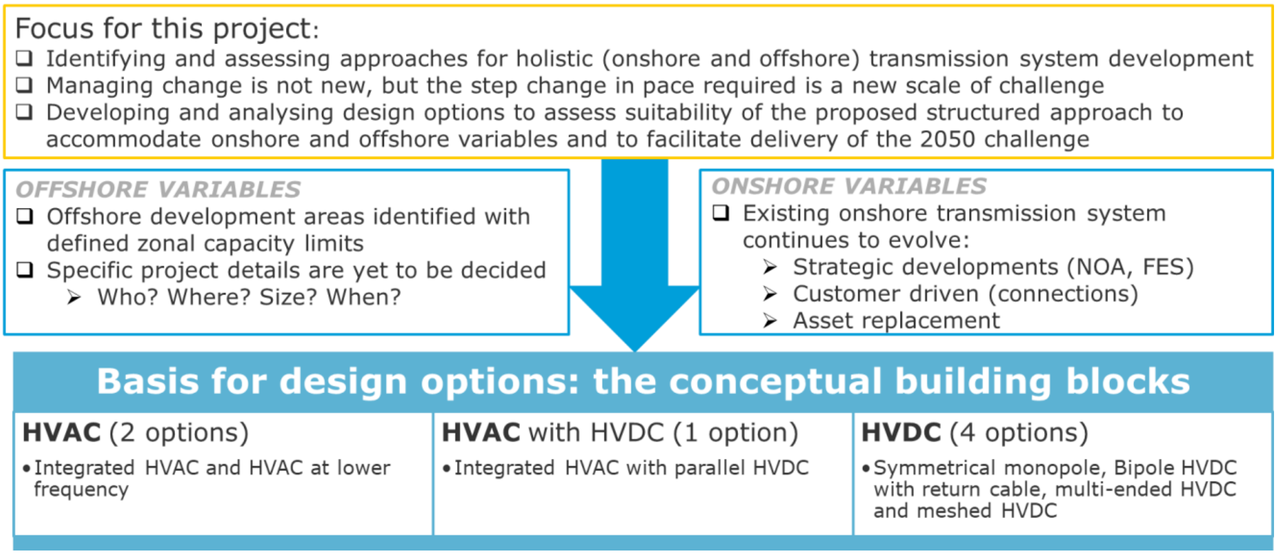

Figure 2-4   Overview of approach for this assessment

The evaluation process used to identify appropriate solution options, involved high level comparison of:

- Possible conceptual designs and their relative capabilities and merits, and
- potential application of design options to the regional areas of offshore development in GB.

These outcomes will be further described within section 4 of the report.

Our possible conceptual design choices were evaluated against a set of KPIs that were enhanced based on stakeholder feedback. These have been summarised at a high level in the areas described in

Table 2-2 below.

Table 2-2 High level KPIs used as part of this assessment (continues over page)

Security of supply	Impact on transmission system operation
• offshore connection meets current SQSS requirements • no reduction to level of overall transmission system security • level of availability of connection during outage conditions	• level of complexity of transmission system • flexibility that is available during operational (including real time) timescales • volume of ancillary services required • level of risk of operational failure • volume of transmission system losses
Technology limitations/readiness	**Shareability of transmission assets**
• capacity - power and voltage ratings • circuit length • track record of use	• can be used by more than one project • can offer opportunity to defer onshore reinforcements • can be delivered at pace that is required by transmission system users
Deliverability	**Potential for future development**
• can be delivered without major industry framework changes • technology up to 2030 is expected to be available and offered by manufacturers, and is used to illustrate beyond 2030 a conservative view of what can be achieved ahead of further innovation • technology readiness of design option used • technology has up to 2030 track record of use ahead of deployment • illustrative delivery of infrastructure ensured to be viable ahead of intended period of offshore turbine connection; allowing increasing time for this, the larger the size of connections being made	• design can be built in standardised modular chunks to align with pace of required developments • flexibility to be extended or modified • economically viable solutions are (expected to be) available (£/MW basis) • flexibility to adopt new design approaches and/or technology products
Achievability within current regulatory framework	**Environmental impacts**

• changes to regulatory framework, codes and/or standards needed?
• current rules sufficiently defined for offshore design option?
	• volume of assets onshore and offshore:
	  o above ground, and
	  o underground
	• size of new sites required
	• flexibility of site location for onshore equipment

KPIs were used to inform this assessment work and scored as either:

- Red (score 1) – overriding blocker or set of blockers to this approach being efficient
- Amber (score 2) - actions need to be taken to deploy efficiently or efficiency not yet proven
- Green (score 3) - in principle or in demonstration, have capability to realise the objective.

Within all areas of evaluation, each KPI was weighted equally.

2.4. Data inputs and assumptions

At the time of this assessment, the ESO's ETYS for 2019 had been published together with the NOA for 2020. We have referred to the insight on boundary analysis constraints and onshore reinforcements up to 2028/29 considered within the NOA, together with FES 2020 insights. Of the 2020 FES scenarios, only LW meets the pace and scale required to meet both the 2030 and 2050 offshore targets. Accordingly, our analysis of integrated offshore network design options has focussed on the LW scenario.

From the FES, the additional underlying data informing power system analysis datasets also informs integrated offshore design. In each area of the FES dataset ('FLOP zone') the ESO already makes assumptions on the scale of MW capacity offshore that may occur in a given year. This is based on the market environment and available Crown Estate and Scotwind data. Figure 2-5 summarises the build-up of this capacity towards 2050 offshore region totals.

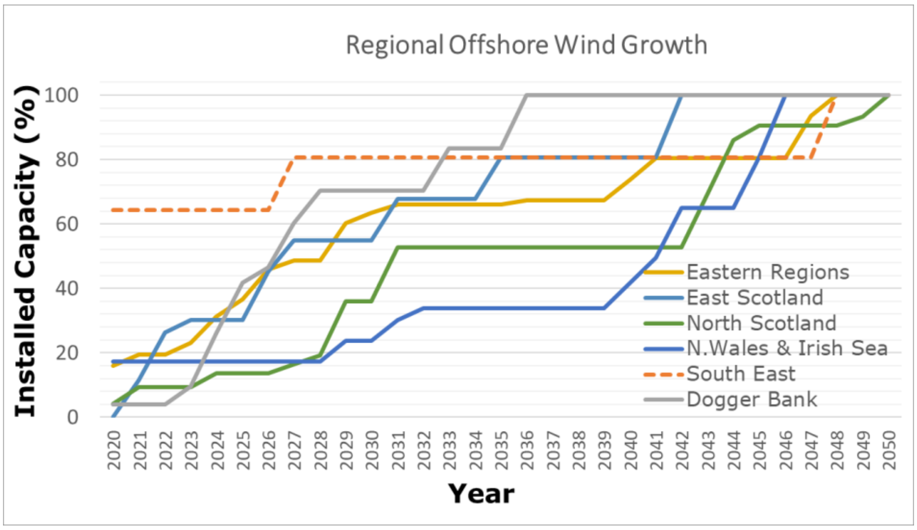

Figure 2-5 Incremental Build-up as a percentage of Installed Offshore Wind Capacity per region

Table 2-3 is a summary of the incremental growth in installed offshore wind generation capacity across the regional offshore wind development zones between 2025 and 2050.

Table 2-3 Incremental growth of installed offshore wind capacity up to 2050

Regional Offshore Development Zone		Incremental Growth of Installed Offshore Wind Capacity		
		Between 2025 and 2030	Between 2030 and 2050	Total between 2025 and 2050
1	North Scotland	4 GW	11.5 GW	15.5 GW
2	East Scotland	2.3 GW	4.2 GW	6.5 GW
3	Dogger Bank	3.1 GW	3.2 GW	6.3 GW
4	Eastern Regions	7.4 GW	10 GW	17.4 GW
5	South East	0.34 GW	0.4 GW	0.74 GW
6	North Wales & Irish Sea	1 GW	11.8 GW	12.8 GW
Total incremental capacity		**18.1 GW**	**41.1 GW**	**59.2 GW**

The above data represents offshore wind for electricity production purposes. These capacities include current offshore projects in development that have secured contractual rights to use the transmission system (transmission entry capacity - TEC) as well also other future, undefined projects which may be brought forward in future years as deadlines for offshore growth approach.

Year on year step changes in capacity by FLOP zone, represent future as yet undefined projects. Whilst FES data is aggregated regionally, it represents expected offshore capacity chunks and can be used to inform overall offshore network design solutions.

Figure 1-1 describes the picture of offshore development zones surrounding GB based on public domain GPS data provided by the Crown Estate and Scotwind. For some technology types, there are constraints which limit the viable circuit length. As part of this assessment, we have estimated the maximum geographical area possible for each type of conceptual network design option.

We have assumed that offshore developments to meet the overall Government targets will be distributed evenly across the offshore development regions that have already been proposed. Based on this assumption, maximum capacity possible from:

- HVAC solutions;
- HVDC extensions of HVAC areas, and
- Low Frequency AC ('LFAC') solutions

could be identified for a given offshore development area.

The assumptions surrounding what conceptual network designs are available would be expected to change over time, as technologies and potentially codes and standards evolve. As such, the relative merit of conceptual offshore network design options considered to be available can be expected to change over time. To drive that change in directions which would be expected to drive greater integrated design efficiency in GB, we consider that other complementary innovation and development strategies should be generated.

The following assumptions were made for this assessment:

- Design options must meet the minimum requirements that are defined in public documents (notably the SQSS and Grid Code). It is noted that governance arrangements are defined for each of these documents and therefore the minimum requirements can evolve over time.
- The range of design options for integrated offshore network designs will change over time as technologies evolve.
- The relative merit of design options is expected to change over time.
- Innovation and development strategies will be implemented across the timeframe to drive greater integrated offshore network design efficiencies,
- Technology that is available today or where a vendor would today be prepared to provide within the timescale required for that development, is considered to fit within the "development horizon".
- Offshore hydrogen production facilities expected to be developed from 2032 onwards, will not be connected to the transmission system.

Another set of assumptions specifically reflects on how the existing and planned infrastructure is treated:

- The conceptual designs assume that all of the transmission system reinforcements recommended to proceed in the Network Options Assessment for 2020 are built, up to and including in 2028. They therefore do not appear in the designs.
- Existing infrastructure and new projects that are planned to connect to the onshore network prior to or during 2025 are assumed to have been built as planned so are not included in the designs.
- Whilst projects due to connect from 2025 onwards are included in the designs, this may not be achievable in reality and changes may need to happen in a phased way for projects connecting before 2030. This will impact on the extent to which the transition from the status quo to Integrated option will be achieved by 2030 and subsequently 2050 and therefore the extent to which the number of landing points can be reduced, the amount and location of network required both onshore and offshore and the cost-benefit analysis.
- Individual lines represent indicative cable corridors, which where relevant will include several cables, rather than single cables. Multiple cables landing in a single location will require larger onshore infrastructure than individual cables and will take up a greater area of seabed. The lines should not be taken to be specific cable routes.
- These are conceptual network designs and further detailed analysis of many factors such as more detailed planning, coordination and operational analysis are required to turn these into specific plans to take forward. Consideration of further future energy scenarios, least worst regret analysis on the approach to take, seabed analysis and the impact on the environment and coastal communities would also be needed.

Table 2-4 below summarises our key data inputs and their sources/associated assumptions.

Table 2-4 Key data inputs, assumptions and rationale summarised

Topic	Data	Assumption	Reason	Notes
Offshore Capacity & timing	FES- GB waters only	Must be a background compatible with offshore targets	Task scope	LW scenario. Designs compatible with future meshed European grid expansion
Hydrogen production	FES	Not expected to be transmission system connected so not within scope for this assessment	Limited data & frameworks to inform integrated designs, no clear requirement in scenario to do so	Integrated designs flexible to relevant extension in this area
Regional Offshore development zones	FES	Crown Estate and Scotwind development zones - round 4 areas only	FES scenarios refer	Western Scotland assumed to be included in Irish Sea area, as no other FES allowance would include for Islay/ Colonsay project areas identified there
Offshore development zone project locations	Crown Estate & Scotwind GIS	Areas accommodate all new capacity within. Equally distributed within area	Support techno-spatial assessment of regional development area with attributed projects across period up to 2050 where existing projects do not exist	Identifies upper capacity limits by conceptual design options
Existing NOA projects	NOA	All NOA projects identified to proceed included	Offshore wind capacity in FES 2020 scenario exceeds range of NOA estimates within last NOA (as informed by FES 2019)	Reinforcements identified in NOA as not proceeding but identified as beneficial in power system analysis work have been highlighted.
Onshore Boundary analysis	ETYS	Desk top modification of ETYS results to reflect new offshore wind capacities and identify constraints. Integrated allocations of capacities treaded consistent with interconnector flow treatment in boundary assessment.	Focus implementation of the integrated offshore designs to support power system analysis	Desktop assessments followed by power system analysis- used to support first approximation of connection location and benefit of integration to be verified by PSA work.
Interconnectors	FES	Year-round load-factor analysis. Diverse connection routes and robustness to interconnector flow loss.	Enable integrated solutions with HVDC interconnectors where a beneficial solution.	New interconnectors and existing VSC-HVDC technologies considered; based on stakeholder feedback
Codes, standards and frameworks	Various industry documents	Existing Codes, Standards and frameworks apply. Where gaps exist assumption made that onshore system performance security or efficiency from the will not reduce from the levels these documents require	Evaluate benefits/risks and inform design choices	Overcoming barriers (section 9) identifies opportunities for code, framework and other potential improvements.

2.5. Stakeholder engagement and findings

To inform this assessment, feedback was sought from stakeholders across two project webinars - the first considering conceptual designs, technology availability and unit costs and the second covering application of conceptual designs to the GB system, power system analysis and overcoming barriers. At these webinars feedback was provided on the assessment work undertaken, but also on the approach taken. Figure 2-6 describes the key themes of stakeholder feedback received.

Stakeholder Feedback

Key Themes

- ❑ HVAC Technology Design Solutions
- ❑ Explore possible enhanced HVAC options
- ❑ Barriers in SQSS
- ❑ Application of technical and non-technical KPIs
  - ➢ Assess onshore impact particularly for local communities
- ❑ Technology options
  - ➢ Immediate future
  - ➢ Future developments

Actions we have taken

- ❑ Use of radial HVAC design building block as a counterfactual for analysis
- ❑ Investigation of integrated HVAC as well as HVAC/HVDC combi design options
- ❑ SQSS limitations have been flagged:
  - ➢ SQSS governance arrangements allow for specific modification proposals to be raised
- ❑ KPIs have been applied and onshore impacts assessed as part of our analysis of region specific design options.

Technology options – expected to be a changing picture

RECOMMENDATION
Ongoing review of:

- ❑ what is available
- ❑ what will come soon
- ❑ what is yet uncertain but is expected to offer benefits and solve existing issues.

Figure 2-6 Key themes from Stakeholder Feedback

Whilst most stakeholders recognise there is a need for change, views vary on the scale of change required as well as the need for a holistic transmission system development approach. Stakeholder views in respect of the approach needed for the future were diverse, ranging from a blend of integrated and non-integrated network solutions (assessed on a case-by-case basis) to centrally planned architecture that is suitable for meeting requirements into the future. All agreed that the pace of change is accelerating, and all welcomed the initial analysis of how:

- integrated solutions may be achieved;
- benefits may be realised, and
- challenges could be overcome.

The scale of offshore variables identified was generally accepted by stakeholders who agreed that use of the FES LW scenario was appropriate to provide an illustration for this assessment. Stakeholders agreed that offshore assessment that is aligned to existing onshore processes is desirable, although some noted areas of change that they consider are required in such processes.

Some stakeholders expressed concerns that the range of conceptual design options discussed at the first webinar are overly HVDC focused. The scope of the assessment was further enhanced by clarifying that the scope of the integrated network solution options could include HVAC technologies.

Stakeholder views in respect of technological development and innovation focus were diverse, ranging from there being a need to have a more forward-looking focus to concerns with any proposals to use solutions that have not yet been proven in an offshore environment. Some stakeholders who consider that certain conceptual designs should be given more innovation or development focus, provided preferred views upon the overall GB design options that should emerge.

With respect to meshed DC grids (one of the conceptual design options) concern was expressed surrounding the use of DC breakers, within an offshore context. Whilst no additional conceptual designs have been proposed at this time, some stakeholders noted that innovation could bring new designs forward over the analysis or during the offshore development period.

2.6. Example of our approach - consideration for the East Scotland region

Figure 2-7 illustrates this consideration for the East Scotland region.

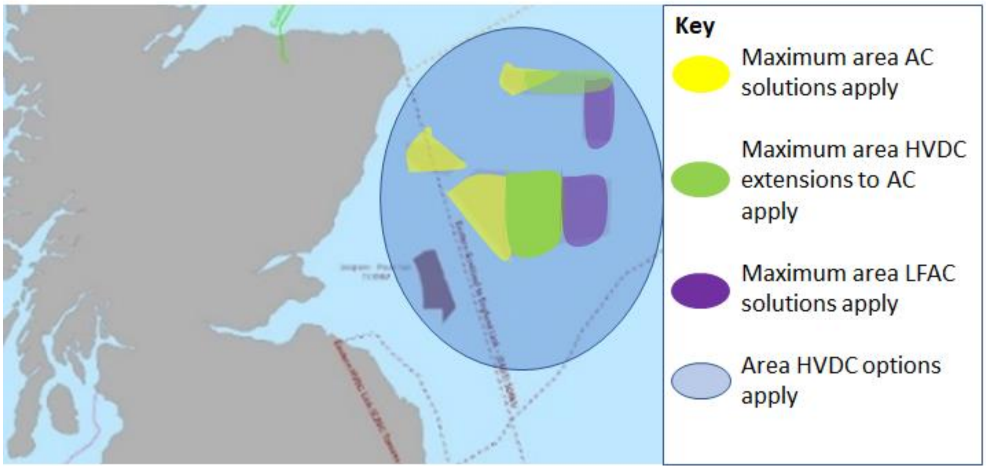

Figure 2-7 East of Scotland example of effect of technology applicability assumption

Using FES data by FLOP zone (in terms of capacity, location and build up required), it is possible to identify how much of that capacity could be connected by a given technology. The possibility for each project to be connected at a given scale economically and securely via a given technology was assessed (e.g. the maximum HVAC solution size possible before additional offshore infrastructure is also needed). Via this approach, given areas may be built up in representative proportions of technologies that are reflective of relevant general considerations for that offshore area. For example, individual project developers might pursue radial connection designs of the scales required and achieve a separate onshore connection. For integrated offshore design assessments, bounding the range of support each technology brings can ensure the maximum opportunity to make optimal design choices that offer flexibility to make different design choices in the future if assessment of onshore and offshore costs and benefits show that other choices are now available.

Noting the FES assumptions relating to interconnectors and comparing with the ESO's Interconnector Register, we identified new HVDC projects that are expected beyond the timeframes of 2028 FES datasets. Interconnector load factor data (at peak conditions and across seasonal operation) provided by the ESO was used, to understand the year-round capacity available. We limited the allocation of offshore wind capacity to no more than residual MW available once the maximum of these load factors across the year, is considered. In the cases where the interconnector is assumed to mostly operate in export of power from GB to the continent, we also applied a NETS SQSS assessment, treating the export power as a maximum load that could be lost to ensure that the intended maximum capacity of wind allocated to any integrated interconnector solution should not be unduly constrained. Finally, to ensure no single offshore wind area is wholly exposed to design restrictions, the opportunity to diversify offshore wind allocations to interconnectors and other routes via offshore interconnection between collector hubs using interconnectors has been included in all such designs.

Possible design solutions were assessed against the capacity objectives (including timing and geographic spread), as well as against relevant KPIs. The key areas of consideration are explained in more detail in section 4 of this report.

Conceptual offshore network design options combined to form possible offshore network solution options were combined with transmission system data. Findings from the DigSilent power system model following assumptions for this type of comparative assessment were:

- all activities identified in the 2019 NOA as committed or "proceed" will be delivered, as the LW scenario offshore development scale in the 2020 FES exceeds the value used in the 2019 FES (upon which the 2019 NOA is based).
- where a desktop examination of the capacities made available by existing onshore activity is conducted and shows:
    - a surplus capacity, integration would not be deployed unless value at a later stage is expected in a modular integrated solution being delivered.
    - power flow issues at an existing transmission system boundary, an integrated offshore network solution would be considered as a possible alternative to onshore transmission system reinforcement.

- in practice, all possible solution options (onshore and offshore network based) would be examined more closely as part of a future cross-optimisation process with onshore reinforcements within a future NOA process.

For this power system analysis, compliance with existing Grid Code and SQSS requirements are assumed. In the absence of specific requirements, an approach was adopted which is complementary to those with precedent in existing GB or international experience, to ensure that existing onshore network performance is not degraded. The following example the assumptions adopted as part of our analysis of integrated offshore capacity within onshore GB where requirements are not specifically defined in the existing regulatory framework:

- the capacity assumption for offshore wind behind a given onshore system boundary should align with the SQSS limits;
- non-network solutions (such as non-firm connections and/or associated restrictions to offshore generation) are not considered;
- integrated offshore solutions can parallel boundaries on the onshore transmission system and whilst the resultant capacity could cut across that boundary, such a cut would be relatively arbitrary in nature as the flexibility of the control of that solution and its connection capacity of circuits would be dominant; placing all the capacity of an integrated offshore network solution behind a given boundary would not be realistic, nor address the true boundary problem, and
- placing capacity of an integrated solution behind an offshore boundary could result in offshore connection assets needing to be treated equivalently to the onshore main integrated transmission system (MITS) but use of existing SQSS requirements would be not be realistic or justified.

There is precedent for assessing integrated networks connected to an existing HVAC system. The continental Europe HVAC system is connected to GB via multiple HVDC connections that parallel the transmission system. For boundary transfer consideration, net flows are allocated across interconnectors which are then represented at each point of connection with the transmission system in GB. We consider that for any type of an integrated offshore arrangement in parallel with a GB system, an approach where overall power flow is:

- identified (e.g. 70% of maximum capacity for an economy condition of offshore wind power output);
- allocated across the onshore landing points to minimise boundary challenge pre-fault, and
- potentially reallocated via offshore control actions post fault.

This approach of "injection analysis" was applied as part of the power system analysis of possible integrated offshore network design solutions that are discussed in section 7 of this report.

Another key design consideration is the maximum loss of power infeed loss risk permitted offshore. Designs of radial offshore networks today need to meet Chapter 7 of the SQSS in respect of maximum infeed loss risk across a number of contingencies relating to faults on the transmission system. The maximum normal infeed loss risk offshore is currently 1320 MW. Onshore, an infrequent infeed loss risk of up to 1800 MW applies.

The loss of power infeed risk limit is not only in respect of project specific connection arrangements. The European Connection Conditions ('ECC') (included as part of the Grid Code) also apply, which require generating plant to remain connected during transmission system fault conditions. Fault ride through performance of radially connected offshore wind farms can be demonstrated at an onshore interface point and specific requirements are defined in the Grid Code. The more complex integrated offshore network design solutions considered as part of this assessment, could be connected via a collection of HVDC circuits to more than one interface point with the onshore transmission system.

We recommend that the requirements in the SQSS (in respect of loss of power infeed limits) and the Grid Code (in respect of fault ride through requirements and associated compliance process requirements) are reviewed to ensure it is clear how these requirements apply to integrated offshore network design solutions.

3. TECHNOLOGY AVAILABILITY FOR OFFSHORE TRANSMISSION DESIGN

This section provides an overview of viable HVAC and HVDC technology options that could be used to connect offshore wind farms to the transmission system and discusses:

- the types of connection that could be delivered for each technology option using equipment that is (or is expected to be) available within development timescales;
- the main components required for each connection type considered as part of this assessment;
- the Technology Readiness Levels ('TRL') of the main components, associated control and protection systems and design topologies;
- possible areas where future development is expected, and.
- supply chain capabilities to deliver an increased volume of technology components.

The timespan for development covers a number of decades and it is expected that here would be many technological developments across that time. This assessment was confined to technologies that are already available and those that are being actively developed now, as a core aim of this project is to inform near future developments. Other technologies are discussed, such as LFAC, but were not deemed to be of a sufficiently high TRL to be realistically considered for offshore network developments by 2030.

HVAC has been the technology used to connect offshore wind in the UK to date. As developments increase in size and move further offshore, the technology is limited in its capability to transmit the required amounts of power to shore.

HVDC is expected to be a key technology relevant to future offshore transmission network designs. The most common solution to the challenges of increased capacity transmission, over long submarine distances globally is the use of HVDC which is already being used for interconnectors and in development for some distant wind farms both in Europe and Asia. HVDC technology has evolved from Line Commutated Converter ('LCC') technology reliant on a strong HVAC system to derive power to Voltage Source Converters ('VSC') which can act in a grid-forming mode. Grid forming modes allow VSC technology to provide certain levels of support to such weak networks if complementary types of control are implemented across that offshore HVAC network. These controls nominally encompass wide area control principles and certain complementary performance from the connecting wind turbines. However, such technology is often deployed in a manner which in comparison to the requirements of the GB transmission system's performance and ancillary services requirements, would appear more conservative in nature and purpose.

Today's VSC-HVDC links in Europe are mainly single point-point links that serve a single purpose (either interconnection, offshore wind export, grid reinforcement or power-from-shore), however examples of more ambitious control principles do exist. For example, the hybrid multi-terminal Interconnector arrangement of Skagerrak, Sweden, and the in development multi-terminal VSC Caithness-Moray-Shetland ('CMS') arrangement in GB which when complete in 2024, will be the first such arrangement in Europe. Point-point links are normally provided by a single vendor (one for the cable and one for both converter stations) and for VSC technology this is exclusively the case. Pilot radial multi-terminal HVDC projects have been built in China[4], comprising three converters stations and five converter stations, and a meshed HVDC grid with rated DC voltage up to 500 kV is under commissioning[5].

3.1. Overview of Offshore Technology

3.1.1. HVAC Offshore Connections

HVAC represents the conventional solution to transmission and distribution system connections that is used worldwide. Within GB, onshore HVAC transmission system voltages up to 400 kV utilise both overhead line and cable technology with capability of ratings up c. 3 GVA utilising multiple core connections. Offshore solutions however are limited by the practicalities of submarine cable shielding and associated insulation needs such that a maximum cable voltage of 220 kV is utilised. Noting the limitations of busbars as well as economic cable dimensions, translates to a maximum overall cable circuit capacity limitation of no more than 760 MVA and no more than 1,200 MW overall. HVAC technology is mature for near shore projects and has been in use for offshore wind export for more than 20 years. The main components of HVAC connections are described in the following sections, and an overview of an HVAC offshore connection is shown in the Figure 3-1.

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[4] https://www.tdworld.com/digital-innovations/article/20969421/china-upgrades-capacity-to-the-zhoushan-islands

[5] https://new.abb.com/systems/hvdc/references/zhangbei

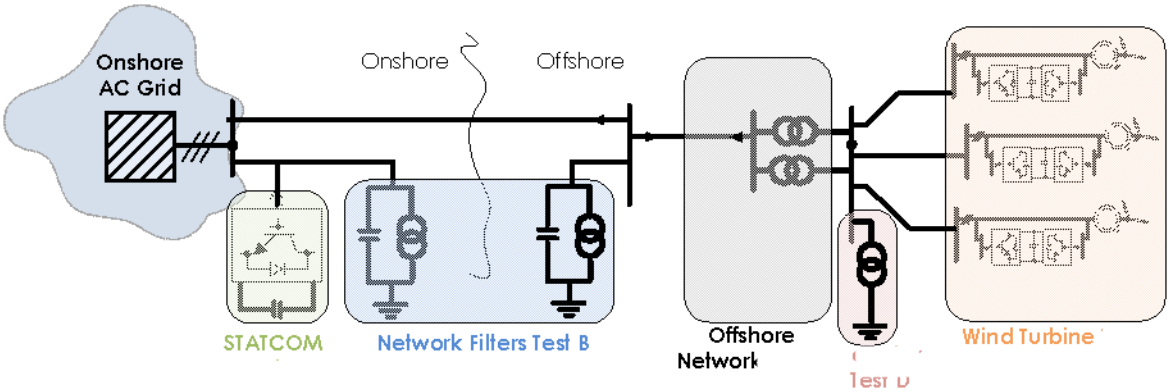

Figure 3-1 HVAC offshore connection

3.1.1.1. Onshore substation

In addition to the transmission system interface, other onshore HVAC infrastructure is normally present within a conventional windfarm design comprising the functions of:

- converting from the offshore transmission voltage to the grid connection voltage utilising conventional AC transformers.
- rationalising the numbers of cables landing to the available capacities of these transformers requiring an intermediate onshore substation,
- infrastructure such as reactors and dynamic compensation equipment (SVCs, STATCOMs, hybrid devices) and harmonic filters that can be used to satisfy required technical performance criteria onshore and supporting offshore voltage regulation.

The onshore substation typically contains the following primary equipment:

3.1.1.1.1.Switchgear

Whilst potentially operating at non typical voltages, the switchgear utilised is nevertheless of conventional design and function, and as such it is not necessary to repeat other industry discussion of its capability.

- Air insulated switchgear ('AIS') is highly mature technology with the ranges of offshore switchgear voltages deployed benefiting from a history of switchgear manufacture at these voltages and capabilities for over 60 years. AIS is normally used where space is less constraining and relies on natural insulation. Deployment in coastal contexts can however be problematic given the effect that saline pollution can have in degrading insulation and risks of broader areas of infrastructure degradation from direct exposure to that environment (for example moisture ingress impacting the mechanism of the switchgear). The naturally insulated environment allows for more flexible access, maintenance and development. Given the maturity and capabilities of the technology across a range of typical voltages and ratings, these components would not be expected to limit the capability of designs.
- Gas Insulated Switchgear ('GIS') provides a physically contained insulation medium allowing more compact substation arrangements, however the insulation media of Sulphur Hexafluoride ('SF_6) which is a known greenhouse gas, which in addition to strict targets for minimising leakage, legislation to limit the use of this gas and to seek replacement of it are underway at present. Again, GIS technology has had several decades of experience of deployment and a range of voltages and rating applications which would not present a limiting factor in deployment. GIS not being naturally insulated requires more care when discharging ahead of maintenance and is more sensitive to overvoltage driving other considerations within the context of insulation co-ordination study such as surge arrestor deployment to protect. The nature of its physically contained environment can lead to non-traditional ownership considerations. In general, the busbar of the switchgear and the busbar selector/isolator from it are within the same zone of insulation and need to be managed together. GIS options with alternative gases and clean air solutions that have a lower global warming potential in comparison to SF_6 are being actively developed by industry with real projects operating at voltages up to 170 kV.
- Hybrid – A combination of GIS circuit breakers and complementary AIS switchgear seeks to balance the above considerations. Again, application is well established over more than 30 years of use, and the switchgear approach does not limit HVAC solution capability or flexibility.

3.1.1.1.2.Transformers

Offshore transformers in function and characteristics are no different from those deployed within the onshore HVAC transmission and distribution systems. Transformer technology is well established over more than 60 years of experience transforming across voltages comparable to those utilised within conventional offshore HVAC systems. There is over 20 years of experience in the deployment of this technology in offshore context as well.

3.1.1.1.3.Reactive power compensation

As HVAC offshore connections have increased in capacity and length, many conventional power system operation conditions surrounding voltage regulation and management of harmonics have driven increasingly levels of and diversity in, the range of reactive compensation and tuned filter arrangements applied to offshore designs. As these projects have grown with HVAC submarine distances now out to approximately 200 km, frequently compensation devices are distributed across an offshore turbine collector substation platform, a mid-point compensation substation platform, and onshore substation.

- Fixed Reactors

  These are banks of fixed shunt reactors which are simple on/off devices providing voltage and reactive power support for certain system conditions. If there is a bank of reactors, they can provide certain amount of controllability by allowing switching individual reactors in the bank. Fixed reactor sizes of up to 300 MVA are available in the market. Specific reactor sizes will relate to the short circuit level at the points of connection. Tapped reactors are also available in which the amount of reactive power compensation can be controlled by means of a tap changer. These devices will be commonly deployed both at the mid-point compensation point and onshore landing point. Dependent on control strategy, the offshore wind collector platform will either use the wind turbine, an oversizing of mid-point compensation, or the siting of additional compensation at the offshore to compensate the network.

- Static Var Compensators (‘SVC’)

  SVCs use thyristors to produce either reactive power absorption or generation to regulate a given interface voltage – this is usually achieved via a voltage dependant droop control, which based upon the measured voltage proportionately modifies the reactive power absorbed or generated. Such controls are typically dynamic in nature – satisfying voltage deficits which may arise over timeframes of approximately 300 ms. Thyristors are inherently limited in their operational flexibility and as such SVCs do not “ride through” low voltages at the point of connection and may block operation below 10 or 20% of its normal value. Thyristors are limited in their speed of response, as each thyristor may only switch at a zero-crossing of the AC voltage waveform. Typical maximum device scale is around 250 MVA; these devices will nominally be installed within the onshore substation and scaled to support onshore Grid Code reactive range requirements (ECC.6.3.2). These will not normally restrict the capability of designs. One specific characteristic is the harmonic emission signature of such devices, the resulting voltage distortion requiring tailored filtering to the intended network design utilised.

- Static Synchronous Compensator (‘STATCOM’)

  Similar to an SVC, the STATCOM will in the steady state either absorb or produce reactive power based upon a droop-based control. Such devices, by use of a more flexible Inverse Bipolar Gate Transducer (‘IBGT’) device for switching, are far faster in response. They are capable of a full delivery of response within as little as 90ms of a non-fault disturbance[6], and potentially faster during a fault depending on the nature of its control. STATCOMs can both ride through and contribute to fault current. Some products also exist capable to provide a limited degree of power storage, allowing other potential control capabilities in inertia and stability support. As discussed within the ESO stability pathfinder project7, currently the largest such devices on the GB system is 225 MVA – this is not considered a limitation of conventional HVAC design. In control structure and voltage control these devices perform analogously to a single end of a VSC. Because of their speed, these controls need to be carefully tuned to avoid control interaction with other devices, and to take account of inherent control vulnerabilities (tracking of immediate reactive power to the system need across large signal events, e.g. faults, and small signal instabilities where positive feedbacks between networks and devices can lead to undamped oscillation and overall connection instability).

- Hybrid STATCOM

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[6] https://electricenergyonline.com/article/energy/category/t-d/56/835014/ge-energizes-the-largest-and-first-of-its-kind-statcom-scheme-in-europe-for-uk-s-national-grid.html

[7] https://www.nationalgrideso.com/research-publications/network-options-assessment-noa/network-development-roadmap

Hybrid devices are essentially a combination of fixed reactors and capacitors mechanically switched within an overall control strategy with a smaller STATCOM device which dynamically adapts across the switching. These devices can be slower or less flexible than a larger STATCOM within the first 5-90 ms of an event but are largely equivalent in behaviour over time periods slower than 300 ms. Given their hybrid nature, the performance of these devices has known mechanical and thermal limitations relating to multiple fault performance, as discussed within Grid Code review[8]. These devices represent a mature technology which is not representing a limitation upon conventional design.

- Harmonic and other filters.

  Filters provide frequency dependant absorption or damping of behaviours across a frequency range nominally up to 200th Harmonic, i.e. 10 kHz, achieved by a tuned combination of reactors and capacitors in parallel to define a fixed effect on nearby voltage. Whilst traditionally harmonic frequency background voltage distortion levels have been suppressed by such approaches, an increasing use of filters has arisen as part of wide area and local control and to damp small and large signal responses outside of the normal harmonic spectrum has evolved as the interfacing transmission system has become weaker in short circuit strength.

3.1.1.1.4.Protection, Control and telecommunication

These are combinations of Intelligent Electronic Devices ('IED'), telecommunications devices, relays, etc. in the form of panels that are used to control locally and remotely the switchgear in the substation, protect and isolate the faulty equipment, transmit and receive alarms and control from remote control centre. The control telemetry associated with wind area is mature in respect to steady state and dynamic control, however key aspects of measurement, signal latency.

3.1.1.1.5.Auxiliary service equipment

These are the miscellaneous equipment like transformers, battery banks, low voltage switchgear, heating, ventilation, air conditioning, lighting, building management system, etc. These are essential for the daily running of the substation both offshore and onshore.

3.1.1.2. Offshore substation

This is the substation that collects the power from the wind turbines and sends it onshore.

3.1.1.2.1.Offshore platform

The offshore platform is the most essential structure upon which the offshore substations are built. The offshore platform acts as the support for the equipment necessary to collect the power from the wind turbines using the cable array and step the power up to higher voltage and transmit it to onshore substation. There are different types of platform types upon which the substation could be built, mostly differentiated by the water depth and topside weight.

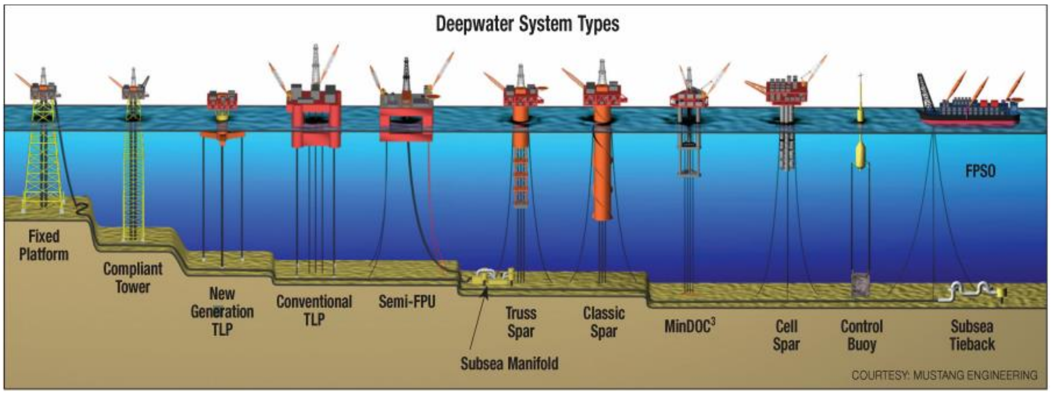

Figure 3-2 Types of Offshore platform

Figure 3-2 shows the types of oil platforms – similar platforms would be used for the offshore substation as well. To date, only fixed platforms based on monopiles, jacket structures, or gravity-based structures have been used for offshore substations. More information on platforms could be found is available in literature[9]. In order to minimise topside weight, a GIS switchgear technology is commonly utilised and

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[8] https://www.ofgem.gov.uk/publications-and-updates/grid-code-gc0075-hybrid-statcomssvcs

[9] "The Crown Estate – UK Market Potential and Technology Assessment for floating offshore wind power".

where possible the balance of equipment required in any design is moved to shore. Savings in topside weight and space have direct correlation with the platform availability and its cost.

3.1.1.3. Array Cable

The wind turbines usually generate the power at 690V to 3.3 kV which is then transformed to HVAC voltages up to 66 kV using the transformer in the wind turbine and then transported by radial array cable network to the offshore substation. The collection of HVAC power submarine cables that connect the wind turbines to the main step-up transformer in the offshore substation is known as the inter-array cables. More information on the collection system can be found in literature[10]. This array topology is common to both HVDC and HVAC arrangements.

3.1.1.4. Land fall point

This is an important part of the connection as land point selection will have significant implications for the consideration of a range of amenity and broader environmental considerations associated with the project. HVAC cable easements are typically wider in comparison to equivalent voltage HVDC corridors. This combined with the higher number of HVAC cables required to satisfy the equivalent HVDC corridor drives a greater disturbance of both the landfall itself and its route to the onshore substation itself.

3.1.1.5. HVAC Cable

This is the high capacity power cable that connects the offshore substation to the onshore substation for the transmission of power from the wind farm, to the onshore transmission system. Depending on the power, type of insulation and the distance over which power is being transmitted, HVAC cables can be single three-core cables at lower voltages or three single-core cables for each phase at high voltages. Mostly XLPE cables are used for HVAC application, with three-core cables rated at HVAC voltages up to 220 kV and power ratings up to 400 MW per cable. More information on HVAC cables can be found in literature[11]. List of HVAC offshore wind connection in UK Appendix A contains a list of existing offshore wind connection that has been built till date in UK.

3.1.2. HVDC Offshore Connections

HVDC transmission systems are used to transfer large amounts of power over long distances. It is especially useful for long distance submarine cable transmission for offshore integration with fast controllability. HVDC grids for offshore application consist of three main parts as shown in Figure 3-3:

- offshore HVAC system – where the wind energy is produced and output as HVAC power,
- offshore HVDC system – where the wind power is transmitted to an onshore HVAC grid via a HVDC connection,
- onshore HVAC system – where the wind power is fed into the HVAC grid.

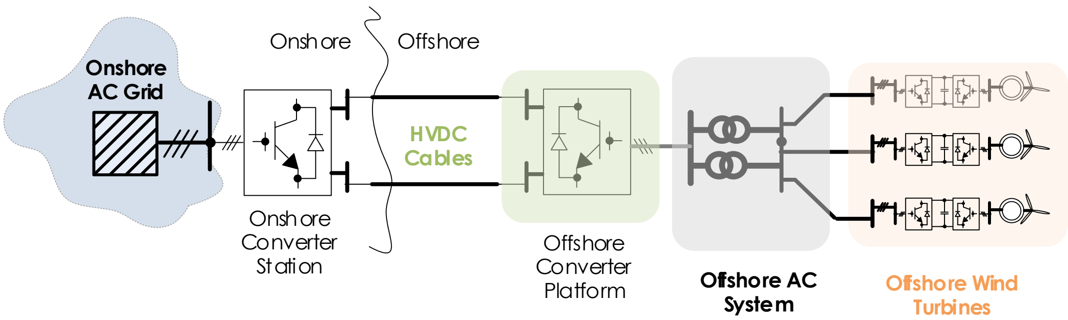

Figure 3-3 Overview of HVDC offshore wind connection

Key building blocks of these systems are detailed in the following sections.

[10] S. M. Alagab, "Review of wind farm power collection schemes," 2015.

[11] X. Xiang, "Cost Analysis and Comparison of HVAC, LFAC and HVDC for Offshore Wind Power Connection".

3.1.2.1. Converter Technology

The two main technologies that are used in HVDC are LCC and VSC. There are developments ongoing with alternative options.

In LCC technology the converters use high power thyristors in a twelve-pulse bridge form. Thyristors can only be turned on and require a zero crossing of the AC voltage to turn off. Thus, these converters usually rely on high system strength (a short circuit ratio of 2 or more) in both rectifier and inverter side to maintain and provide the AC voltage zero crossing for natural commutation (switching) of the converter. A typical converter arrangement of an LCC HVDC link is shown in Figure 3-4. As these converters are not capable of black-start / islanded mode on its own and it is not possible to have high system strength at the windfarm side, they are not suitable to be deployed in offshore wind projects[12].

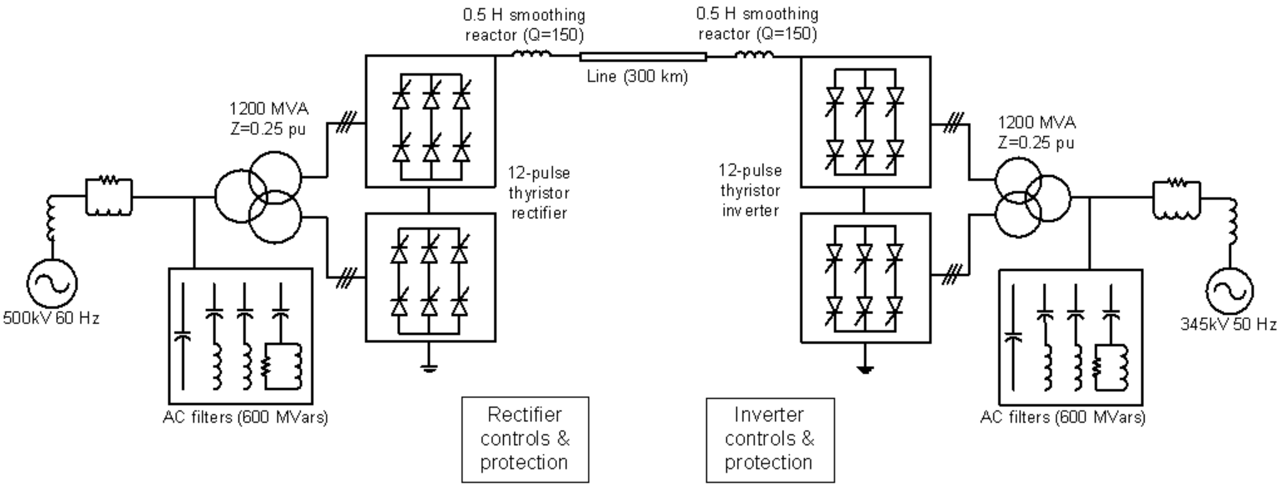

Figure 3-4 Typical 12 pulse LCC monopole arrangement

VSC converter uses high power IGBT which is a newer technology than the thyristor. These IGBTs can both be turned on and off using the gate pulse, so they are fully controllable and hence they don’t depend on the system condition for their operation. This allows VSC converter to black start and operate in islanded mode. Thus, they are most suited for offshore wind energy connections. As the VSC converters can switch as many times as needed in a single cycle, they can reproduce a smooth HVAC voltage with minimal harmonics, so they generally don’t require filters.

Most of the VSC-HVDC systems built until 2012 were based on the two-level VSCs, as shown in Figure 3-5 (a) or cascaded two-level converters (CTL). VSC-HVDC systems are now mostly based on the Modular Multilevel Converters (MMC), more specifically, half-bridge (‘HB’) and full-bridge (‘FB’) MMC, as shown in Figure 3-5 (b & c). The HB MMC converter is the most commonly used converter topology as they are cost efficient and have lower losses when compared to FB converters. The FB converters have HVDC fault current blocking capability, so they are preferred in special applications where HVDC fault currents are supposed to be blocked. Convertor classification based on their fault-handling capabilities is available in literature[13].

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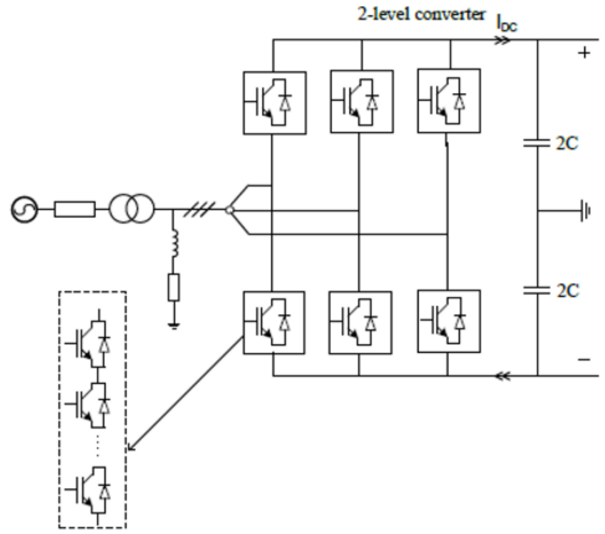
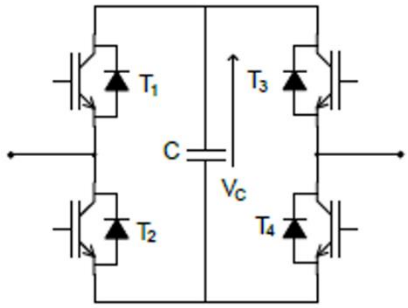
12 http://www.emrwebsite.org/hardware-in-the-loop-of-electric-drives-and-power-electronic-systems-using-rt-lab-pc-clusters-and-fpgas.html

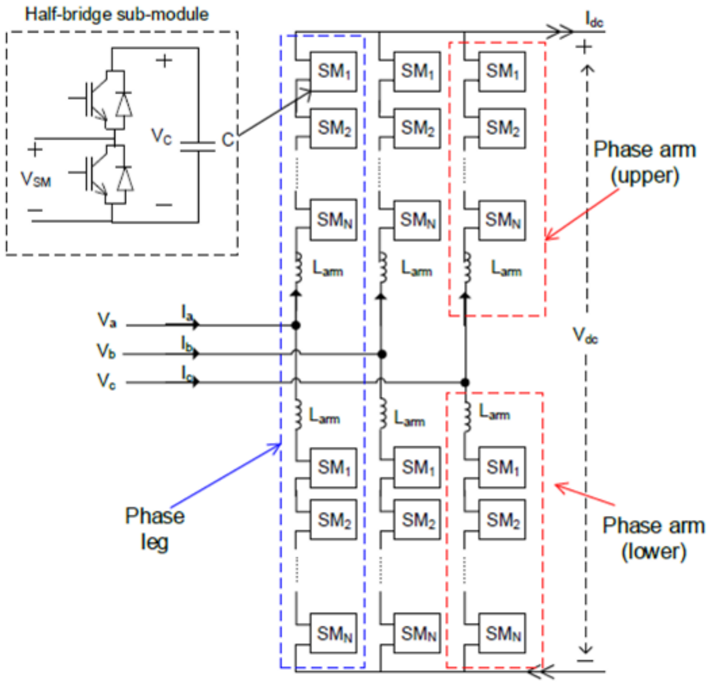
13 Judge, Paul D., Geraint Chaffey, Mian Wang, Firew Zerihun Dejene, Jef Beerten, Tim C. Green, Dirk Van Hertem, and Willem Leterme. "Power-system level classification of voltage-source HVDC converter stations based upon DC fault handling capabilities." IET Renewable Power Generation 13, no. 15 (2019): 2899-2912. https://pdfs.semanticscholar.org/b9d3/eb2b317faacfb9b088bdfa9b8ebf39bdb25d.pdf



a. Two-level converter



b. FB MMC submodule



c. MMC with HB submodule

Figure 3-5 VSC Converter Topology

There are many other topologies that are being proposed and researched. Examples include hybrid converters with thyristors and IGBTs and converters with a combination of HB and FB submodules, but they are at very low TRL.

A specific offshore option being investigated is the use of Diode Rectifier Units ('DRU') with a view to reducing the complexity and size of the offshore equipment. In this scheme the offshore VSC HVDC converter is replaced by a twelve-pulse diode rectifier with smoothing reactors, the onshore VSC remains the same as normal VSC HVDC link. This design results in increased availability if a FB MMC VSC is used. This diode-based rectifier is the simplest form of HVAC converter available and has no controllability, the AC-DC conversion is totally based on the natural passive conduction characteristic of the diode. As this diode rectifier doesn't need any power control or firing control, the simple diode rectifier could be combined with transformer and smoothing reactor into a single unit referred to as a DRU. Since the diodes are oil insulated, they require a lot less space than the air insulated valves of an MMC VSC station and is thus a lot more compact to build leading to further cost advantages. This type of DRU considerably reduces the complexity and size of the offshore substation.

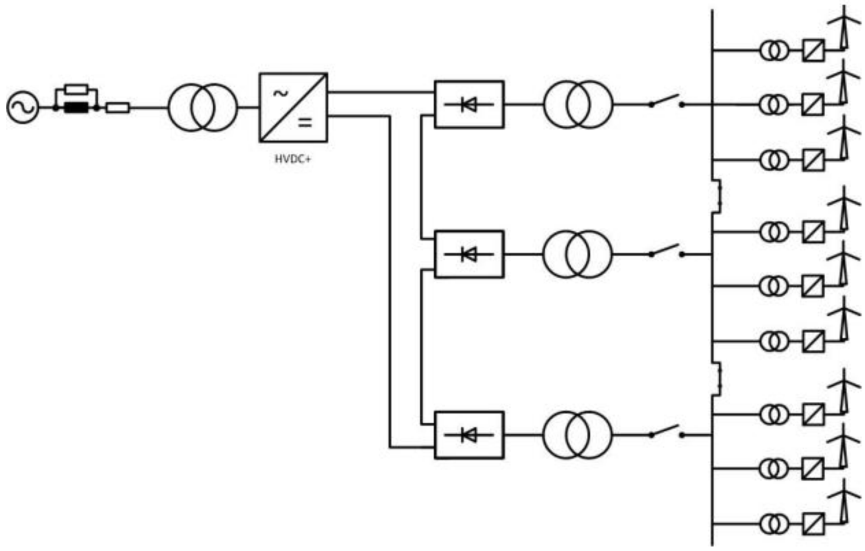


Figure 3-6 DRU based HVDC offshore wind connection scheme

The DRU lacks the ability to regulate the offshore HVAC network. This means that wind turbine ('WT') converters must control the offshore HVAC network's voltage and frequency. On this accord, the WT controls must be expansive enough to control the power, voltage, frequency and ride through onshore HVAC faults as required by the Grid Code. Several control schemes for such expansive controls are proposed theoretically and have been demonstrated in dynamic performance tests, but there are no real implementations in any project.

As with the DRU solution detailed above, it is possible to have hybrid convertor technology solutions. For offshore, this could mean using a VSC convertor offshore and LCC convertors onshore, where there is a grid to support the commutation of the valves. This has been implemented in a real project in China, the WuDongDe 3-terminal HVDC system. The WuDongDe system has a rectifier LCC station and two inverter VSC stations.

3.1.2.2. Converter Configuration

Considering the configuration of converters, which would influence the operation and performance of the offshore DC system, different options are available as follows:

Asymmetric monopolar – a single HVDC cable is operating with an earthed return, as shown in Figure 3-7. Using the earth as return path might cause several environmental impacts and therefore this configuration is mostly not used. It can be used if a metallic return is available. The full transmission capacity is lost during a pole-to-earth fault. A pole-to-earth fault creates a large fault current which has an impact on the connected HVAC grids. Special transformers which can withstand HVDC voltage stress are required in this converter configuration.

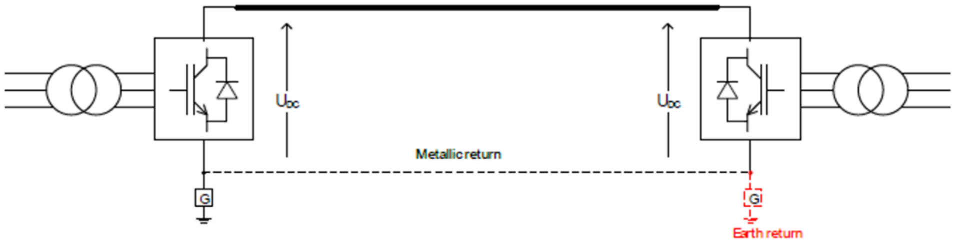


Figure 3-7 VSC monopole configuration

Symmetric monopolar – two HVDC cables connect two converters with same magnitude but opposite polarity, as given in Figure 3-8. Earthing can be provided by stray capacitance of HVDC cables, or dedicated HVDC capacitors, or at HVAC side using a star reactor etc. This option is most commonly configuration in VSC converters in offshore wind export applications. The full transmission capacity is lost during a pole to earth fault. A pole to earth fault does not create large fault current so the impact on the connected AC grids is limited. The healthy pole does experience an overvoltage which can stress the components. No HVDC voltage stress is experienced by transformers in this converter configuration, so regular HVAC transformers can be used.

Figure 3-8 VSC symmetrical monopole configuration

Bipole – two converters are connected in series at each terminal, as illustrated in Figure 3-9. One is between the positive pole and the neutral midpoint, while the other is between the neutral midpoint and the negative pole. The midpoints can be connected via a low voltage metallic return conductor. If a metallic return is used, then there is redundancy for either a converter or cable fault by allowing operation as an asymmetric monopole. It also allows for asymmetric operation of the poles by giving a current return path during normal operation. If no metallic return is included then it would need to be operated with the poles balanced, referred to as a rigid bipole. This configuration still provides the feasibility to have some level of redundancy as they could transmit half the power when one of the converters is faulty using monopole metallic return configuration. Potentially only half the transmission capacity is lost during a pole to earth fault. A pole to earth fault also creates a large fault current which has an impact on the connected HVAC grids. Special transformers which are capable of withstanding a HVDC voltage stress are required in this converter configuration.

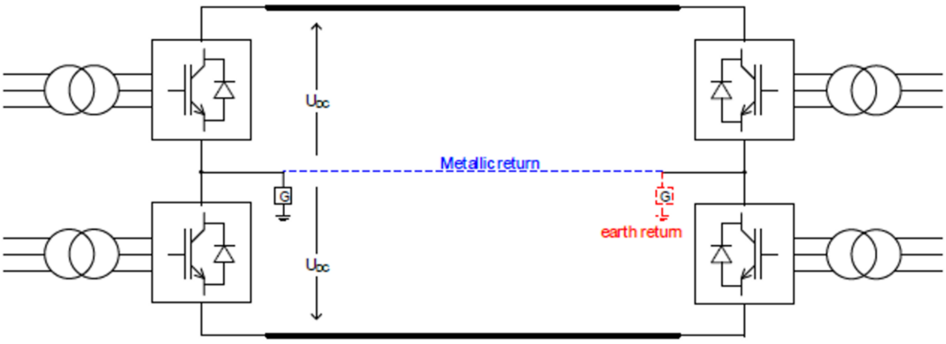


Figure 3-9: VSC bipolar configuration

3.1.2.3. HVDC Cables

HVDC submarine underground cable enables the power transmission from offshore to onshore. The rating of the cable is a function of the voltage and the current. The current rating of the transmission cable will be dependent on aspects such as:

- Area of the conductor and conductor material
- Cable design, choice of insulation technology and materials
- Installation conditions surrounding the cable typically including:
    - Depth of burial,
    - Thermal resistivity of the medium surrounding the cable,
    - Proximity of other circuits and
    - Ambient temperature.

Cable ratings will need to identify any area where there is a change to the installation conditions, broadly speaking, there are three regions of primary interest along the route. These are:

- Main sub-sea section,
- Land fall, and
- Installation on land.

At these points, the cable will experience a change in its installation conditions and cable system design and thus a change in current rating and power rating.

There are several options available for HVDC cables based on the insulation types:

- Mass impregnated ('MI') cable;
- Self-contained fluid filled ('SCFF') cable; and
- Extruded cable.

Due to the wider supply chain, lower cost and better thermal performance, extruded cables – especially XLPE insulated cables – are becoming widely used and dominating new installations. New types of extruded cable utilising polypropylene are also being introduced into the market but are not operating at 320kV. Their advantage is higher thermal rating than European HVDC XLPE and less complexity in manufacturing (no crosslinking or degassing). This leads to faster production and also widening of the supply chain. It should in principle drive the prices of HVDC cables down once established as a reliable technology.

Mass impregnated cables have a much larger bending radius than their XPLE equivalents, this would make them more expensive to install as cable-laying ships can only carry shorter sections requiring more laying expeditions and therefore more time and or resource. Further impacting the installation time and cost is that the joints for take much longer to make for mass impregnated cables, approximately a week versus a day for XLPE.

Across the different manufactures and technologies there are differences in the operating voltages available. NKT claims to have fully validated 640 kV XPLE[14] cables however project experience is below this level. Rating availability will be discussed further in the TRL assessment.

14 https://www.nkt.com/products-solutions/high-voltage-cable-solutions/innovation/640-kv-extruded-hvdc-cable-systems

3.1.2.4. Platforms

The platform technology would be similar across HVAC and HVDC options, even though HVDC platforms typically require much larger topsides and therefore more complicated installation techniques, please refer to the information provided in 3.1.1.2.1.

3.1.2.5. Array Cable

It is expected that the cable array would be the same across both HVAC and HVDC options, please refer to the information in 3.1.1.3.

The recent exponential growth in the number of offshore windfarms has triggered research in the feasibility of HVDC collection systems with several topologies having been proposed and studied but there is no real-world implementation yet. The general arrangement for such a HVDC collection system with two DC-DC converters is shown in Figure 3-10.

In this HVDC collection system, the AC power generated by the windfarm is converted into DC power at medium voltage DC ('MVDC'), by the first DC-DC converter that is suitable for the HVDC collection system. The MVDC is then stepped up to HVDC for transmission using the second DC-DC converter. Then this DC power is transmitted to the onshore using the HVDC cable and converted back to HVAC using the onshore VSC converter and synchronized with the onshore HVAC grid. These DC/DC convertors would be different to the convertor technology otherwise considered in this report, further details can be found in literature[15].

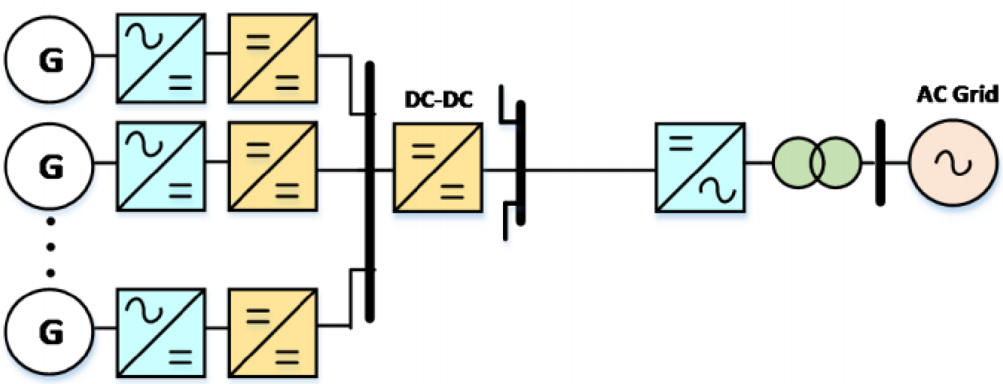


Figure 3-10 HVDC Collection system for offshore windfarm

The proposed advantages of this approach are that:

- the bulky ac transformer used to step up the ac voltage generated by the wind turbines are removed which can reduce the size of the equipment needed in the wind turbine considerably, and
- it considerably reduces the size of the offshore substation as it removes the need of HVAC switchgear and HVAC step-up transformers.

Some challenges in this system that are yet to be addressed in real life projects are: the coordinated implementation of HVDC control and HVDC protection scheme for such large-scale collection system; and there are additional losses because of the additional DC-DC converters.

[15] Zhan, C., C. Smith, A. Crane, A. Bullock, and D. Grieve. "DC transmission and distribution system for a large offshore wind farm." (2010): 46-46. https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=5728013

- "Novel 5 MW DC Converter Put Into Operation" https://www.eonerc.rwth-aachen.de/cms/E-ON-ERC/Das-Center/Aktuelle-Meldungen/~dlnpc/Erster-5-MW-Gleichspannungswandler-in-Be/lidx/1/
- "1 Megawatt, 20 kHz, Isolated, Bidirectional 12kV to 1.2kV DC-DC Converter for Renewable Energy Applications" https://www.hpe.ee.ethz.ch/uploads/tx_ethpublications/24G3-1_02.pdf
- T. Lagier and P. Ladoux, "Theoretical and experimental analysis of the soft switching process for SiC MOSFETs based Dual Active Bridge converters," 2018 International Symposium on Power Electronics, Electrical Drives, Automation and Motion (SPEEDAM), Amalfi, 2018, pp. 262-267, doi: 10.1109/SPEEDAM.2018.8445413. https://ieeexplore.ieee.org/document/8445413

3.1.2.6. Converter Substations

HVDC converter substations consist essentially of converter valves with their control and protection systems, including auxiliaries. HVDC Converter substations are normally air insulated which leads to relatively large volumetric footprint requirement. There are two basic applications of HVDC converter substations: back-to-back AC-DC-AC converter stations, and long-distance HVDC transmission terminal substations which are separated by a transmission line or cable. For offshore interconnections, the latter one is applied to interconnect the offshore AC wind power plants with the onshore HVAC grid.

3.1.2.6.1.Control and Protection System of HVDC Converter Station

The control and protection systems of the HVDC converters are of key importance. The control and protection system are a complex combination of hardware components like Digital Signal Processors ('DSP'), computers, I/O boards, transducers etc and software logics embedded in hardware. Unlike with traditional HVAC transmission assets which are passive, the control of the converters will define the operation of the HVDC system and its interactions with the HVAC networks.

More details on the Control and Protection System of HVDC converter station are given in Appendix D.

Auxiliaries

Auxiliary system consists of

- AC auxiliary power system
- UPS battery rooms and DC power system
- Fire detection and protection system
- Air conditioning system
- Valve cooling
- Heli deck

The auxiliary systems with their components, which have been installed and are in commercial operations in converter stations, are seen to be technology mature and can be applied to HVDC offshore directly.[16]

3.1.2.7. DC Chopper / Dynamic Braking System ('DBS')

This device serves multiple purposes. Two key functions are that it protects the DC network from overvoltage and allows the HVDC system to ride through HVAC system faults. When moving to integrated HVDC grids it will also rebalance the poles to allow continued operation of the HVDC grid after clearing a HVDC fault.

In the point-point connected offshore windfarm for a fault in the onshore HVAC grid either a DC Chopper along with the series resistor or DBS would act as a firewall by absorbing the excess power generated by the windfarm that cannot be transmitted to the onshore grid during the fault. But for the fault on the offshore AC grid there needs to be special controls in the offshore HVDC converter and the WT generator converter to enable fault ride through during the period the protection system takes to clear the fault.

[16] M. Rahaman, "Development and Validation of Offline and Real-time User-defined Models of Alternative MMC Configurations".

ABB, "HVDC Light It's time to connect".

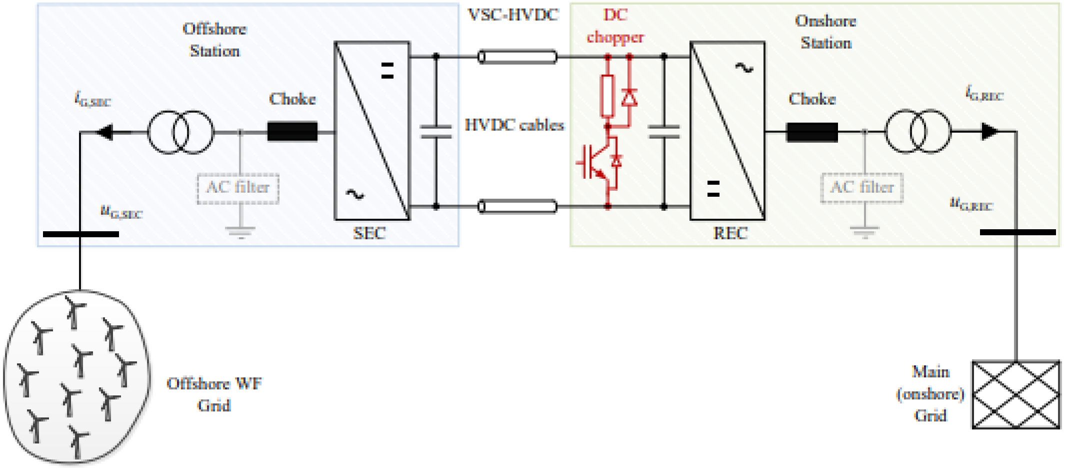


Figure 3-11 DC Chopper in an onshore converter station

Typically, the DC chopper/DBS are in the HVDC side of the onshore converter station as this avoids the need for a bigger offshore platform. Functionally this arrangement provides the same benefits as placing the DC chopper/DBS in the offshore converter station as the HVDC cable included in the circuit, is mostly in service and cable faults are very rare in occurrence.

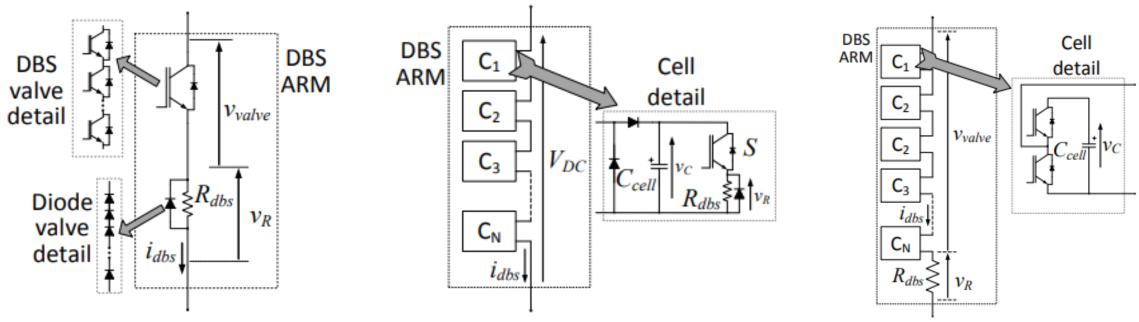


Figure 3-12 Different type of dynamic braking arrangements

There are different types of resistor and power electronic switch arrangements that are typically used by various manufacturers the same is shown in Figure 3-12. More information on DC choppers /DBS could be found in literature[17].

3.1.2.8. Switchgear

Compact HVDC switchgear is needed for HVDC cable connections in offshore applications. Traditionally, AIS is used to connect HVDC circuits. However, AIS requires larger clearance and creepage distance, which results in a large switchgear footprint, especially in multi-terminal 'ready' converter stations/platforms. GIS has been under development by various manufactures for several years. It can potentially save much space, which comes at a high premium for offshore HVDC grid. It is estimated that the volumetric space of the GIS installation itself can be drastically reduced e.g. by 70%- 90% compared to AIS. This could result in a size reduction of circa 10% of the overall converter platform.

So far, there are no international standards on the specification requirements, applicable tests and test procedures for HVDC GIS. The project PROMOTioN has conducted a long-term test on 320 kV HVDC GIS, with recommendations on specifications and test procedures. A demonstration project has been undertaken where a DC GIS suitable for 550 kV was created[18].

[17] J. M. M. Barral, "AN INVESTIGATION OF AN ENERGY DIVERTING CONVERTER FOR HVDC APPLICATIONS"; and M. Suwan, "Modeling and Control of VSC-HVDC Connected Offshore Wind Farms".

[18] Maria Kosse, Karsten Juhre, Mark Kuschel, Dejun Li, "Overview of development, design, testing and application of compact gas-insulated DC systems up to ±550 kV," Global Energy Interconnection,
Volume 2, Issue 6, https://www.sciencedirect.com/science/article/pii/S2096511720300116

3.1.2.9. DC Grid Protection

The protection of a HVDC grid is fundamentally different to that of an HVAC grid. Both the rate-of rise and steady state value of fault current is very high. Since the reactance of HVDC cables is negligible, a fault at any point in the HVDC grid will cause widely spread voltage collapse, HVDC overcurrent and VSC converter tripping if the HVDC fault is not cleared timely. There is also no natural zero crossing to break the fault current so one needs to be introduced as part of the protection sequence.

3.1.2.9.1.Philosophies

There are three basic types of protection philosophy that could be considered:

- non-selective, where there are no protection zones or the entire HVDC grid is treated as one zone;
- partially-selective, where the HVDC grid is split into several protection zones or sub-grids, and
- fully-selective, where protection zones are defined to individually protect each line and bus (as is used on the HVAC system).

Until now, with the existing point-to-point connections, and with CMS (the first multiterminal HVDC design in Europe) non-selective schemes have been used. This is where any HVDC fault takes out the full link and the fault is isolated by the HVAC breakers at each of the converters. As the offshore grid develops further – as soon as there is an interconnection on the HVDC side – it is expected that this approach would cause an unacceptable loss of infeed and / or availability of transfer capability.

Extensive research has been carried out across the different options including comprehensive comparisons of the different approaches[19]. Feasible options have been developed for each of the strategies, but they have different trade-offs with regards to system impact (both HVAC and HVDC), operability, cost and extensibility.

As soon as something other than non-selective using HVAC breakers, is used then additional (or alternative) equipment is required to be included in the design to facilitate the protection of the grid. Some combination of the following devices would need to be used: superconducting fault current limiter; DCCBs; and/or FB converters.

Selection of different philosophies for links which are then interconnected, does not necessarily mean that they would not be compatible[20]. The complexity of the future design would increase and would therefore be likely to be less efficient overall, given the extra investment that may be required to facilitate the interconnection.

3.1.2.9.2.DC Circuit Breakers

DCCBs provide a means of limiting the loss of infeed due to a fault event in larger HVDC systems by allowing healthy branches to remain in service after (and in some cases during) a fault. The requirement for using DCCBs in offshore networks is determined by the network topology as well as by the protection strategy. They are required for partially and full selective protection schemes and some variants of non-selective schemes.

In case of the use of a DCCB, the fault current needs to be limited to meet the limited short-circuit current interruption capability and breaker operation time of the DCCB, by either the inclusion of a superconducting fault current limiter or an inductor. The size of the inductor would range from 10's to 100's of millihenries depending on the protection philosophy, technology choice and system topology.

Unlike HVAC breakers, DCCBs are active devices as they must generate a local current zero crossing to interrupt the fault current before they can successfully open and clear the fault. This means that DCCBs have a large footprint and are more like a convertor station than a traditional HVAC breaker.

DCCBs have not been used at transmission levels in Europe (there are three projects in China) since almost all the VSC-HVDC systems in operation today have been developed as point-to-point systems. A fault in a point-to-point HVDC can be isolated by tripping the HVAC circuit breaker at both terminals. Since the reactance of HVDC cables is negligible, a fault at any point in the HVDC grid will cause widespread voltage collapse, DC overcurrent and VSC converter tripping if the HVDC fault is not cleared timely.

There are three basic types of DCCBs:

- Semiconductor-based
- Mechanical, and

[19] https://www.promotion-offshore.net/fileadmin/PDFs/D4.2_Broad_comparison_of_fault_clearing_strategies_for_DC_grids.pdf

[20] P Düllmann, P Ruffing, C Brantl, C Klein, R Puffer, 'Interoperability of DC protection strategies based on fault blocking converters and DC circuit breakers within a multi-terminal HVDC system', DPSP 2020

- Hybrid – a combination of semiconductor and mechanical.

In several previous studies, DCCBs have been studied in perspective of their feasible topologies, models, capability of fault interruption as well as their maturity status. In the project PROMOTioN, a 350 kV 16 kA hybrid circuit breaker provided by ABB has been successfully demonstrated. A single module of a 26.7 kV 10 kA prototype of the Voltage Assisted Resonance Converter (VARC) DCCB from SCiBreak has been demonstrated in 2018. A single module of 80 kV 16 kA prototype of the active current injection mechanical circuit breaker from Mitsubishi Electric has been demonstrated in 2017, whose double-module 160 kV 16 kA prototype has been demonstrated in 2019 and will be fully demonstrated in September 2020. Those demonstrations advanced the TRL of DCCBs and made the DCCBs closer to commercial applications and manufacturing.

Short-circuit current interruption testing of DCCBs is challenging and currently no formal internationally accepted standardisation exists, even though initiatives to create it are underway.

3.1.2.9.3.Full-Bridge Converters

As discussed previously in Section 3.1.2.1, the FB converter has an IGBT on all current paths through the converter (whereas the HB has a freewheeling diode). This has the advantage of giving the ability to control the current even in the event of a HVDC fault, meaning the converter can create the required zero crossing to isolate the fault (depending on the protection philosophy this means that you could completely remove the need for DCCBs and rely on high speed switches). It does introduce increased losses in normal operation.

FB converters can be used for variants of all the protection philosophies but are not an absolute requirement depending on the variant of philosophy used. It is not expected that a philosophy relying purely on FB converters would be used for a DC grid due to the impact on the HVAC grid. However, as DCCBs are both large and costly, it is expected that a complementary combination best utilising the different pros and cons of these technologies may be used in the future.

3.1.2.9.4.Simple Example

To better illustrate the options available, a point-to-point link will be used. If a non-selective approach using HVAC breakers is used (as is the norm to date), for any HVDC fault:

- all power transfer is lost;
- it gives the longest recovery time of the protection philosophy options, and
- it causes high fault current to be drawn from the HVAC systems.

In contrast, if a converter with HVDC fault blocking is adopted (as they did in the German Ultranet) the fault can be interrupted, and the converters can remain in operation acting as large STATCOMS. This can help mitigating the impact of the loss of infeed but it his comes at the price of running a converter with lower efficiency. This in turn can be avoided by having a DCCB at the convertor instead of using a FB convertor. The trade off with that option would be an increased footprint and cost for inclusion of the DCCB.

Within these options, depending on the requirements of the different HVAC networks, it need not be that all convertors and cables have the same protective devices used. So even from this simple example, there are many options with various pros and cons. If this system was extended to three-terminals then there would be further options regarding the selectivity of the protection within the HVDC grid, again with various pros and cons.

3.1.2.10. Topologies for HVDC Connections

In our discussion of conceptual designs, we note 4 distinct forms of integrated HVDC topologies:

- Parallel point-to-point (interconnected on the offshore HVAC side)
  - either based on a monopole design approach, or
  - a bipole approach with a metallic return,
- A multi terminal HVDC approach, where either a single multi-ended HVDC circuit or one supported with DCCB for added resilience forms a “loop” between two onshore connection points with intermediate point(s) of offshore connection along each of those single routes installed,
- Or meshed HVDC grids where interconnection across a variety of routes to the onshore system are achieved via substations made up of 4xDCCB mesh arrangements, or still more extensive switchgear.

These may be compared with point to point HVDC arrangements.

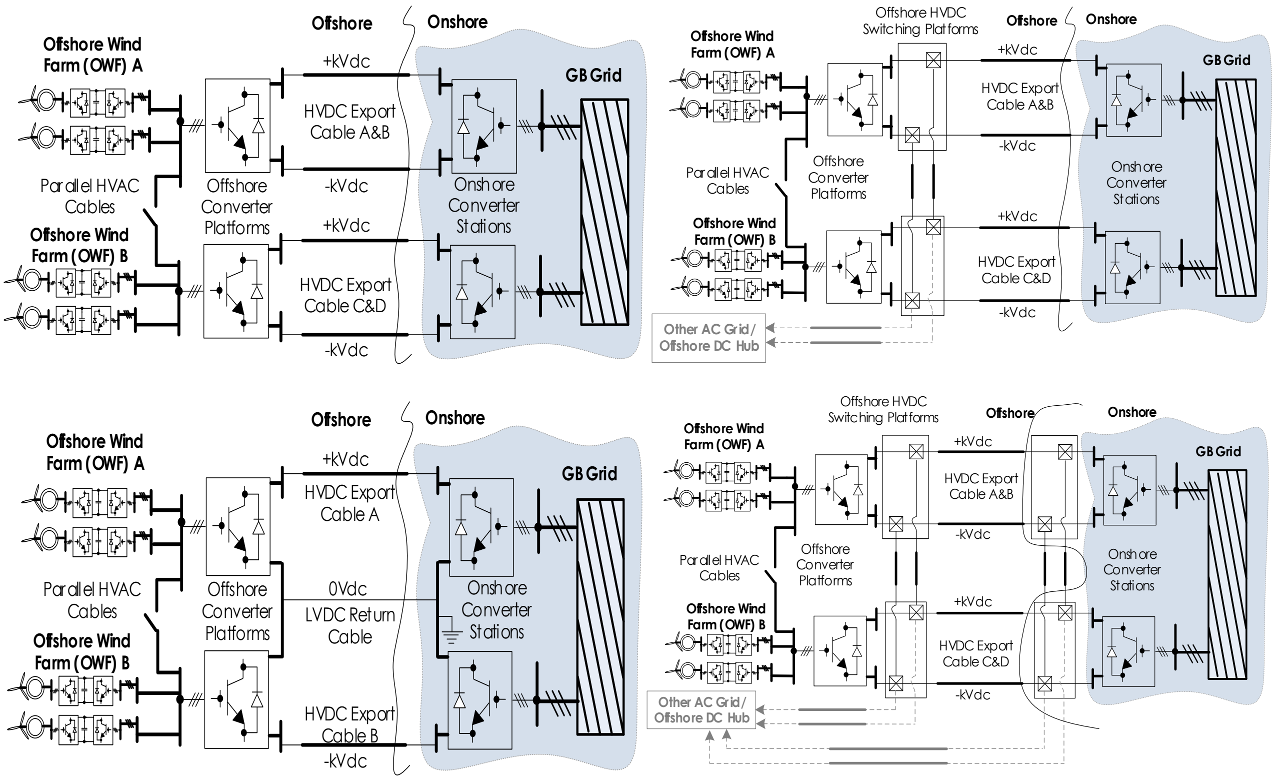


Figure 3-13 Types of offshore integration topologies

The more complex the arrangement the more potential there is for sharing capacity, adding boundary uplift, increasing utilisation and system resilience. The downside is a requirement for more complex controls and additional equipment, and thus space, in the HVDC switchyards. Where on an HVAC system the power will flow depending on the relative impedance of transmission routes, HVDC systems are dominated by the converter controllers. Where there are more controllers there is an increased chance for unwanted interactions and therefore a requirement to have coordination across them. In saying that, meshed HVDC grids will split parallel flows according to relative resistances of the HVDC network's branches with the potential to cause similar bottleneck issues that can be observed on HVAC networks. In all of these HVDC topology options there is a possibility that there will be parallel HVAC links. This is true of the HVDC 'bootstraps' in the UK and grid reinforcements elsewhere. These present integration challenges to co-ordinate the response to system events. But does provide the ability to enhance the operation of the HVAC network using the controllability of the HVDC connection.

There are already existing examples of parallel HVDC connections. Skagerrak, connecting Norway to Denmark, has a total capacity of 1.7 GW combines multiple converters of different technologies. An offshore example would be the Johan Sverdrup HVDC project. Here, two parallel HVDC links are used to power offshore platforms. In both cases a master control is required to coordinate the behaviour of the parallel links.

In Europe, the Caithness-Morray scheme was designed as a radial multiterminal HVDC link and the complete control scheme has been developed and tested. In China they have developed multiple HVDC grids of radial design.

3.1.2.11. List of VSC HVDC Projects

Appendix B and Appendix C have the lists that provide the overview of HVDC project that have been commissioned up to date and the HVDC VSC projects that are in pipeline for future commissioning respectively. Source of this table is from VSC-HVDC Newsletter[21].

[21] M. Barnes, VSC-HVDC Newsletter, 29/05/2020.

3.1.3. Low frequency HVAC offshore connection

LFAC transmission of power from offshore to onshore is one of the alternative ways of transporting the power from the offshore wind farm to the onshore grid and this approach is suggested in many publications. The general overview of a LFAC transmission system is shown in Figure 3-14[22]. In the LFAC system the power generated by the wind turbines' converter is at $16\frac{2}{3}$ Hz at around 3 kV which is then stepped up to 33 kV or 66 kV and then connected the collection grid where is it further stepped to 132 kV to 400 kV transmission voltage level and then transmitted to onshore using HVAC power cable. Onshore a back to back VSC frequency converter or cycle converter is required to convert the $16\frac{2}{3}$ Hz transmission to 50 Hz transmission and synchronise with the 50 Hz onshore grid.

The main advantages of this type of offshore wind energy connections are that it can achieve longer transmission distances compared to 50 Hz AC, yet this system doesn't need an offshore converter which reduces the complexity and cost of such connections.

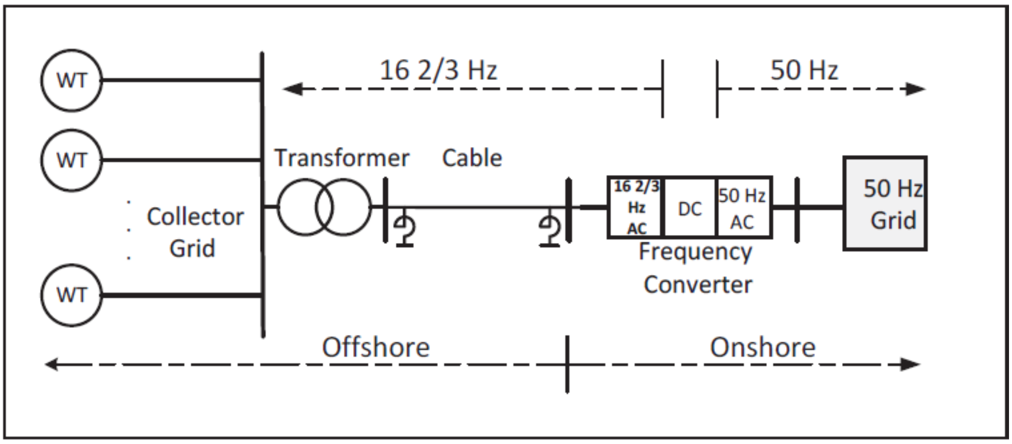


Figure 3-14 Overview of LFAC offshore wind power transmission system

Frequency has a direct impact on the losses in electrical components, cable real power capacity and on the required dimensions of transformers. It thus determines the size and number of required cables, and the weight and therefore cost of the offshore substation transformers and support structure. Moreover, the frequency impacts the arcing time and thus energy dissipated in HVAC switchgear, which needs to be appropriately de-rated for use with frequencies below their design frequency.

3.2. TRL Assessment

3.2.1. TRLs

TRLs are indicators of the maturity levels of particular technologies. The TRL scale was originally developed at NASA for space program. In the European Union, universal usage of TRL scale in EU policy was proposed and consequently implemented in the subsequent EU Horizon 2020 framework program ('H2020'). Assessment by means of TRL is a helpful tool for risk reduction in planning, decision making in investments and commercialisation of project results. For example, technology at TRLs below 7 is not generally considered to be ready for real (pilot or trial) operation.

The TRL scale used for H2020 was adopted and used to assess the readiness levels of technologies in this work. The TRLs defined in H2020 are given in Figure 3-15 as follows:

[22] I. Erlich, "Low frequency AC for offshore wind power transmission - prospects and challenges".

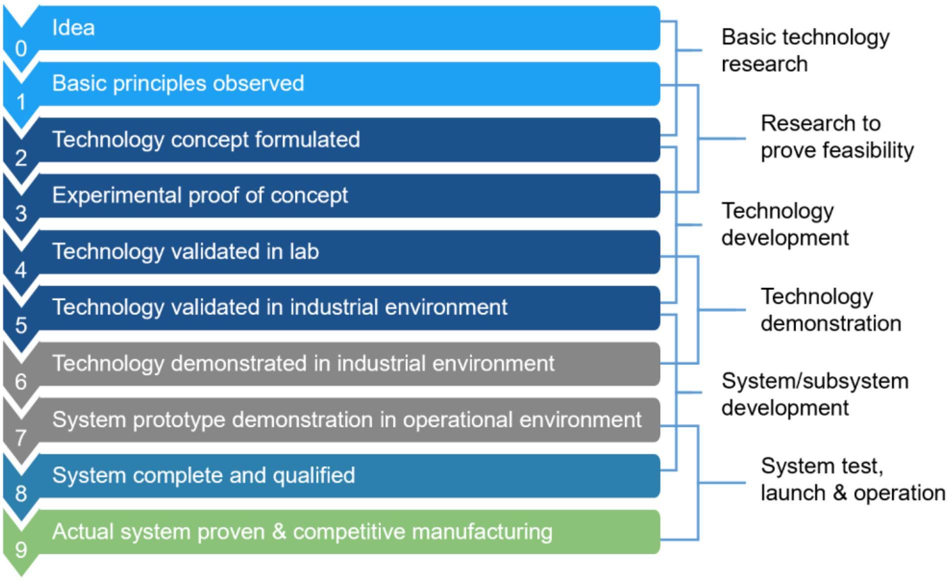


Figure 3-15 TRL scale as defined in H2020

The TRL scale used for H2020 was generic and no sound definition of individual levels has yet been fully explained and exemplified for the electricity T&D sector. In order to adopt the original TRL scale for specific organisation or program, the TRL scale needs to be adapted and customised accordingly. The adapted H2020 TRL scale for assessing the readiness levels of technologies is about product-oriented technologies, including hardware-based and algorithm-based technologies. Hardware-based technologies are primary equipment e.g. DCCBs, development typically starting from circuit analysis and dielectric materials to components to a complete system. Algorithm-based technologies are secondary equipment, e.g. development typically starting from Bode-plots analysis of control systems to software algorithms for stable operation to programming into dedicated hardware platforms.

Thus, non-technological aspects, such as the readiness of regulation and the cost benefit to go to market, are not incorporated. The definitions of TRLs customized are described in the following:

TRL 1 – basic principles observed

Initial scientific research has been conducted. Basic principles are observed. Focus is on analytical studies on fundamental understanding of the principle.

TRL 2 – technology concept formulated

Technology concept is formulated based on the analytical studies. Practical applications of the technology are identified or predicted.

TRL 3 – experimental proof of concept

Technology concept/analytical prediction of the technology is validated by initial laboratory-scale measurements. Modelling/simulation validation in software are considered as the experimental proof of the technology concept.

TRL 4 – technology validated in lab

Individual technology components and their functionalities are tested to work as theory in lab-scale.

TRL 5 – technology validated in relevant environment (industrially relevant environment in the case of key enabling technologies)

Individual technology components and their functionalities are tested to work as theory in industrial environment, where the industrial environment is a representative engineering environment. Independent labs, real-time simulator, and National HVDC Centre etc. are regarded as industrial environment.

TRL 6 – technology demonstrated in relevant environment (industrially relevant environment in the case of key enabling technologies)

Individual technology components are tested with each other as a semi-integrated system. The semi-integrated system with its functionalities is tested and confirmed to work as expected in an industrial environment using the real system input.

TRL 7 – system prototype demonstration in operational environment

The prototype of full-scale integrated system with its functionalities are tested and confirmed to work as expected in an operational environment (on-site environment e.g. outside manufacturer laboratory) using the real system input.

TRL 8 – system complete and qualified

Integrated system with its functionalities is proven to work as expected against industrial norms and standards. The manufacturing process is considered as preliminary.

TRL 9 – actual system proven in operational environment (competitive manufacturing in the case of key enabling technologies; or in space)

Actual operating system as a developed technology with its full functionalities is proven to work under full range of operating conditions. The developed technology is ready for commercial production and delivery. The manufacturing process is optimised.

In the adapted TRL scale, at lower levels of TRL 1-3, only technology concepts are investigated with analytical studies or preliminary lab-scale measurements. No physical realization has yet been started. The initiation of algorithm development also starts at these stages. When referring a technology to a level from TRL 4-9, physical realizations are implemented: either algorithms are implemented and stressed functionally, or equipment hardware is implemented and stressed physically. At TRL 4-5, technology is limited to individual components. When moving to TRL 6, technology refers to a semi-integrated system with individual components working together with each other. At higher levels of TRL 7-9, technology refers to the completely integrated system with full functionality. At TRL 7, technology being considered is still a system prototype, whose manufacturing process is operational. When technology is assessed as TRL 8-9, the actual system is considered, and the manufacturing process is fully established and optimized. Such scales and development stages of technology defined in adapted TRL H2020 are summarized in Table 3-1. More detailed development progresses of algorithm and hardware based technologies along the TRL scale are described in Figure 3-16.

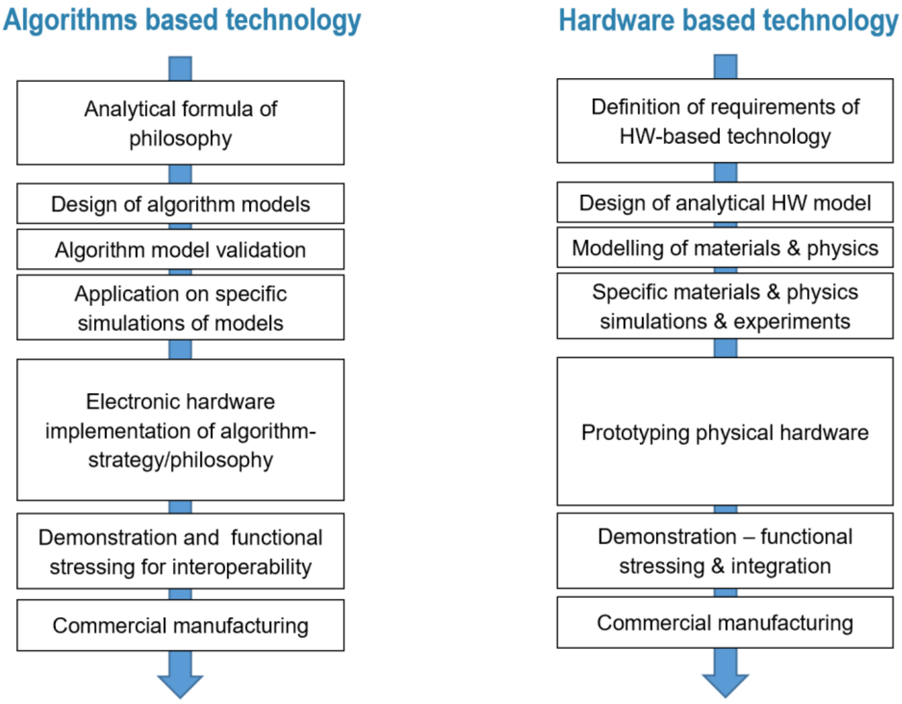


Figure 3-16 Algorithm- and hardware-based technologies along the TRL scale

Table 3-1 Technology scales and development stages corresponding to adapted TRL H2020

TRL	Technology scales	Development stages
1	Analytical research	Principle
2		Concept
3	Lab measurement	Concept
4	Technology components and/or breadboard	Algorithms implemented and functionally stressed
5		
6	Low-fidelity, semi-integrated system of technology components	Or
7, 8, 9	System prototype, high-fidelity, Integrated system of technology components with full functionality. Manufacturing process is operational.	Equipment hardware implemented and physically stressed

3.2.2. Methodology

During the TRL assessment, the HVDC technologies were reviewed based on either their voltages/ratings or their development steps which enable the final commercial availability of the technology. The adapted TRL scale was then applied, consistently and coherently, to assess the maturity status of the technology at each voltage/rating or at each development step. The TRL assessment results are presented in the perspective of individual technology based on each voltage/rating or along the development steps. By this way, the readiness level of a certain technology is clarified. Moreover, it is also clear which level steps still need to be taken before the technology can be considered ready for deployment.

3.2.3. TRL of HVDC technologies

In this section, TRL scale is applied to assess the industrial maturity status of the key HVDC primary technologies demanded for offshore grids, which are listed as follow:

1. HVDC cables
2. HVDC converters
3. DCCBs
4. HVDC GIS

The TRLs of HVDC cables and HVDC converters are assessed based on the current state of the art of these technologies, which were collected by DNV GL from an internally available information database on the market and information from questionnaires circulated to the main manufacturers.

The TRLs of DCCBs and HVDC GIS system are assessed based on the experience gained in the project PROMOTioN, which investigated and demonstrated the technologies.

3.2.3.1. HVDC cables

In principle, VSC-HVDC converters have no technological limit or barrier for higher voltages and higher outputs, as converter module can be stacked in series. An important consideration is that, the current carrying capacity of the semiconductor elements in the converter is maintained and not exceeded. The bottleneck for the rated power of the VSC-HVDC connection is usually represented by the nominal current and the nominal voltage of the cable, especially with XLPE-insulated energy cables.

The currently planned and constructed submarine HVDC cable projects worldwide are carried out with nominal voltages also greater than 320 kV (more specifically 525 kV). HVDC cables with these two voltage levels are widely used nowadays and appear promising for more applications in the further. They are set up by the current industrial standards to be requested by the customers and supplied by the manufacturers. On the other hand, there are also HVDC cables available with other voltage levels, e.g. 350 kV, 400 kV and 640 kV. To provide a comprehensive overview of the available options, HVDC cables with those voltage levels are also assessed here, including 320 and 525 KV. Moreover, only the DC submarine cables will be discussed and assessed. The TRLs assessed for the respective voltage levels of the HVDC submarine cables are shown as follow in Figure 3-17.

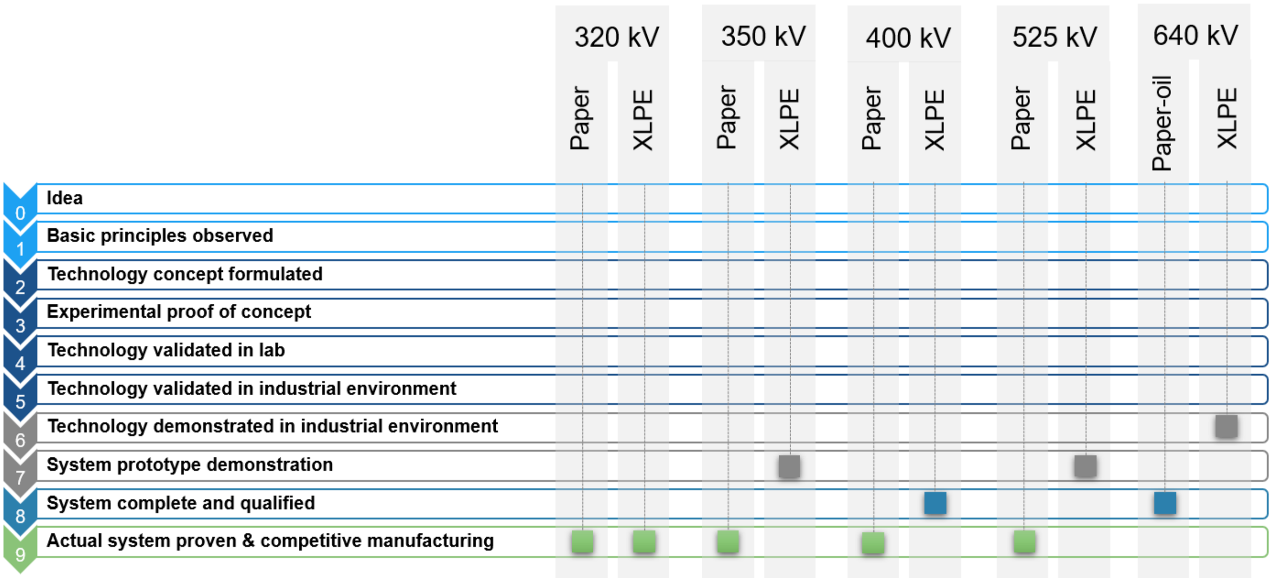


Figure 3-17 TRL of HVDC cables

A technology has reached maturity and full operational readiness if the prequalification tests have been successfully passed and if the system has been in continuous operation for several years, approximately 5 years on average. XLPE-insulated HVDC cables have just completed this period in operation, while paper-insulated HVDC cables can look back on significantly longer years of operation, which means two decades and more since the commissioning of the first HVDC cable connections on land and in the sea as submarine cable design. Since the operating experience with XLPE or paper-insulated submarine cables is not identical, different ratings were chosen for the submarine cable technology.

Paper insulated DC cables in all considered voltage levels

Paper mass cables are available for all DC applications up to 525 kV DC, whereas paper-oil cables (FF - fluid filled) are also available at 640 kV DC. Paper-insulated HVDC submarine cables of higher voltages (paper mass cable up to 640 kV and paper-oil cable up to 525 kV), which are available for all HVDC applications, are classified as TRL 9, since they have been installed and are in operation in several projects and quite some operational experience has been gained. For example, the 525 kV paper-insulated cables used in project Skagerrak are in their 6th year of operation.

XLPE insulated DC cables in all considered voltage levels

XLPE HVDC cables of 320 kV have been used for submarine connections for several decades, with the first generation now being out of its warranty. With this long-term operation experience, 320 kV XLPE insulated HVDC cables reach a TRL of 9. HVDC submarine cables with a voltage of 400 kV are available on the market. 400 kV HVDC cables with 1000 MW transmission capacity has been installed and in operation in Nemo interconnector, which was commissioned in 2019. TRL 8 is thus assessed for the 400 kV DC XLPE insulated cables, since they are operated for only one year and more operational experience is expected. Individual manufacturers already offer cables with 525 kV DC and 640 kV DC. TRL 7 is assessed for 525 kV XLPE insulated HVDC cables, since they have successfully passed the performance qualification and type tests for German corridor projects. TRL 6 is assessed for XLPE-insulated DC cables of higher voltage levels as 640 kV for marine use, since these are currently, if at all, in the trial and qualification phase.

3.2.3.2. Converters

Since LCC converters are incompatible with offshore wind connection, here only VSC converters are considered. HVDC VSC converter systems with 900 MW rating have become the industrial reference, driven by the similar size of the offshore wind farms. The solutions for all requested voltage levels and applications, (320, 350, 400 and 525 kV converters for offshore installation) are commercially available on the market. Similar to HVDC cables, DC converters with 320 kV and 525 kV are more requested and applied, whereas converters with all the voltage levels are assessed here to give an overall overview. Figure 3-18 shows the TRL assessment of HVDC converters based on the voltage level and capacity. Appendix B gives a list of existing VSC HVDC projects globally.

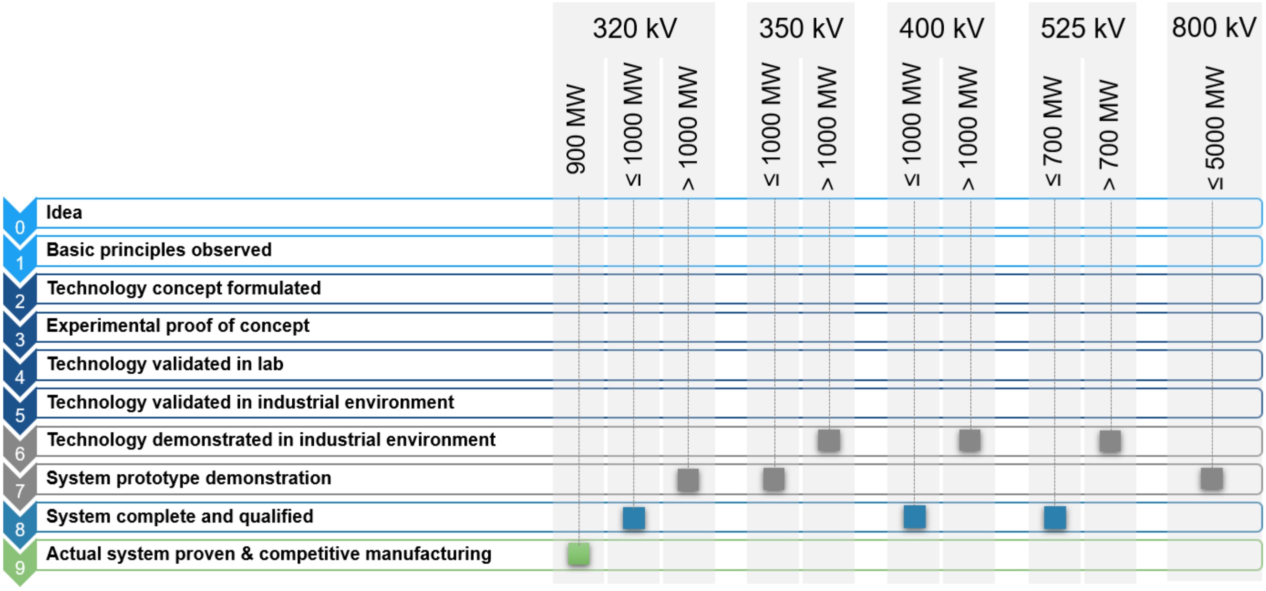


Figure 3-18 TRL of HVDC VSC converters

320 kV DC VSC converters

320 kV DC VSC converter technology with 900 MW is assessed as TRL 9 because a large number of systems with this transmission capacity have already been set up and are successfully in continuous operation. The "+/- 320 kV DC 900 MW" VSC connection is currently the standard solution for offshore wind farm integration. Converter substations at +/- 320 kV DC, have extended operating proof, contrary to subsea HVDC cable experience. The technology is assessed as TRL 8 for outputs up to 1000 MW, since projects of this performance class already exist and the fundamental and required power modules for this transmission capacity with the required current carrying capacities for the VSC converter technology are available on the market. Due to the lack of project experience, 320 kV DC VSC converter technology with more than 1000 MW is assessed as TRL 7.

350 kV DC VSC converters

Back-to-back converter solutions with this voltage level have already been installed in China, but with a transmission power lower than 1200 MW. For offshore, these solutions do not yet exist and are therefore classified as TRL 6 or TRL 7 for limited services.

400 kV DC VSC converters

Individual interconnectors using 400 kV VSC converters have been in operation in the NEMO project for one year with a transmission power of 1000 MW. Thus, a TRL 8 is given to 400 kV VSC converters. Offshore solution for larger capacities is assessed as TRL 6 for limited services.

525 kV DC VSC converters

In Europe, the Skagerrak 4 link at 500 kV and 700 MW has been in successful operation for several years and 525 kV interconnectors (NordLink) are in commissioning and several more in development (Viking and NSL). A TRL 8 is hereby assessed to 525 kV VSC converters with capacity less than 700 MW. And the absence of planned projects leads to a TRL 6 for outputs greater than 700 MW up to the maximum output.

800 kV DC VSC converters

Interconnectors with this voltage level and this transmission power are currently being built in China. The offshore solution is classified as TRL 6, as there are currently no plans or construction activities known in this power and voltage class.

3.2.3.3. HVDC circuit breakers

There are already different manufacturers providing DCCBs to the market. For example, GE has published test results on DCCBs and the ABB group, SciBreak and Mitsubishi are all developing DCCBs, which have been investigated in project PROMOTioN. PROMOTioN project sets out to develop model, analyse and demonstrate the DCCB technologies. The final demonstrations focus on the full power HVDC short-circuit current interruption testing of three different types of DCCBs from three suppliers. An overview of the three types of DCCBs provided by three manufactures and their demonstration status are given in Figure 3-19.

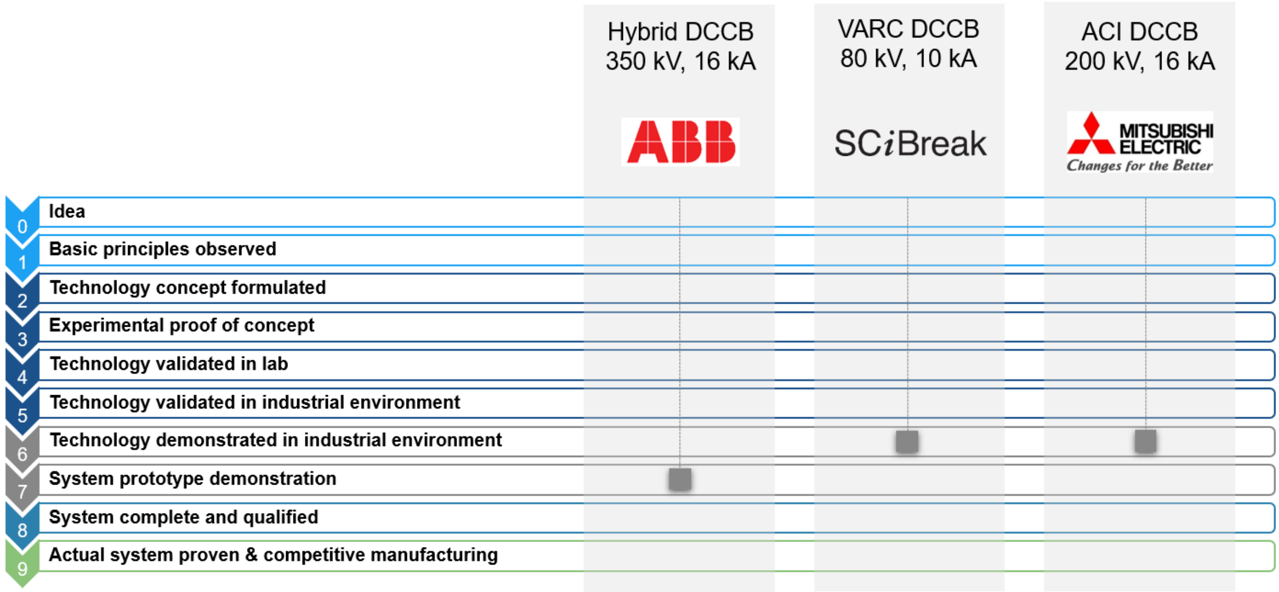


Figure 3-19 TRL of three types of DCCB demonstrated in PROMOTioN

DCCB technology as a whole has reached TRL 7 in Europe. The available DCCBs are technically ready for application in real projects, but have not yet been deployed practically. Considering the different DCCB types, the 350 kV 16 kA hybrid DCCB provided by ABB has been successfully demonstrated in full-scale. However, since it has not yet been applied in operation, this hybrid CCB was assessed as being at TRL 7. The Voltage Assisted Resonance Converter ('VARC') DCCB provided by SCiBreak and the active current injection ('ACI') DCCB provided by Mitsubishi will have their final demonstrations later 2020. Currently each of these has been assessed as being at TRL 6. In Figure 3-20, the TRL of the ABB hybrid DCCB is given as an example, that was analysed from TRL 1 as part of the PROMOTioN project.

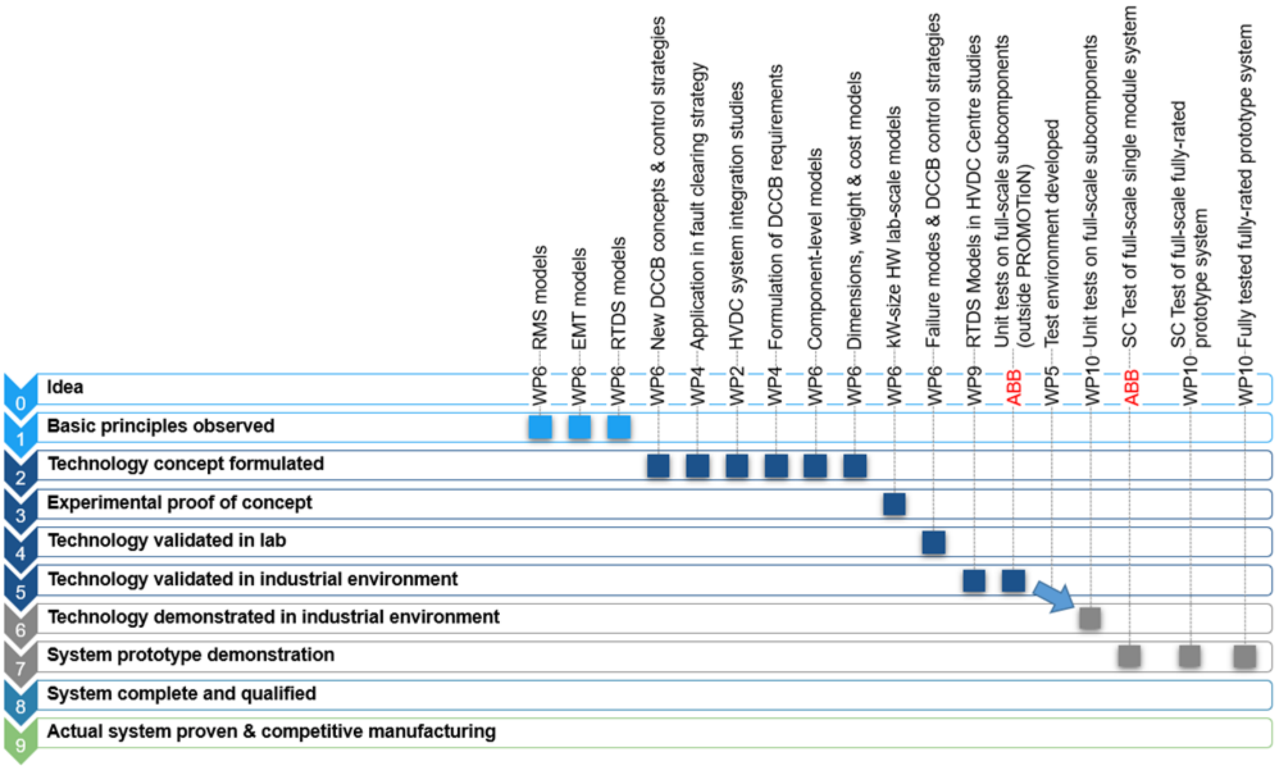


Figure 3-20 TRL of hybrid DCCB demonstrated in PROMOTioN

New DCCB concept and control strategies were formulated in WP6 in order to improve its performance in the DC transmission grid. The performance of the DCCB with different fault clearing strategies was investigated in WP4, upon which, the requirements of DCCB were formulated. In WP2, the integration of DCCBs in HVDC grids was studied by analysing interactions between DCCBs and converter and system control. Detailed component level models for hybrid, mechanical and VARC DCCB were then developed in WP6, which also led to possible new designs with beneficial dimensions, weight and cost models. In these steps, concepts in several aspects of DCCB have been formulated analytically, which justifies progress up to TRL 2.

Small-scale (kW-size) hardware demonstrators of hybrid and mechanical DCCBs were designed and implemented in the lab in WP6, which has been proven to work through experiments. This is viewed as TRL 3.

In the next immediate step, the failure modes and DCCB control strategies were tested by using the kW-size hardware demonstrator in the lab, which is assessed as TRL 4.

RTD simulator models of the DCCBs were developed for testing under different fault scenarios as part of WP9 in the national HVDC centre, which is considered as an industrial environment. Hereby, this step is viewed to reach TRL 5. In parallel, ABB and Mitsubishi performed unit tests on full-scale subcomponents in their own lab, which is assessed as TRL 5. However, ABB's unit tests are beyond the scope of PROMOTioN. In spite presenting it in the TRL assessment result, this step is shown in red colour for notice.

In PROMOTioN, the test environment for testing DCCB, including the test requirements, test procedures and test circuits, were developed in WP5. However, this is considered as an enabler to the development of the DCCB, instead of an actual development step. Therefore, an arrow is used to present the development of the test environment in the TRL assessment result, rather than the achievement of an actual TRL advance.

The unit tests on full-scale subcomponents were demonstrated again in KEMA lab, which is considered as an industrial environment. This makes this step to reach TRL 6.

In the next step, the short circuit tests were performed on full-scale single module system in ABB lab and on fully rated prototype system in KEMA lab respectively, which lead to a TRL 7 for both steps.

In the last step, the DC short-circuit current breaking capability of a fully rated and fully integrated prototype of a 350 kV hybrid DCCB from ABB was demonstrated successfully at a system level, which is justifies an advance to TRL 7. The test object was manufactured using regular production processes and implemented using an existing fully qualified valve support structure design. According to ABB, full-scale operational, dielectric and endurance tests were done internally. However, due to the lack of standards and qualification process, the demonstrated hybrid DCCB is not going to be qualified against norms or standards. The next step for the demonstrated hybrid DCCB is to get ready to go for commercialization and competitive manufacturing, which is TRL 9. Therefore, the demonstrated hybrid DCCB is assessed as TRL 8 as current status.

The industry practice for technology readiness and acceptance in China is clearly different than that in EU. In the world's first HVDC grid - Zhangbei HVDC project, hybrid DCCBs from different suppliers have been installed in the four converter stations in the transmission ring. In two stations, the DCCBs have been partially commissioned. In the other two converter stations, the commissioning has just begun. Before installation, all the DCCBs have been fully type tested in either independent laboratories, or at manufacturers' laboratories where witness testing by a third party is required. The DCCBs being successfully type tested are then accepted by the customers. In such sense, the readiness level of the DCCB technology in China is viewed as mature and manufacturing competitive, and therefore is considered as TRL 9.

3.2.3.4. HVDC GIS

GIS for use in HVDC transmission has been under development by several manufacturers for several years. Thus, the maturity level of HVDC GIS is relatively high. However, there is no international standard for the specification requirements nor test procedure for HVDC GIS. Project PROMOTioN investigated HVDC GIS and demonstrated it with a long-term test, which promoted the HVDC GIS to an advanced status. Such status can be considered to represent the status of the HVDC GIS. The maturity levels of HVDC GIS are assessed via applying TRL scale in two aspects:

- HVDC GIS system with SF_6
- HVDC GIS system with SF_6 alternative

The development of HVDC GIS system with SF_6 and the corresponding TRL assessment results are given in Figure 3-21.

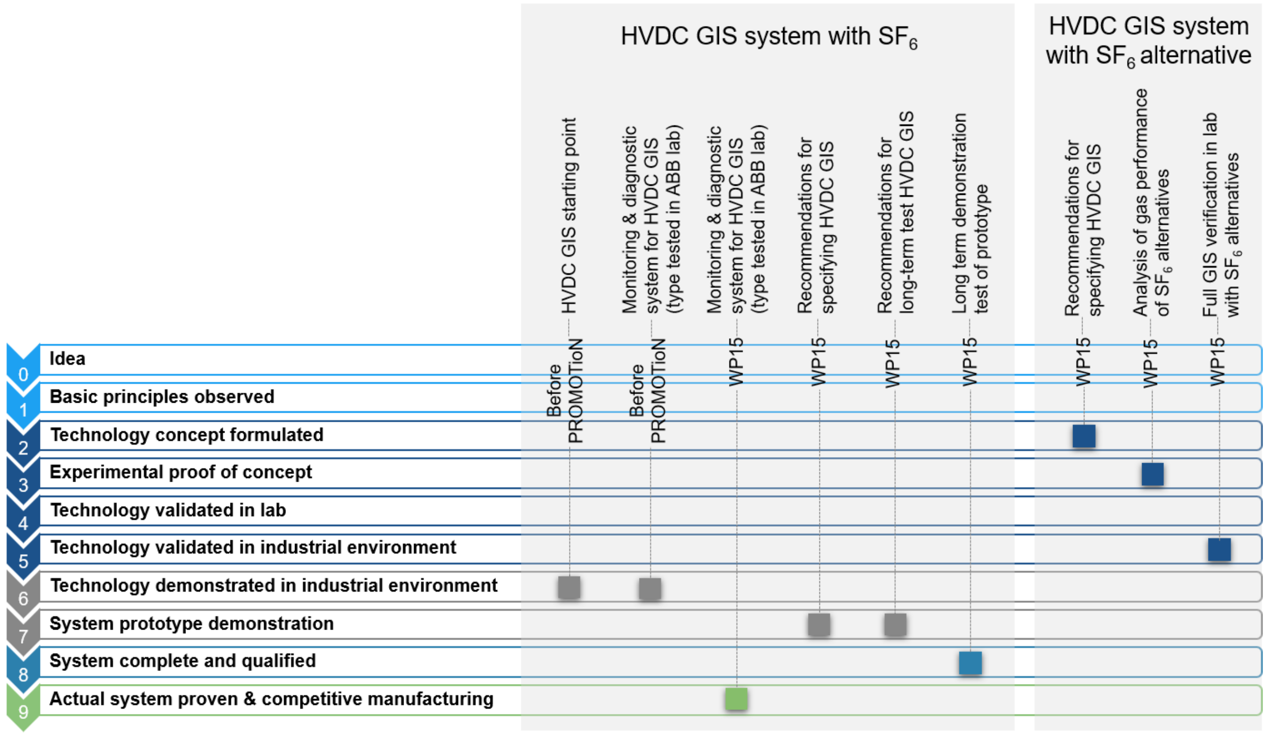


Figure 3-21 TRL of HVDC GIS demonstrated in PROMOTioN

For HVDC GIS system with SF_6, before PROMOTioN started, the HVDC GIS system and its monitoring and diagnostic system have already achieved TRL 6. In PROMOTioN, the monitoring and diagnostic system has been promoted to TRL 9. The long-term demonstration of prototype system advanced the readiness level to TRL 8. This is further justified by one installation of HVDC GIS in Japan (Honshu-Hokkaido) and the recent award for offshore HVDC GIS (Dolwin5). For HVDC GIS system with SF_6 alternative, the full HVDC GIS verification in the lab with SF_6 alternative enables the readiness level to TRL 5.

3.2.4. TRL of HVAC technologies

HVAC technologies are already in use for offshore wind farm connections, a list of these connected in the UK is included in Appendix A. The maturity status of HVAC technologies depends on the distance to shore. The TRLs assessed based on the topologies are shown in Figure 3-22.

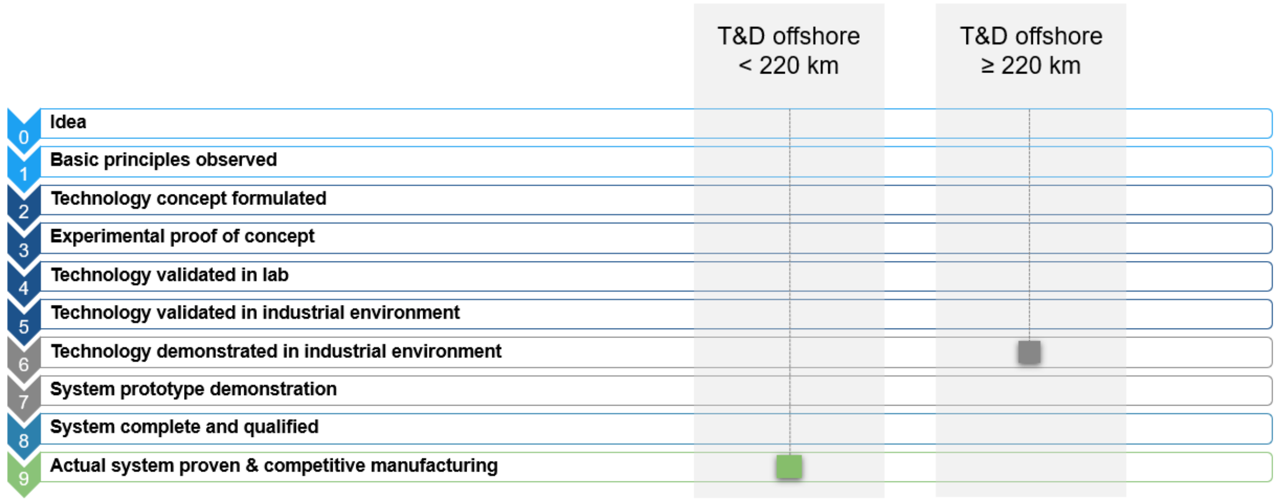


Figure 3-22 TRL of HVAC technologies

For offshore HVAC application, there is little difference among topologies (point-to-point, radial and meshed topologies) with respect to TRL. HVAC circuit breakers and fault clearing are mature technologies, consequently all of the three topologies should have the similar level of TRL.

The critical change happens with increasing distance from the shore. With near shore application (< 220 km), it is mature technology to connect using HVAC. With far offshore applications (≥ 220 km), the capacitive charging current will be significant as compared with the thermal capacity and sophisticated reactive compensation schemes are needed. In addition, long cable often comes together with risk of harmonic resonance, control interaction, etc. For far offshore grid applications, HVAC solution is still an immature technology, when assessed against TRL criteria, hence viewed as TRL 6.

3.2.5. TRL of LFAC technology

Currently, the LFAC technology using $16\frac{2}{3}$ Hz low frequency is mainly applied in railway systems, where most of the operating experience has been gained. On the contrary, LFAC technology used for offshore wind connections is still under development, where there is a need to ride through onshore faults, provide reactive power support, provide frequency support, energise wind farms and support their stabilisation. As shown in Figure 3-23, TRL for LFAC technology in offshore applications is assessed as TRL 3.

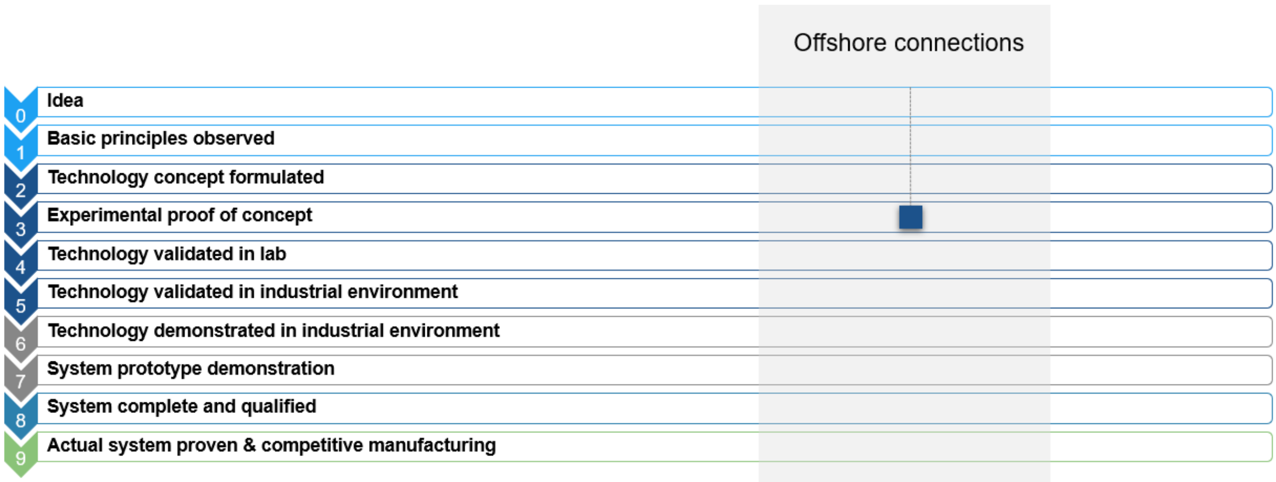


Figure 3-23 TRL of LFAC technology for offshore connections

3.2.6. Considerations (Barriers)

The TRL assessment results present the current maturity status of the key technologies for offshore wind connections, which from another perspective, reveal the further development needed before those technologies become commercially competitive. Therefore, it is important to identify the barriers existing in the development of these key technologies.

3.2.6.1. HVDC cables

HVDC cables for offshore applications with higher voltage levels (320 kV – 525 kV) are technically mature, as they are commercially available and have been installed in several projects. However, there are still barriers to be concerned about such as:

- limited operation experience of offshore;
- maintenance / repair in case of damages or failures;
- temperature rise needs to be limited to protect marine life, and
- risk of electro-osmoses in the vicinity of earthing electrodes.

3.2.6.2. HVDC converters

HVDC converters for offshore connections have no voltage or power limitations (320 kV – 525 kV) for offshore applications. The barriers concerned are related to interoperability between different:

- converter topologies (converter configurations and controls)
- vendors' technologies (proprietary / patented techniques)

3.2.6.3. HVDC circuit breakers

DCCBs are an inherent requirement for meshed designs (T7 conceptual design, see Table 4-1). Without these devices either coupling between HVDC would need to occur at HVAC, requiring associated additional HVDC convertors per circuit to achieve this, or solutions without coupling altogether would be required. In the former situation the maximum HVAC busbar capability (currently 1200 MW at 220 kV) would present an offshore limitation to the effectiveness of any coupling. An alternative to DCCB is available if FB convertor designs are used on and offshore, allowing DC fault current interruption by convertor, and an isolation and restore scheme to be utilised across the combined system elements. Such schemes however both expensive in nature (double-scale convertors on and offshore, and slower in fault clearance and restoration of HVDC circuits (at least 250 ms in comparison to c. 30 ms)

There is no current example of a European DCCB installation onshore or offshore. The EU PROMOTioN project, as part of the H2020 research initiative has however defined specification and testing standards for such DCCBs to be applied to European markets, and tested example circuit breakers (up to 320 kV) to this specification .[23]

Internationally, whilst DCCB installation at offshore locations has yet to occur, onshore DCCB installation has. One such examples the 500 kV meshed HVDC grid Zhangbei project.[24]. The project commissioned in 2019, and whilst limited operational experience is available as yet, no reports of issues with DCCB have been received. With respect to that project, papers are available which give context to the project concept and its testing and specification.[25]

A more general discussion of DCCB technology may be found elsewhere in literature.[26]

There are still barriers to be overcome:

- Limited specifications, operating guidelines, international standards
- Limited experience for transmission power rating utilization

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[23] https://www.promotion-offshore.net/fileadmin/PDFs/D10.8_Initiation_of_Standardization_activities_for_HVDC_circuit_breaker_design__testing_and_application.pdf

[24] https://www.hitachiabb-powergrids.com/references/hvdc/zhangbei

[25] G. Tang, G. Wang, Z. He, H. Pang, X. Zhou, Y. Shan and Q. Li, "Research on Key Technology and Equipment for Zhangbei 500 kV DC Grid", 2018 Int. Pow. Electronics Conf. (IPEC-Niigata 2018 -ECCE Asia), Niigata, Japan, pp 2343- 235, 2018 https://www.researchgate.net/publication/328984243_Research_on_Key_Technology_and_Equipment_for_Zhangbei_500kV_DC_Grid; and G. Tang, Z. He, H. Pang, Y. Wu, J. Yang, X. Zhou and M. Kong, "Characteristics of system and parameter design on key equipment for Zhangbei DC grid", CIGRE Conf., paper B4-121, 2018, https://e-cigre.org/publication/SESSION2018-2018-cigre-session

[26] https://www.researchgate.net/publication/338137332_HVDC_Circuit_Breakers_for_HVDC_Grids

3.2.6.4. HVDC GIS systems

Whilst GIS systems with SF_6 are technically mature for applications in HVDC, the technology with SF_6 alternative is not yet industrially mature (nor widely implemented) which is considered to be a barrier.

3.2.6.5. HVAC technologies

HVAC technologies have been well applied in offshore applications with certain limitations, which are considered as:

- limited circuit length;
- the physical footprint on the seabed of the number of HVAC cables in the connections to onshore, and
- requirements for HVAC transmission system reinforcement at the onshore infeed point, e.g. reactive compensation devices

3.2.6.6. LFAC technology

LFAC technology has been applied in railway systems, but is not a proven solution for offshore transmission and distribution. The barriers identified are:

- no standards;
- no prototype/demonstrator, and
- no market pull (no incentive for the development).

Increase of TRL levels into the future, for all the technologies assessed, would be a result of both the market pull and supplier development. Market pull will result from planned projects with higher wind farm capacities, e.g. 1200 MW. Supplier development would be driven by differentiation for competitiveness. The further outlook of TRL levels will be more completely elaborated in section 5 of this report on overcoming technology barriers.

3.3. Conclusions

There are many technologies available that can be used to connect offshore wind farms to shore. There are however differences in the relative maturity of these technologies as well as significant innovation that is ongoing, so the availability and readiness of options is continually changing. For the volumes and timescales of new offshore windfarms under consideration for this project, options focusing on HVAC and HVDC are the most relevant for consideration for the conceptual network design development work.

HVAC is the most mature technology however the inherent limits of this technology (although being pushed by innovation) are starting to limit the applicability of this option. There is little opportunity to use this technology to develop a coordinated offshore grid that is suited to future requirements.

For HVDC there are aspects of the technology which are mature and suitable for use to meet the short-term requirements. Within HVDC there are many variants of this technology which have different capabilities and levels of technology readiness. HVDC network designs can be developed that offer a capability to be extended which could be attractive for a more modular approach to the development of a coordinated offshore network. However, several barriers have been identified for this type of modular approach, which are: integration of the different network elements; facilitating the incremental development of the offshore grid; a lack of standardisation; and proven interoperability at these scales. These require technical and process frameworks.

Other technologies mentioned, such as LFAC and DRU, are considered to be too immature to be considered for the developments required by 2030.

4. CONCEPTUAL DESIGNS RELEVANT FOR OFFSHORE DESIGN WITHIN GB AND ITS OFFSHORE WATERS

Eight conceptual network design option topologies were identified and developed as part of this assessment. These included examples that are an evolution of the offshore transmission systems we have currently in GB, as well as designs that are not yet in operation anywhere in the world such as shared multi-purpose offshore hubs. This section provides a summary of the:

- range of conceptual offshore network design topologies for wind farm transmission connections that were identified;
- KPIs identified for and used as part of the offshore coordination assessment;
- qualitative comparison of each option's performance against different KPIs, and
- conceptual design topologies identified as suitable for use as building blocks as part of an integrated offshore network solution.

4.1. Conceptual Network Design Topologies Identified

One radial HVAC topology (T1) and seven (7) high-level conceptual network design topologies (T1A-T7) were identified for incremental development of offshore transmission solutions in GB. Each of the conceptual design topologies can be built sequentially and in a staged manner to meet the growth of offshore wind capacities across different regions, provided that basic technical parameters are coordinated for expandability and compatibility

4.1.1. Design 1 (T1): Radial High Voltage Alternating Current (HVAC)

Figure 4-1 shows a radial HVAC 50 Hz building block design, which illustrates the business as usual approach that has been used to date. The benefits and limitations (e.g. coastal impact, space required to meet levels of wind for net zero targets) of this single radial approach are well understood (meaning each separate wind farm would have one connection to the onshore network). Design option T1 was used for comparison purposes for our assessment of other possible design options identified. This will help us understand whether there are sufficient drivers for moving from the current approach and we will use this approach as the foundation for associated cost-benefit-analysis.

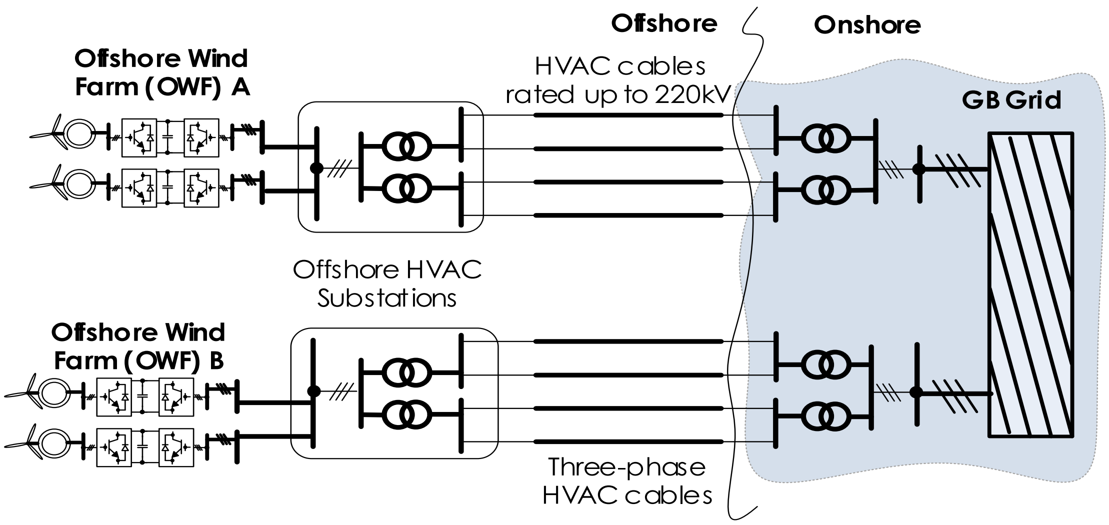


Figure 4-1 Radial HVAC 50Hz building block

4.1.2. Design 1A (T1A): More Integrated HVAC (50Hz)

Within the maximum capability of HVAC technology in GB, design option T1A (illustrated in Figure 4-2) takes account of the maximum scale of connections and maximum distances that could be connected. This option has the flexibility to gather power from multiple wind farms, distribute power across parallel routes and connect multiple wind farm projects. Design option T1A is highly capable and to date a technology that has been selected by many developers to connect offshore wind farms to the GB transmission system. In terms of building block suitability, this option is limited in terms of size of power that can be transported and circuit length, although can be enhanced with booster stations at the cable ends and/or midpoint to allow improved voltage regulation and facilitate transmission at distances up to 200 km.

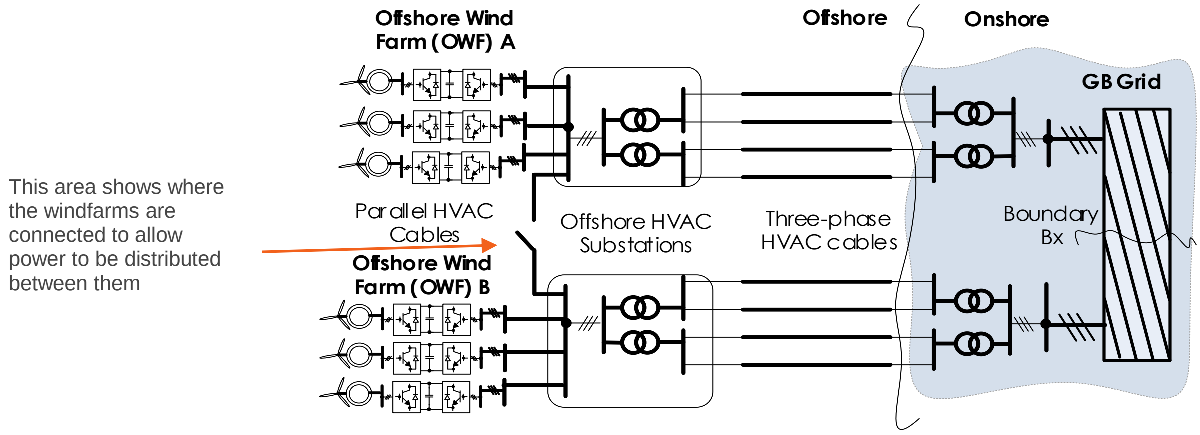


Figure 4-2 More Integrated HVAC Design

4.1.3. Design 2 (T2): Lower frequency High Voltage Alternating Current

This option (seen in Figure 4-3) using innovative low frequency transmission approaches would be expected to allow HVAC transmission distances to be extended further enabling power travel further than in the first two options. In terms of building block suitability, this option is expected to be limited in terms of capacity (albeit across longer distances) and the technology is not yet sufficiently mature for GB deployment.

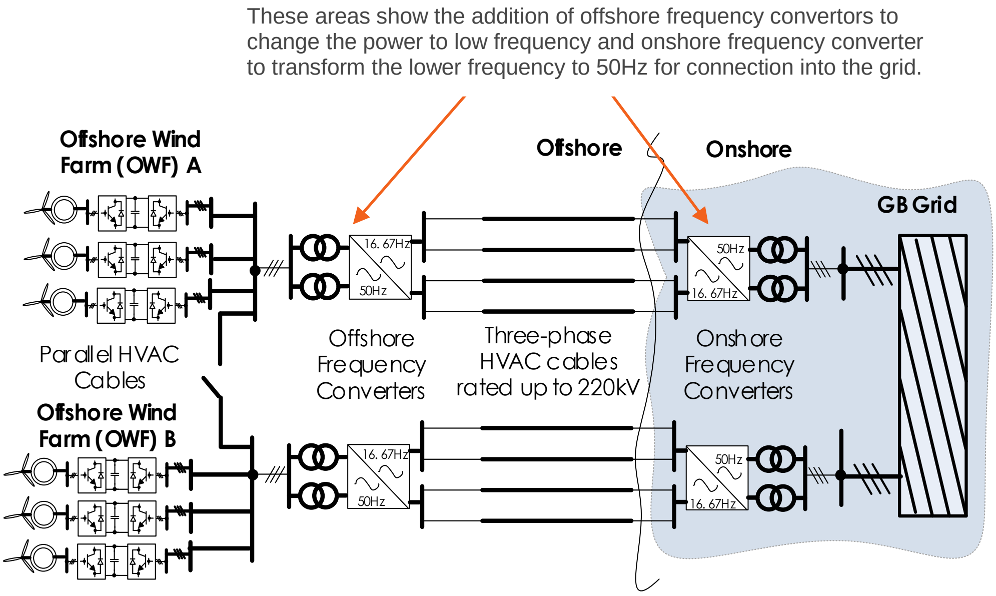


Figure 4-3 Lower Frequency HVAC Design

4.1.4. Design 3 (T3): Extended HVAC with parallel High Voltage Direct Current (HVDC)

This design combines HVAC (designs 1 or 1A) technology used today with an integrated HVDC connection that connects to a different location onshore, as illustrated in Figure 4-4. This design would allow for the extension of a current offshore development (or nearby development) where the existing infrastructure would not be adequate to accommodate the extension. In terms of building block suitability, this design has the ability to extend out into more distant offshore connections from the shore, but could also provide higher capacity. There is flexibility regarding where the HVDC circuit can land and connect onshore due to fewer restrictions on the distance, but the overall connection offshore distances would still be limited due to limitations with the existing HVAC connection.

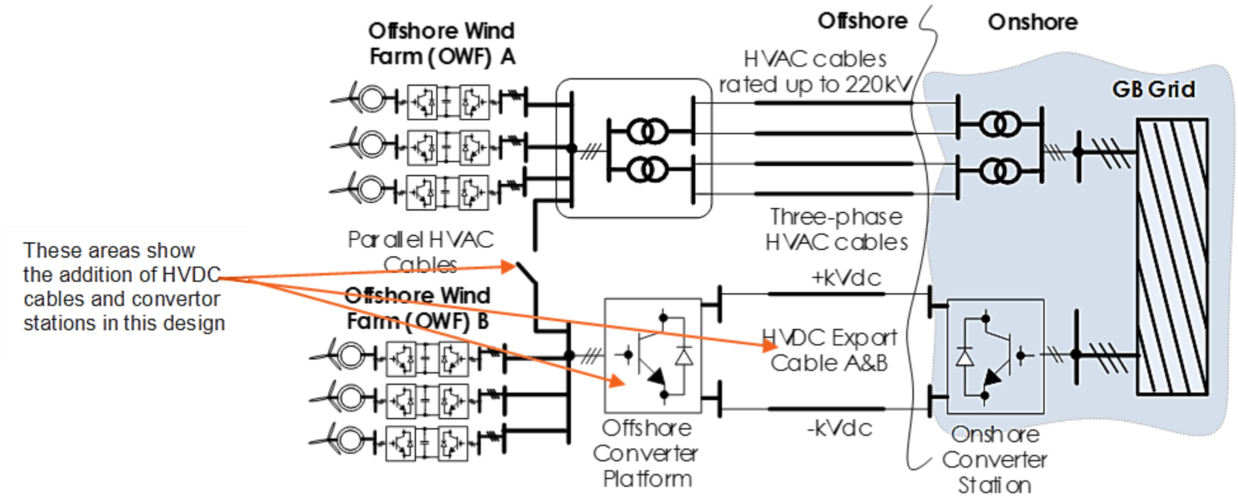


Figure 4-4 Extended HVAC with parallel HVDC Design

4.1.5. Design 4 (T4): High Voltage Direct Current connections offshore

This design is similar to the German approach and is illustrated in Figure 4-5. This design option could increase the scale of installed wind farm capacity that can be connected offshore and distance from shore are not restricted due to technology capability limits. In terms of building block suitability, the T4 design could either be deployed in individual point to point arrangements or with an option to interconnect between offshore HVDC substations using traditional HVDC technology. This design option is very flexible and could be landed in principle anywhere across GB.

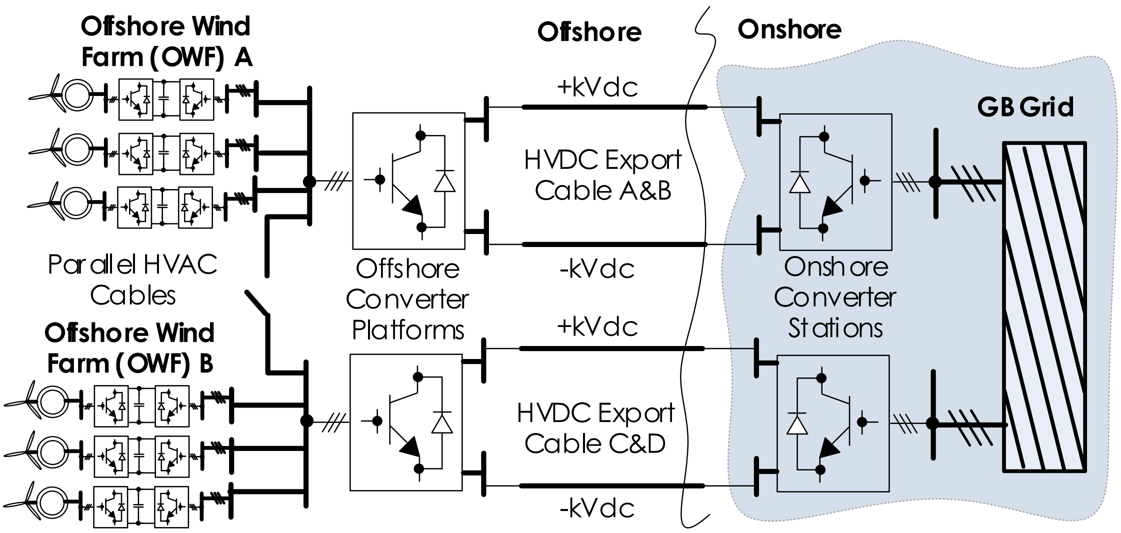


Figure 4-5 HVDC with offshore HVAC interlinks

4.1.6. Design 5 (T5): Bipole High Voltage Direct Current technology

Using a more innovative approach and learning from other experiences, this design option uses different configuration (bipole) HVDC technology. This option requires less offshore and onshore cabling for an equivalent power capacity than any other conceptual network design option considered. A lower total asset volume may result in lower costs (subject to a detailed cost-benefit analysis). In terms of building block suitability, the T5 design provides more flexibility for offshore connections including the location of onshore landing points and can facilitate reliable operation during faults using HVAC and LVDC switching arrangements (does not rely on DCCBs).

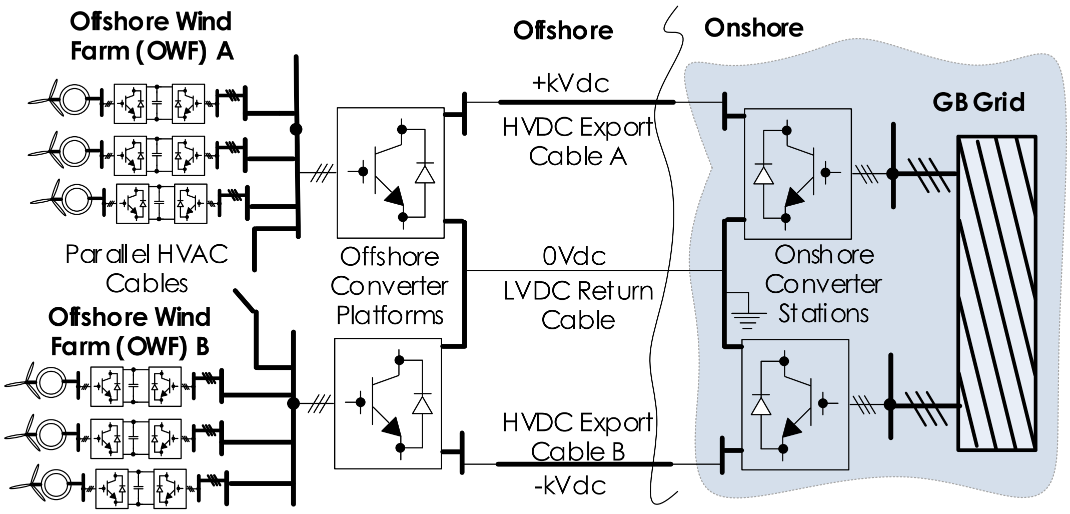


Figure 4-6 Bipole HVDC with return cable design

4.1.7. Design 6 (T6): Multi-ended High Voltage Direct Current arrangement offshore

This design illustrated in Figure 4-7 could represent integrated solutions with interconnectors or European networks. The use of offshore HVDC switching platforms to facilitate multi-terminal direct current interconnection means that this option could result in a higher cost of offshore transmission assets compared to other design options. In terms of building block suitability, this design could in principle contribute to meeting the full net zero greenhouse gas emissions ambition. To realise the full potential of this design option and to ensure security of supply, DCCBs would need to be used offshore. Whilst DCCBs are not yet operational in Europe or used offshore anywhere in the world today, work has been done to advance their readiness for use as part of possible future European grids.

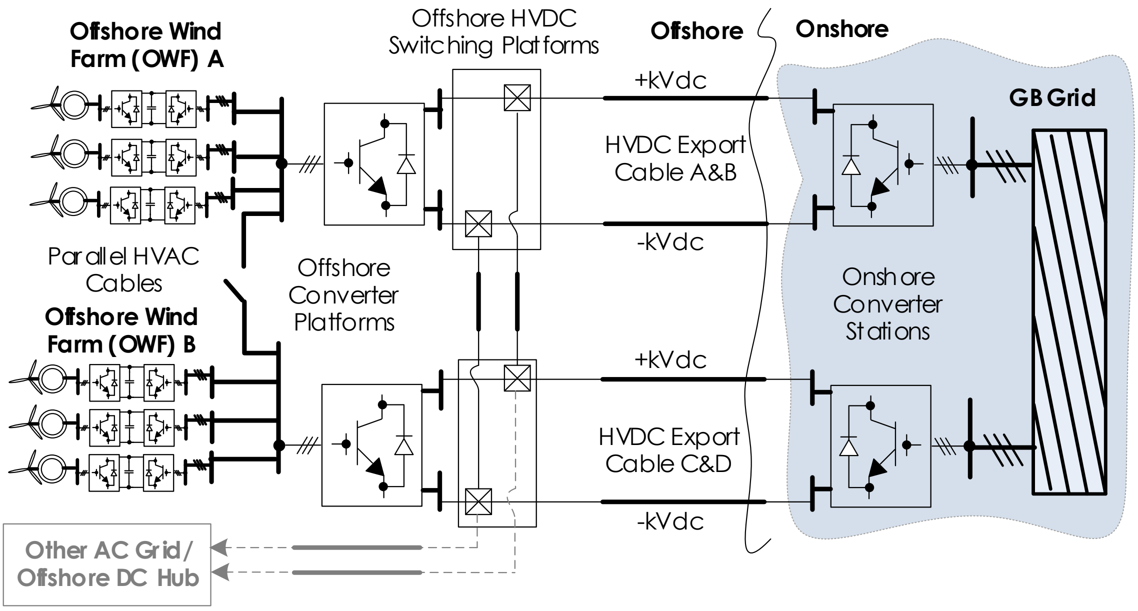


Figure 4-7 Radial multi-terminal HVDC Design

4.1.8. Design 7 (T7): 'Meshed' High Voltage Direct Current grid

This design option involves a series of offshore HVDC substations collecting the offshore power, which is connected through a meshed HVDC cable arrangement to onshore converter stations, as seen in Figure 4-8. This design of a HVDC grid would be similar in concept to an onshore integrated HVAC system but constructed offshore. In terms of building block suitability, this design could in principle contribute to meeting or exceeding the full net zero greenhouse gas emissions ambitions. This design could provide more flexibility over how power is transported to shore and would be able to limit the impact that offshore network maintenance has on individual offshore connections. The onshore and offshore HVDC switching substations would come at an additional cost compared to the other designs and design T7 would have the most complex transmission system control operation to consider and manage.

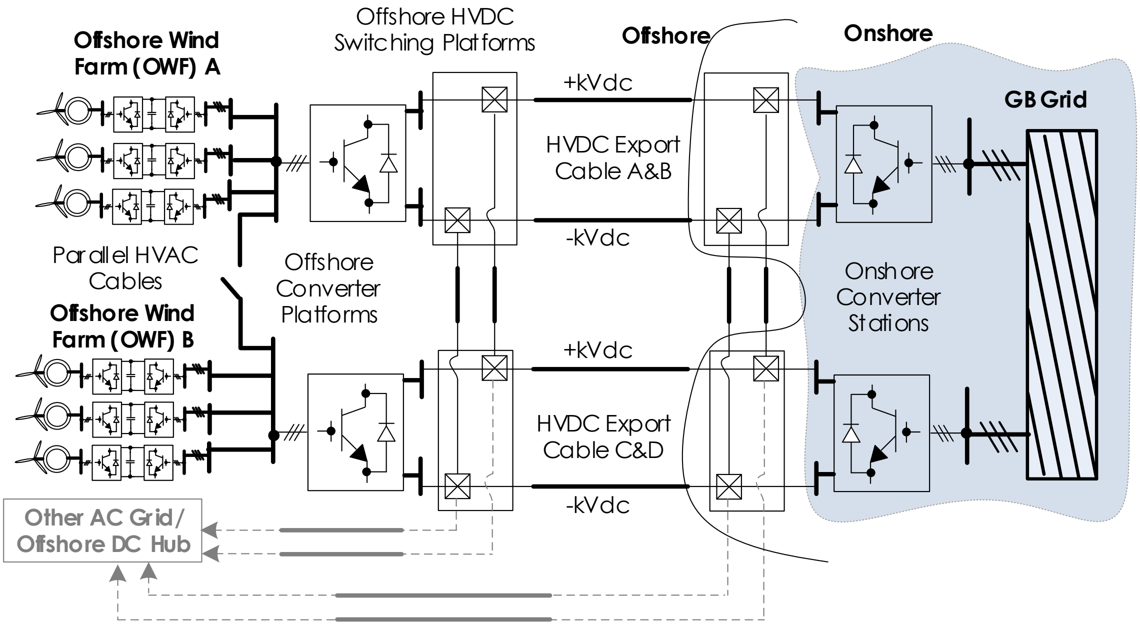


Figure 4-8 Meshed HVDC grid design

4.1.9. Overview of offshore transmission topologies

Table **4-1** is a summary of design considerations for the 8 high-level conceptual offshore network topologies identified.

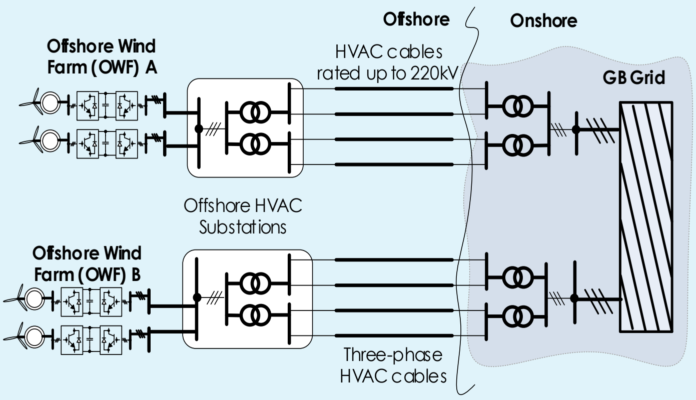
Table 4-1 Description and illustration of offshore wind farm transmission topologies

<table>
<tr><th>Topology Description</th><th>Schematic</th></tr>
<tr><td>

T1: HVAC at 50Hz: is the business as usual approach that has been used to date in GB and is well understood. Requires reactive compensation device at cable terminals and midpoint in case of transmission distances beyond 100km. Many technical considerations of increasing challenge around harmonics, control resonance states, operational configuration management, voltage regulation with scale.

</td><td>

T1: Radial HVAC at 50Hz

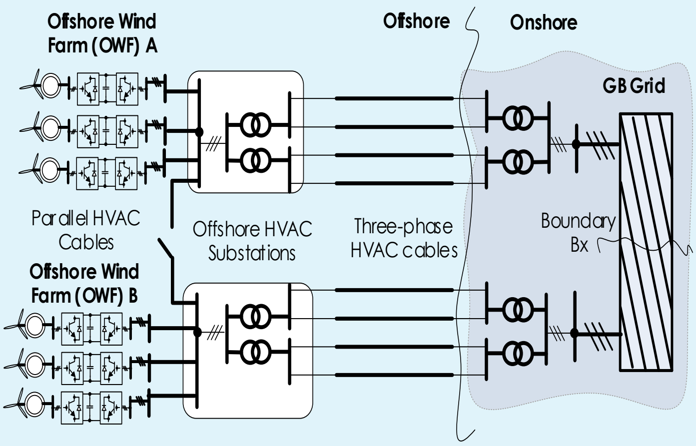


</td></tr>
<tr><td>

T1A: More Integrated HVAC at 50 Hz: Approaching capacity limits of 1.2 GW using three-phase export subsea cable circuits rated up to 220 kV and 400 MW each for viable options. Maximum distances between 100-200 km with reactive power compensation at cable ends and/or midpoint have been realised and offshore substation ratings up to 700 MW[27]. Many technical considerations of increasing challenge around harmonics, control resonance states, operational configuration management, voltage regulation with scale. Requires reactive compensation device at cable terminals and midpoint in case of transmission distances beyond 100 km. Provided sufficiently close platforms, AC platform interlinks can be realized for the supply of auxiliary power or to realize redundancy. Also, if the HVAC interlink is closed, it can facilitate options for shared use of offshore reactive compensation equipment by different projects connected via the offshore AC interlinks. No limited boundary capacity benefits to the onshore network due to limitation of AC power flow control capabilities, but can be improved by installation of additional power flow control devices.

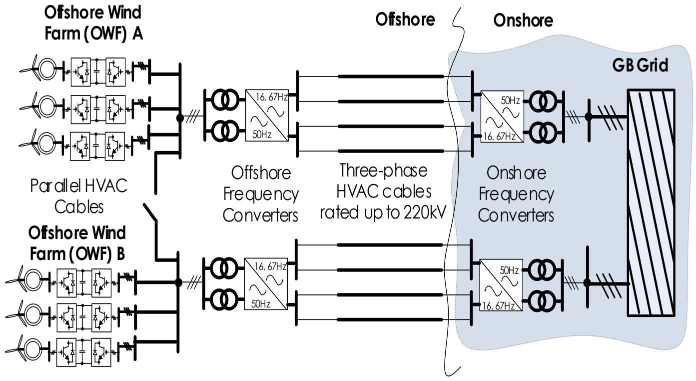
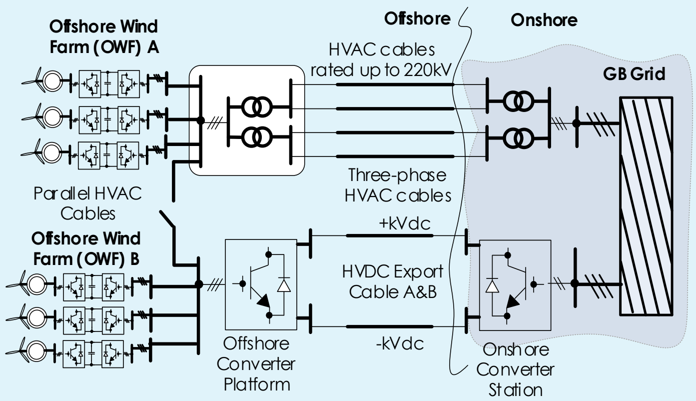
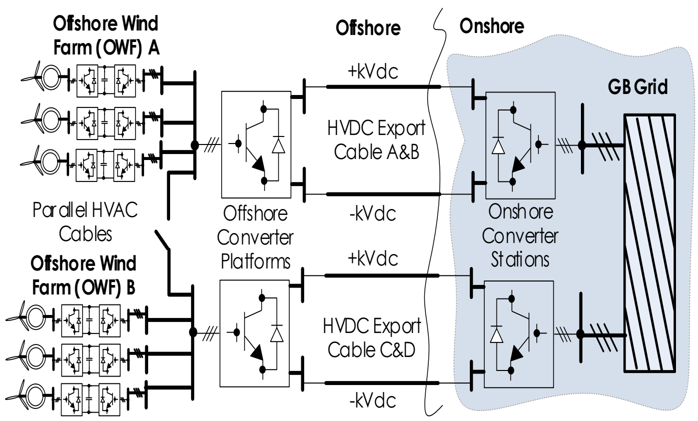
</td><td>

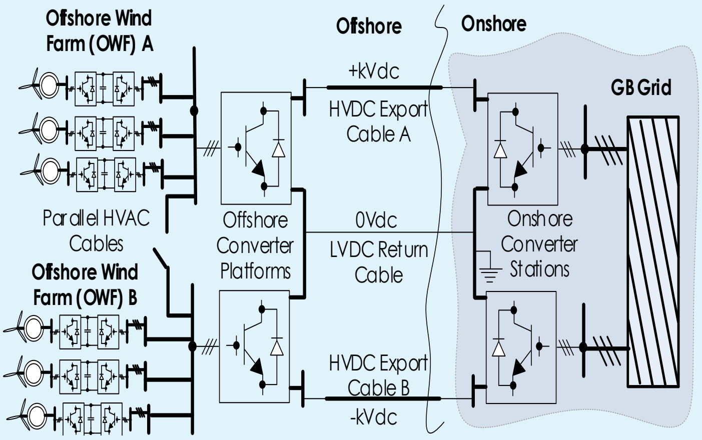
T1A: More Integrated HVAC at 50Hz

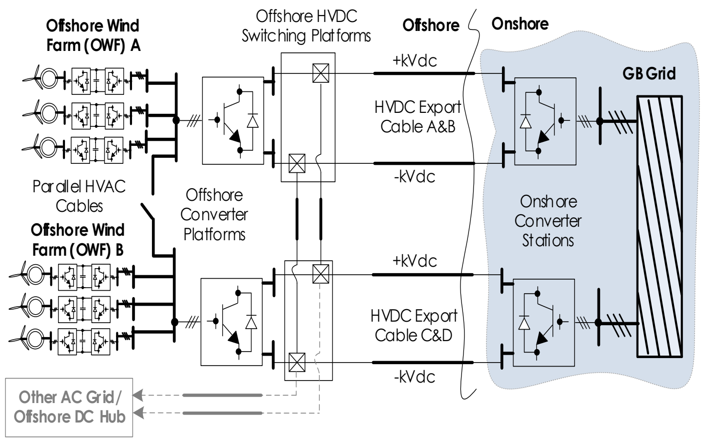


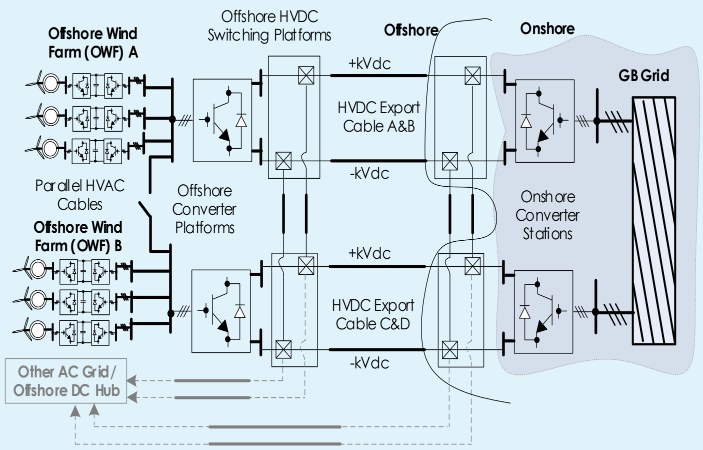
</td></tr>
</table>

[27] TenneT (2020). Energy from sea to land. https://www.tennet.eu/fileadmin/user_upload/Our_Grid/Offshore_Germany/2020_From_Sea_to_Land_Webversion.pdf

Topology Description	Schematic
T2: HVAC at lower frequency: Less harmonics, different control resonance issues around frequency transformer, similar voltage and capacity challenges as HVAC at 50Hz option. Significantly more distance possible but different limitations. Highly immature with no international precedent of scaled deployment for offshore wind farm connections and no technology pipeline for critical infrastructure. Offshore frequency converter may not be required if offshore WT generator power output is at low frequencies around 16.67 Hz. Limited boundary capacity benefits to the onshore network due to limitation of AC power flow control capabilities, but can be improved by installation of additional power flow control devices.	
T3: HVAC with parallel HVDC: Limited by HVAC transmission capacity, distance and AC interactions across control stability. HVDC has better control capabilities than HVAC, hence starts to deliver onshore boundary capacity in one direction of power flow and onshore landing flexibility via the HVDC onshore end location selection. Coordination of new build offshore generation and extensions of existing offshore wind projects possible using the parallel HVDC transmission connection. Reactive power compensation for AC cable can be provided by HVDC link. HVDC facilitates sharing of export infrastructure.	
T4. Point-point symmetrical monopole HVDC link: Limited by maximum potential loss at offshore network (currently 1.32GW capacity in SQSS), onshore landing and onshore system diversity considerations. Can offer bi-directional boundary benefits. Several converters can be connected on the AC side offshore to create offshore hubs. New grid code and process challenges around performance demonstration, compliance and operation in GB (all solve-able). International experience exists in Germany and Norway. Loss of offshore HVAC cable results in two radial HVDC links. Offshore AC interlink is limited by geographical distance offshore.	

<table>
<tr><th>Topology Description</th><th>Schematic</th></tr>
<tr><td>T5. Point-point bipole HVDC link with return cable: Minimizes cable cost, high flexibility, high availability, no existing precedent for offshore wind export, low comparative control complexity. Compatible with technology scales viable to 2030 and potential savings on offshore cable installation and offshore platform arrangements. Several converters can be connected on the AC side offshore to create offshore hubs. Opportunities limited by existing codes and standards, which can be reviewed to address maximum loss limits (currently capacity is limited to 1.8 GW infrequent loss of infeed), frameworks for incremental build, anticipatory assets and charging. Can offer bi-directional boundary benefits.</td><td>


</td></tr>
<tr><td>T6: Radial multi-terminal HVDC system: More limited flexibility and redundancy. No existing precedent for offshore wind export, higher comparative complexity. Better at interconnecting wind development zones across long geographic distances. Facilitates hybrid connection of offshore wind farms with interconnectors, offshore DC hubs or onshore HVDC bootstraps. Can be implemented using symmetrical monopole or Bipole HVDC arrangements. Offshore DC hub and protection developments required. Facilitates hybrid options with interconnectors.</td><td>


</td></tr>
<tr><td>T7. Meshed multi-terminal HVDC system: End state with high flexibility, grid equivalent redundancies possible, high comparative control, legal and regulatory complexity. May offer options for multi-transmission system operator ('TSO') integration and connection of offshore wind farms located across different countries. Can be implemented using symmetrical monopole or Bipole HVDC arrangements. Developments in offshore HVDC hubs, switchgear, protection and controls required. Facilitates hybrid options with interconnectors.</td><td>


</td></tr>
</table>

The conceptual offshore network design options in Table 4-1 provide a development stage view. Real examples for HVAC at 50 Hz do exist already in GB and other countries in Europe[28]. More integrated HVAC (T1A) options can be implemented in GB with operation of HVAC interlinks in normally closed mode and additional AC power flow control equipment can be installed at the onshore network to facilitate improved control capabilities. Low Frequency HVAC (T2) is a potential transitional option that can facilitate longer distances compared to HVAC at 50 Hz, but the technology is highly immature and there is currently no international experience of deployment at scale. Although high voltages up to 400 kV have been analysed for LFAC solutions in references [29] [30], the capacitance of the of cables will again increase at higher voltages by a factor in the order of the square of the AC voltage. Also, given that reactors are devices governed by a proportional relation with frequency, their effectiveness drops at lower frequencies and more reactors will be required at higher voltages. Whilst it is possible to up step the voltages it is not necessarily practical. Hence to ensure a robust comparison between LFAC and HVAC solutions an intermediate voltage of 220 kV is used in order to assess the potential benefits associated with the transmission distance and power ratings of the different options. Also, developments in gas insulated lines could if available extend theoretical HVAC transmission distance, subject to development of appropriate standards and demonstration across longer distances.

Examples for HVAC with parallel HVDC and HVDC radial with AC interlinks exist in Germany and will be used for projects under-construction in GB [31]. Bipole HVDC with return cable represents an option that can offer greater availability and reduced offshore cable investment compared to symmetrical monopole HVDC, while offering improved space savings on offshore platforms due to reduced DC voltage insulation and clearance requirements. Developments comprising multi-terminal offshore HVDC hubs connecting multiple platforms and different countries are in planning but do not exist yet [32][33].

The loss of the return cable conductor in T5 (“Bipole with return cable”) would turn the transmission system into a rigid bipole which would require the parallel HVAC lines between substations to be used, to equalise the loading of the two poles.

For the T5 option, It is assumed that the offshore AC interlink is normally open across all topologies. The advantage of the Point to Point Bipole HVDC metallic return topology T5 is that in case in case of a fault in a pole cable, the HVDC cable protection would block and isolate the faulted cables and the HVDC controls would maintain the power flow in the other pole cable up to a maximum 50% of the Bipole rating. Whereas in case of a fault in the metallic return the Normal Bipole mode would be transferred to rigid Bipole mode where the pole balancing control at the Bipole level would balance power in the two poles to limit the current flowing into the neutral grounding point within 1~5% of full load current as per the requirements. This transfer to rigid Bipole control would require coordination with the wind farm power to automatically balance between the two poles in the offshore AC side using the parallel / tie HVAC cable in the offshore HVAC network. Thus maintaining 100% of the power transfer capacity even during the fault on the metallic return cable. Use of the offshore AC interlink cables for power balancing may also be possible for other proposed topologies.

- HVAC at 50Hz in GB and other countries in Europe.

Developments comprising multi-terminal offshore HVDC hubs connecting multiple platforms and different countries are in planning but do not exist.

[28] TenneT (2020). Energy from sea to land. https://www.tennet.eu/fileadmin/user_upload/Our_Grid/Offshore_Germany/2020_From_Sea_to_Land_Webversion.pdf

[29] Ruddy, Jonathan, Ronan Meere, and Terence O’Donnell. "Low Frequency AC transmission for offshore wind power: A review." Renewable and Sustainable Energy Reviews 56 (2016): 75-86. https://www.sciencedirect.com/science/article/pii/S1364032115012988

[30] Xiang, X., M. M. C. Merlin, and T. C. Green. "Cost analysis and comparison of HVAC, LFAC and HVDC for offshore wind power connection." (2016): 6-6. https://spiral.imperial.ac.uk/handle/10044/1/30859

[31] TenneT (2020). Energy from sea to land. https://www.tennet.eu/fileadmin/user_upload/Our_Grid/Offshore_Germany/2020_From_Sea_to_Land_Webversion.pdf

[32] ENTSO-E (2020). Position on Offshore Development. https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/Publications/Position%20papers%20and%20reports/entso-e_pp_Offshore_Development_16p_200526.pdf

[33] TenneT and Vattenfall to study potential Dutch and UK offshore wind farm connections, 13th of June 2018, https://www.tennet.eu/news/detail/tennet-and-vattenfall-to-study-potential-dutch-and-uk-offshore-wind-farm-connections/

4.1.10. KPIs Identified

The seven different offshore topologies were assessed against the set of following set of KPIs:

- Security of supply
- Technology limitations/readiness
- Environmental impacts
- Impact on transmission system operation
- Shareability of transmission assets
- Deliverability
- Potential for future development
- Regulatory framework considerations

A more detailed summary table of these KPIs is provided in

Table 2-2 of this report.

4.1.11. Comparative Assessment of Offshore Topologies

Four key KPIs were assessed against the eight conceptual offshore network topologies which are:

- **Security of supply:** essential for network integration, an acceptable design must meet SQSS requirements and not decrease onshore system security during normal or fault conditions;
- **Technology limitations/readiness:** transmission technologies that are relevant to 2024-2050 build period, network solutions with higher power and voltage ratings can reduce the number of assets and cable circuits constructed;
- **Environmental impacts:** there are limited locations for landing and interface points with the onshore transmission system. Technologies that offer flexibility to extend offshore networks to suitable onshore connection points can reduce consent application risks, and
- **Impact on transmission system operation:** may provide benefits to other parts of the transmission system in operational timescales.

Table 4-2 is a summary of aspects of the KPI assessment performed using a RAG analysis for the eight different offshore transmission network topologies. Evaluation will be further refined across the project.

Table 4-2 Summary of KPI assessment for eight different topologies

<table>
<tr><th rowspan="2">Topology</th><th rowspan="2">Security of supply</th><th colspan="2">Technology</th><th rowspan="2">Environmental impacts</th><th rowspan="2">Impact on transmission system operation</th></tr>
<tr><th>limitations</th><th>readiness</th></tr>
<tr><td>T1. HVAC at 50Hz</td><td rowspan="2">Yes</td><td rowspan="2">About 1.2 GW, with cables each rated 400MW at 220 kV AC</td><td>9: Mature at distances up to 80km with reactive compensation at cable ends</td><td>Typically, 80-200 km. Limited to coastal landings</td><td rowspan="2">No due to limitation of AC power flow control capability, but can be improved using additional equipment</td></tr>
<tr><td>T1A. More Integrated HVAC at 50Hz</td><td></td><td></td></tr>
<tr><td>T2. HVAC at lower frequency</td><td>Frequency response capability not yet demonstrated due to low TRL</td><td>Not available at scale</td><td>2-4: requires technology development,at scale and longer distances</td><td>Up to 400 km</td><td>No due to limitation of AC power flow control capability, but can be improved with additional devices</td></tr>
<tr><td>T3. HVAC with parallel HVDC</td><td>Yes</td><td>Limited by AC link capacity.</td><td>9: Existing</td><td>Offshore distance limited by parallel AC link</td><td>Possible in one power flow direction</td></tr>
<tr><td>T4. Point-to-point Symmetrical Monopole HVDC</td><td>Yes</td><td rowspan="4">Limited by HVDC cables. Power ratings up to 4 GW and ±800 kV DC voltage available by 2030. Also, subject to existing SQSS offshore infeed limit of 1.32 GW.</td><td>9: Existing</td><td rowspan="2">Typically, up to and beyond 400km</td><td>Yes. Bi-directional flows possible.</td></tr>
<tr><td>T5. Bipole HVDC with parallel AC</td><td>Yes</td><td>7-8: Onshore project experience exists</td><td>Yes</td></tr>
<tr><td>T6. Radial multi-terminal HVDC</td><td>Yes</td><td rowspan="2">7 (T6) and 5 (T7): Control, protection and offshore HVDC switchgear development and demonstration</td><td rowspan="2">Suitable for interlinking across different offshore zones</td><td rowspan="2">No for interconnector with T-design.
Yes, for H-design with minimum of two onshore landing points.</td></tr>
<tr><td>T7. Meshed multi-terminal HVDC system</td><td>Yes</td></tr>
</table>

4.1.12. VSC-HVDC Technology Status

HVDC is the key technology relevant to future offshore transmission designs, enabling higher capacity transmission of power to the onshore transmission system via a smaller number of cables, with much longer cable distances. In contrast to LCC which have been used in several UK interconnectors, the modular multi-level voltage source converter (MMC-VSC) type, is capable of creating an offshore AC voltage with a minimum of required footprint, allowing the infrastructure to be used to pool the power of several projects offshore onto a more efficiently designed offshore platform arrangement, in comparison to cumulative HVAC developments. Table 4-3 below is a summary of the technology status for voltage source converters and HVDC submarine and land cables.

Table 4-3 Summary of VSCs and HVDC Cable Technology[34]

Technology		Maximum ratings per Converter Bipole/Cable Bipole (except stated otherwise)					
		Installed (until 2019)		Under construction (up to 2026)		Achievable (up to 2030)	
		Capacity (GW)	Voltage (kV)	Capacity (GW)	Voltage (kV)	Capacity (GW)	Voltage (kV)
VSC	With overhead lines (Asia)	3	± 500	5	± 800	7	± 1100
Extruded Cables	Cross Linked Polyethylene (‘XLPE’)	1 (Symmetrical	± 400 Monopole)	2	± 525	3	± 640
	High Performance Thermoplastic Elastomer (‘HTPE’)	Not recorded (N/A)	N/A	2	± 525	3.4	± 640
Mass Impregnated Non-Draining Cables	Paper Insulated	1	± 500	1.4	± 525	2.4	± 525
	Paper Polypropylene Laminate (‘PPL’)	2.2	± 600	N/A	N/A	4	± 800

The analysis presented in this report considers HVDC cables and converter technologies rated up to 1.3 GW per pole (2.6 GW per Bipole) at DC voltages up to ±640 kV, which are achievable by 2030 and consistent with current SQSS requirements for offshore connections.

MMC-VSC converter technology relatively easily scales to higher voltage ratings. Hence, the maximum scale of HVDC solutions to be deployed in GB will be subject to SQSS requirements, available cable capacities and offshore platform capacity. If the potential maximum loss offshore is reviewed to the same

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34 References for the table are:

- Z. Zhien (2019). The Investigation and Development of HVDC Submarine Cable http://www.jicable.org/Workshops/TGEG19/slides/session_1/1-2.pdf
- Sumitomo Electric Connects NEMO Link Cable between UK and Belgium. 18 Dec. 2018. https://global-sei.com/company/press/2018/12/prs106.html
- Sumitomo Electric Secures >€500M ‘Corridor A-Nord’”, 11th May 2020, Sumitomo Electric press release, https://global-sei.com/company/press/2020/prs043.pdf
- Amprion awards €1Bn in cable orders for A-Nord link in Germany”, 12th May 2020, Renewables Now, https://renewablesnow.com/news/amprion-awards-eur-1bn-in-cable-orders-for-a-nord-link-in-germany-698591/
- Prysmian Secures Approx. €500M SuedOstLink Cable Corridor Project in Germany”, 5th May 2020, PR Newswire, https://www.prnewswire.co.uk/news-releases/prysmian-secures-approx-eur500m-suedostlink-cable-corridor-project-in-germany-869677313.html
- Nexan successfully completed the installation of Nordlink Interconnector Cables. 21 Dec. 2018. https://www.nexans.com/newsroom/news/details/2018/12/NordLink-Nexans-has-successfully-completed-the-installation-of-four-interconnector-cables-for-2018-.html
- Prysmian secures the highest value cable project ever awarded, worth €800 million. 16 Feb. 2012. https://uk.prysmiangroup.com/uk_news003.html
- Prysmian HVDC Cables. 30 April 2020. https://www.prysmiangroup.com/en/en_hv-and-submarine_high-voltage-underground-systems_hvdc-underground_extruded-cables-hvdc-power-transmission.htm l. [Accessed on: 10 June 2020]
- NKT. 640kV extruded HVDC cable systems. https://www.nkt.com/products-solutions/high-voltage-cable-solutions/innovation/640-kv-extruded-hvdc-cable-systems

level as the onshore network (currently 1.8 GW), then HVDC cables with power ratings above 1.7 GW per cable and DC voltages rated beyond ±640 kV are achievable up to 2030 as seen in the above table.

Offshore transmission solutions with higher power ratings can reduce required total offshore cable length and reduce construction onshore which could represent options for easier build and consenting. Also, emerging technologies such as superconducting HVDC cables which offer higher capacities and occupy less space can be used to HVDC cable [35], if they become available on commercial terms and are cost competitive across the timescales under consideration. However, the maximum power capacity of any single offshore transmission circuit will depend on the SQSS requirements that can ensure onshore security of supply.

4.2. HVDC Applications in GB

The three main applications of HVDC transmission in the GB grid are: (i) Electricity Interconnections; (ii) Grid Reinforcements; and (iii) Offshore Wind Connections. A further application which is applied in Norway is supplying power from shore to offshore oil & gas infrastructure.

In contrast to LCC, VSC HVDC systems are suitable for multi-terminal extension. Multi-terminal HVDC systems can offer options for asset sharing across multiple transmission applications, hence reducing the extent of offshore cabling and onshore construction compared to radial or point-to-point HVDC solutions.

Reliable operation of shared multi-terminal HVDC solutions will depend on the load factors of the different applications, control and protection aspects and appropriate regulatory frameworks such as rules for priority access.

4.2.1. Electricity Interconnections

Electricity interconnectors use HVDC subsea cables to connect the GB grid to neighbouring countries for energy trading and balancing. Interconnectors derive their revenues from congestion revenues, which depend on the existence of price differentials between electricity markets at either ends of the interconnector. As a result, HVDC interconnectors tend to be fully loaded in either direction accordingly. European regulation governs how interconnection capacity is allocated via market auctions. Figure 4-9 shows the schematic diagram of a point-to-point HVDC interconnector, which connects two adjacent electricity grids.

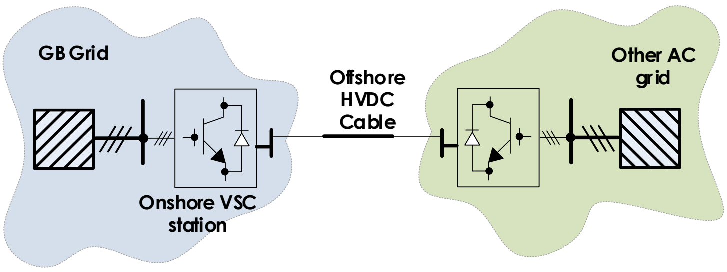

Figure 4-9 Schematic of a point-to-point HVDC Electricity Interconnector

In GB, interconnectors tend to be privately owned on a merchant basis with two types of investment arrangements either based on a regulated cap-and-floor mechanism or developers seeking exemptions from regulatory requirements and certain aspects of European legislation in order to increase safeguards for their investment.

4.2.2. Grid Reinforcements

Embedded HVDC links use two onshore converter stations remotely located from each other and connected to the same electricity grid for transmission reinforcement, boundary capability improvement and thereby facilitate integration of renewable power generation. Loading of embedded links therefore follows variable demand profiles, renewable energy generation and conventional power plant dispatch, and is not always

[35] Nexans (2019). Nexans completes successful qualification testing of 'Best Paths' superconductor cable for HVDC power links. https://www.nexans.com/newsroom/news/details/2019/06/Nexans-completes-successful-qualification-testing-of-%E2%80%98Best-Paths%E2%80%99-superconductor-cable-for-HVDC-power-links.html

fully loaded. Embedded HVDC links are implemented in parallel with existing HVAC transmission circuits. They typically tend to be owned by a single or multiple Transmission Owners as a part of their regulated asset base, depending on the network owners of the connection terminals. Figure 4-10 shows the schematic diagram of an embedded HVDC link to increase transfer capacity across the onshore Boundary Bx. A number of such developments over the timeframe of offshore development have been identified by onshore Transmission Owners in the ESOs' Network Options Assessment document as potential solutions to onshore boundary capacity limitations. Where offshore developments might otherwise contribute to that same capacity challenge, there may be benefit in a multi-terminal extension of such infrastructure to construct a third HVDC convertor terminal into which an offshore wind development may connect. The location of this third terminal could either be onshore itself, requiring associated offshore infrastructure, or the circuit landed onshore at an intermediate point on its route to connect the associated offshore wind to this circuit.

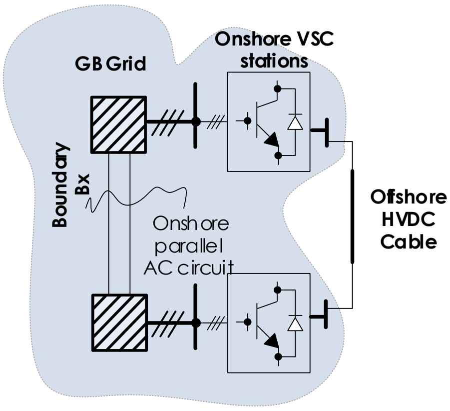

Figure 4-10 Schematic diagram of an Embedded HVDC link for Grid Reinforcement

4.2.3. Offshore Wind Connections

HVDC-connected offshore wind farms can facilitate long distance subsea power transmission connections to remote offshore wind farms. The key components are offshore platform for hosting the offshore converter station, subsea HVDC cables and onshore converter station. The loading of offshore wind HVDC connections follows the offshore wind generation and thus has a loading factor around 50%. At present HVDC-connected offshore wind farms are consented and under-construction in GB. Figure 4-11 shows the schematic diagram of a HVDC-connected offshore wind farm.

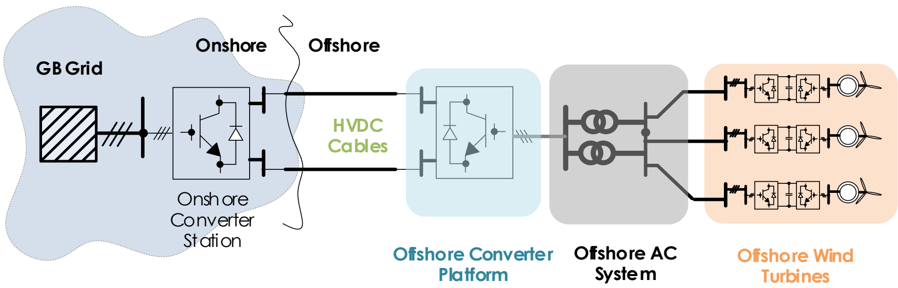

Figure 4-11 Components of HVDC-connected offshore wind farm

Electricity connections to GB offshore windfarms are typically built by developers at the same time as development of the offshore windfarm project in accordance with requirements that are set out the regulatory framework (the Grid Code). When assets are fully commissioned, they are transferred to the offshore transmission owner ('OFTO') identified through an Ofgem administered competitive tender process as part of the OFTO regime.

4.2.4. Multi-purpose HVDC Options

Multi-purpose HVDC links can be used for the implementation of electricity transmission circuits to remote island wind farms through either extension of an embedded HVDC scheme via an onshore DC hub, offshore DC hub or interconnector, thus combining different applications in one interconnected HVDC grid. These can be implemented directly using the conceptual designs presented in T6 and T7, or based on modifications to the topologies T4 and T5. Therefore, flexibility benefits associated with integrated HVDC solution's capability to assist boundary capacity management, balance the power sharing and facilitate integration with interconnectors and offshore wind farms across different regions / countries will be available to the multi-purpose HVDC options.

GB onshore transmission owners typically build transmission infrastructure linking remote islands to the mainland. Alternatives regimes such as competitively appointed transmission owner (CATO) mechanisms and other emerging regulatory models are being developed for introducing competition in the delivery of GB's onshore electricity networks.

Figure 4-12 shows the schematic diagram of an HVDC-connected AC island with an onshore DC bussing point to form a three-terminal HVDC link. This option can be built in stages with the embedded HVDC link built first, comprising two onshore converter stations and HVDC cables, followed by a final stage comprising the onshore DC hub and island converter station. An example of this arrangement is the planned multi-terminal extension of the Caithness-Moray HVDC link to Shetland Island.

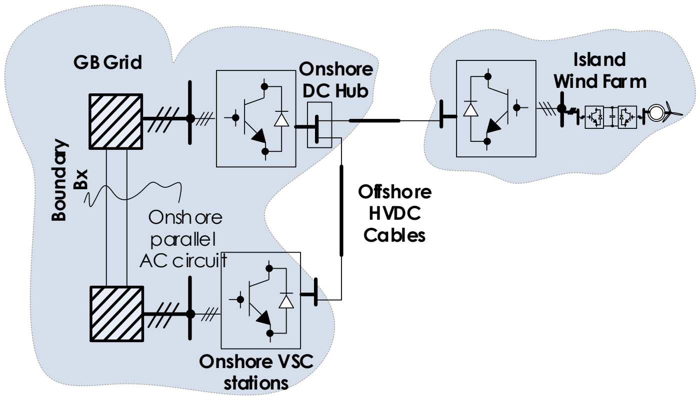

Figure 4-12 Embedded multi-terminal HVDC system with onshore DC hub

Figure 4-13 illustrates an example three-terminal HVDC system formed by an embedded HVDC link and offshore wind farm connection via an offshore HVDC hub. This option can also be built in stages. The first stage could comprise the radial HVDC link to the offshore wind farm, with anticipatory assets including the offshore DC hub and control and protection solutions for multi-terminal operation designed and tested during the first phase.

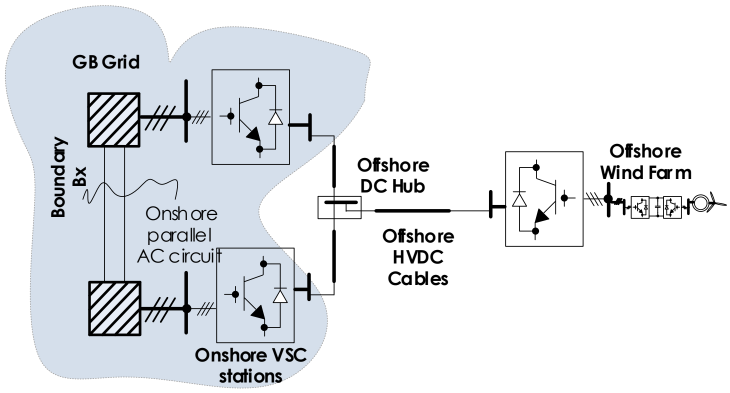

Figure 4-13 Embedded 3-Terminal System with offshore DC hub

Figure 4-14 shows an example three-terminal HVDC system formed by an interconnector and offshore wind farm connection via an offshore HVDC hub. This topology can also be implemented using a sequential build approach that considers anticipatory assets and design and testing of multi-terminal-ready control and protection schemes.

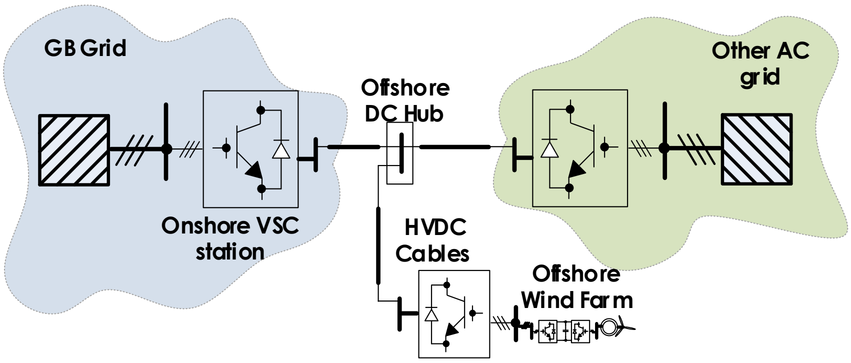

Figure 4-14 3-Terminal System comprising interconnector with offshore DC hub

The multi-terminal HVDC systems implemented to date have been centrally planned in their entirety prior to construction. This approach is unlikely to lead to cost-advantages in large-scale offshore grids as it reduces options for competitive tendering. Thus, at this stage, incremental organic growth of the offshore transmission system is expected to be the preferred grid development model. Each development step could in principle be executed by different parties, adhering to a common set of technical guidelines that guarantees compatibility and operability. These technical parameters need to be coordinated between the starting steps of the offshore grid development to ensure future expansion and interconnection is technically possible. Determining and agreeing this minimum set of technical parameters and allowing the necessary anticipatory investment for their realization is key.

4.3. GB IMPLEMENTATION OF OFFSHORE NETWORK DESIGNS

This section describes our approach to implementation of the conceptual network designs across the six regional offshore development zones in GB. Each of the possible offshore transmission network design solutions identified could contribute to meeting expected step changes to installed offshore wind capacity from 2025 onwards. Offshore wind projects that are planned for installation before 2024 have not been included within the integrated offshore transmission analysis for this assessment (refer to list of offshore wind projects in TEC register).

4.3.1. Key Elements of Developing Offshore Networks

This project focussed on using a structured approach to assess the suitability of different offshore network designs to accommodate onshore and offshore variables and facilitate delivery of the transmission connections required to meet the offshore wind targets for 2050.

Our approach considers:

- inputs that are changing regularly;
- pace of offshore wind growth for counterfactual and integrated transmission options;
- development of conceptual offshore network designs using HVAC and HVDC technologies;
- technology readiness and appropriateness for use as filters for design;
- wider benefit for onshore transmission system using detailed designs and power system analysis, and
- illustrative asset count combined with unit costs.

The key inputs to the detailed concept design process for offshore networks are:

- Installed capacity of OWF per year between 2025 and 2050: Source is FES 2020 LW scenario [36], which meets the offshore wind targets in the timeframe. The most appropriate FES scenarios would need to be nominated for future studies. Given that this project investigated only one timeframe,

[36] ESO (2020). Future Energy Scenarios. https://www.nationalgrideso.com/document/173821/download

there is an opportunity further investigate the performance of the proposed solutions across other scenarios;

- Transmission distance from offshore zones to shore: open-assess distance measurement tools provided by the Crown Estate England[37] and Marine Scotland[38] are used to calculate transmission distance from offshore development areas to onshore connection points. Whilst project location within each zone is not available, the more detail that is available the better designed the offshore network will be.
- Offshore wind load factors: the average load factor for GB offshore wind farm was used for the analysis based on data provided in FES 2020.
- Onshore Reinforcement options: The onshore network background used in this study considers projects assigned a proceed signal up to year 2029 in the ESO's NOA report[39];
- Interconnector load factors: annual load factors for interconnectors in FES 2020 is used to determine available transmission capacity for hybrid solutions comprising HVDC-connected OWFs with existing or planned HVDC interconnectors.
- Onshore Boundary Transfer Requirement: the 2020 ETYS System Requirement Form ('SRF') presents the boundary required transfers for ETYS boundaries calculated in accordance with the planning criteria defined within Chapter 4 of the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS)[40]. The analysis used in this project considers implementation of connections to the South of a constrained boundary, prior to connections to the North of the same boundary, in order to improve onshore network constraints.
- As per our KPIs, all conceptual designs taken forward for our illustrative approaches for GB are in principle deliverable. As part of that delivery, we have ensured integrated offshore network is delivered ahead of buildup of shared offshore projects to ensure capacity delivered on time. We have used the broader KPI themes in this implementation stage, balancing consideration of standardised and modular designs, and supply chain with them such that individual stages of delivery within this picture are as de-risked as they can be at this early stage.

At transmission distances beyond 200 km, only HVDC solutions were considered for both integrated and counterfactual offshore network approaches. At transmission distances below 200 km, HVAC was considered for up to 50% of the step change in OWF capacity in a given offshore area as part of integrated transmission options. In the counterfactual option, year on year growth of offshore wind capacity was assumed to have priority over distance considerations (below 200 km). For example, if OWF growth per flop zone in a given year is below 1.2 GW, integrated HVAC design was considered as the preferred option, but beyond 1.2 GW, HVDC was considered as the preferred transmission option. Individual radial connections to different offshore development zones were also required in the counterfactual for power transfer to the onshore grid.

4.3.2. North Scotland Case Study

The 2030 view for North Scotland offshore wind zone was used to assess the offshore network options in the counterfactual and integrated network design approaches to support 7 GW of installed offshore wind capacity between 2025 and 2031. Figure 4-15 illustrates offshore network design options required by 2030 to support this level of offshore wind growth in North Scotland.

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[37] ArcGIS: The Crown Estate Offshore Bidding Areas. https://www.arcgis.com/home/webmap/viewer.html?panel=gallery&suggestField=true&url=https%3A%2F%2Fservices2.arcgis.com%2FPZklK9Q45mfMFuZs%2Farcgis%2Frest%2Fservices%2FOffshoreWindLeasingRound4BiddingAreas_EnglandWalesNI_TheCrownEstate%2FFeatureServer%2F0

[38] Marine Scotland. Maps NMPI https://marinescotland.atkinsgeospatial.com/nmpi/default.aspx?availablelayers=1878

[39] ESO (2020). Network Options Assessment. https://www.nationalgrideso.com/document/162356/download

[40] ESO (2020). Electricity Ten Year Statement System Requirements Form 2020. https://www.nationalgrideso.com/document/171956/download

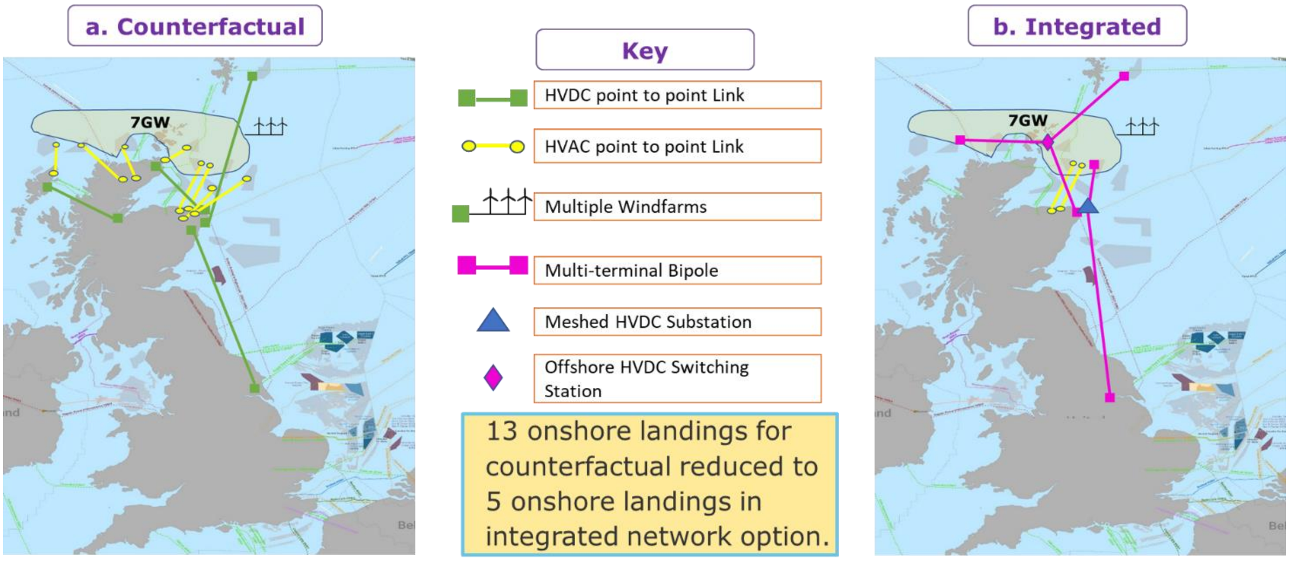

Figure 4-15 North Scotland 2030 view. (a) Counterfactual (b) Integrated

The counterfactual view (in Figure 4-15 (a)) is based on point-to-point HVAC links (yellow lines) used for individual connection of offshore wind projects to the onshore network at transmission distances below 200 km and a HVDC link (see green line) to the furthest area at transmission distances beyond 300 km. This approach would require additional reinforcements on the onshore transmission system implemented using two embedded HVDC schemes in the North of Scotland area, plus another HVDC bootstrap to transfer the offshore wind power from Scotland to load centres in England. This HVDC bootstrap would be required in addition to the planned reinforcements that were given a proceed signal in the 2020 NOA.

For the Integrated view (in Figure 4-15 (b)), a three-terminal HVDC arrangement is proposed to gather power from North Scotland offshore area to an island HVDC switching station in Orkney, which would facilitate flexible connection of multiple terminals without the use of DCCBs and ensure power transfer to an onshore converter station located in the Peterhead area. There is existing precedent of the HVDC switching station, as designed for the CMS HVDC scheme in North Scotland. An onshore meshed HVDC substation, which provide greater flexibility is used for linking offshore wind farms in the Moray Firth area into the Scottish transmission system and with load centres in England. Figure 4-16 is an illustration of a meshed onshore HVDC substation concept comprising four DCCBs and multiple DC selector switches to facilitate flexible connection of four HVDC converter terminals. DCCBs have been deployed at industrial scale in Asia on HVDC projects involving European manufacturers [41].

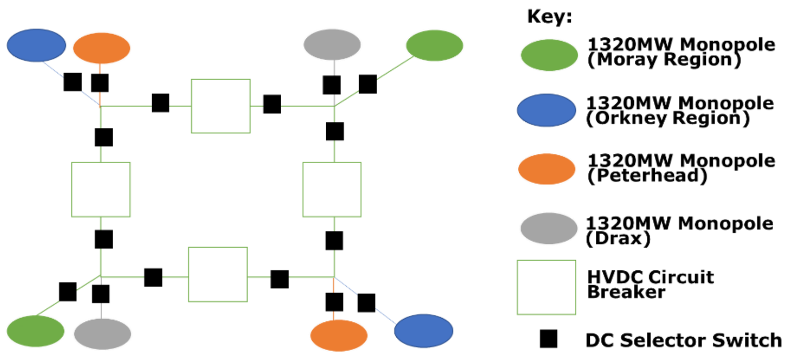

Figure 4-16 Meshed Onshore HVDC Substation Concept

[41] HitachiABB (2019). Zhangbei: The world's first DC-grid with HVDC Light technology. https://www.hitachiabb-powergrids.com/references/hvdc/zhangbei

Also, integrated HVAC options are proposed as part of this design option for connection of near-shore sites in the Moray Firth to the onshore grid.

The integrated offshore network design approach offers significant (up to 60%) reduction in the number of onshore substation and cable landings required compared to the counterfactual approach (seen in Figure 4-16). An offshore network design that ensures reduction in asset count could result in easier construction, reduce consenting risks, offer amenity benefits and has the potential to achieve lower costs (subject to detailed CBA), compared to a solution with higher asset count. An illustrative asset count was performed to compare the counterfactual and integrated offshore network designs. The wind turbine to collector hub infrastructure are considered to be the same for both integrated and counterfactual options. Figure 4-17 shows the asset count for the North Scotland 2030 view of offshore network designs.

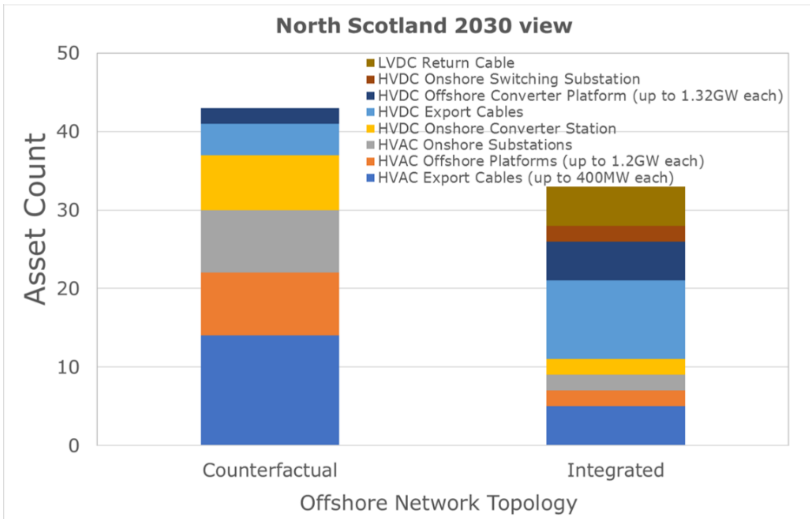

Figure 4-17 Illustrative Asset Count for North Scotland Case Study

Asset shown in Figure 4-17 for illustration and a full scale of asset requirements was provided for CBA assessment. Also, details of offshore network design considerations for the 2050 view of North Scotland informed the power system analysis work.

4.3.3. North Wales and Irish Sea Case Study

The 2030 view for North Wales and Irish Sea offshore wind zone was used to assess the offshore network options in the counterfactual and integrated network design approaches to support 2.58GW of installed offshore wind capacity between 2025 and 2032. Figure 4-18 illustrates offshore network design options required by 2030 to support this level of offshore wind growth in this area.

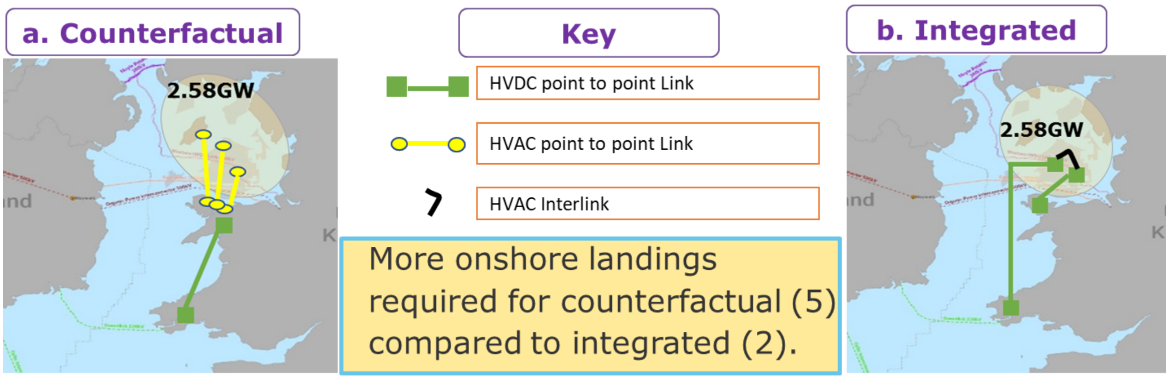

Figure 4-18 North Wales and Irish Sea 2030 view. (a) Counterfactual. (b) Integrated.

The counterfactual approach in Figure 4-18 (a) considers individual HVAC links (see yellow lines) connecting different offshore wind projects to the onshore network in the North Wales region, with an additional HVDC link (see green line) into the South Wales region in order to reduce onshore network constraints.

The integrated design (in Figure 4-18 (b)) was based on two HVDC links each connecting the offshore wind zone into both North Wales and South Wales. The offshore converter platforms were connected using HVAC interlinks, which facilitate provision of boundary capacity service for reducing onshore network constraints.

The integrated option would require less onshore landings for substation and export cables than the counterfactual design. Figure 4-19 shows the illustrative asset count for the 2030 view of offshore network designs for the North Wales and Irish Sea region.

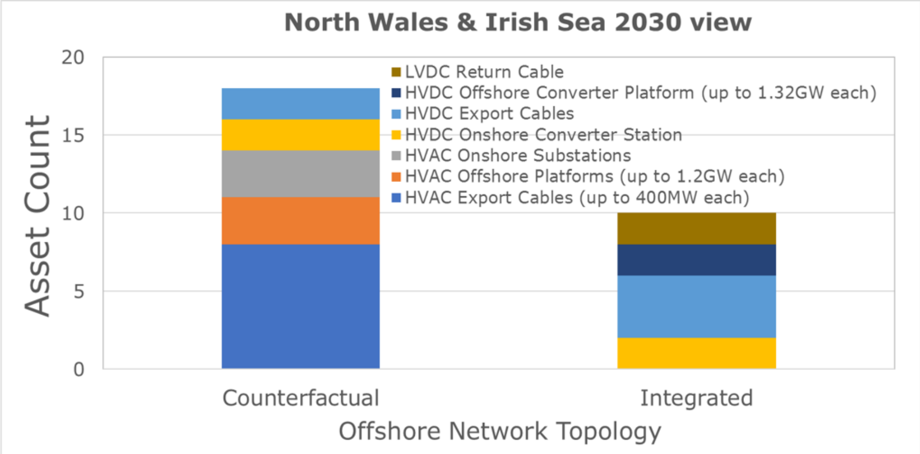

Figure 4-19 Illustrative Asset Count for North Wales and Irish Sea Case Study

The integrated design option could offer up to 40% savings on the total number of assets required to connect the offshore wind zones to the onshore network.

4.3.4. GB Implementation of Integrated Designs by 2030 and 2050

Integrated offshore network designs have potential to utilise existing onshore convertor stations for hybrid integration of offshore wind farms with existing interconnectors, establish new offshore multi-terminal arrangements, avoid excessive onshore reinforcements and reduce onshore landings. They can use HVAC offshore interlinks or HVDC hubs to facilitate alternate power flow options for the transmission system. The hybrid interconnector schemes could be implemented across offshore wind farm zones in the North Sea region. Figure 4-20 provides an illustration of an integrated offshore network design option implemented across GB by 2030 and 2050.

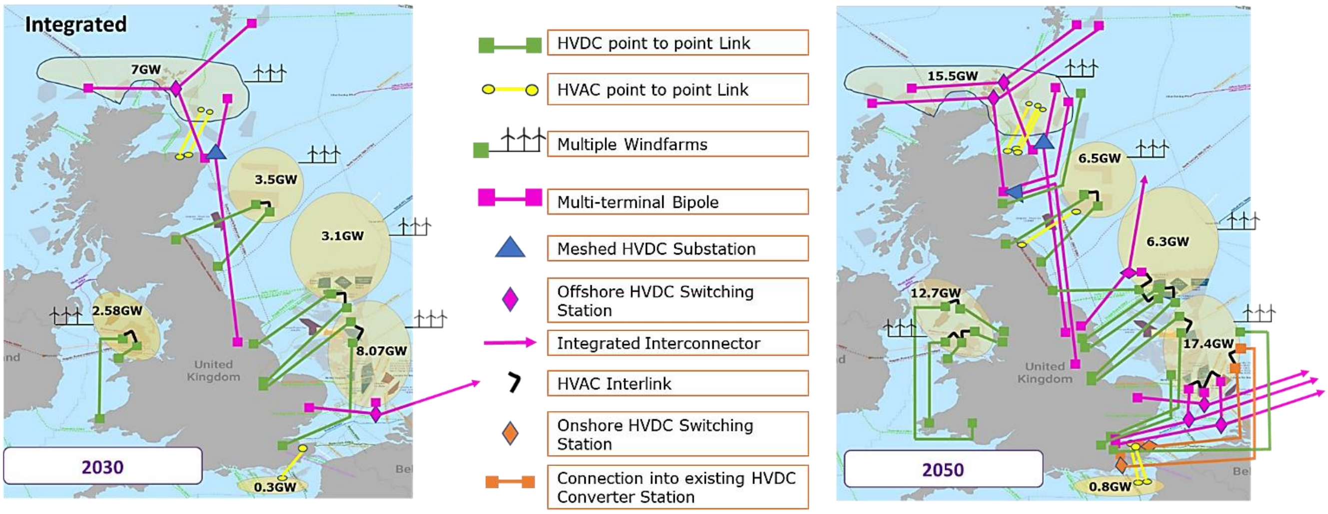

Figure 4-20 GB Implementation of Integrated Design. (a) 2030. (b) 2050

Note that in the above figure 35% extra transmission capacity in 2030 supports installed OWF capacity up to 2032.

Figure 4-21 shows the asset count for onshore cable corridors and onshore substations for both counterfactual and integrated offshore transmission designs in the GB 2030 view. The integrated transmission design option has potential to offer up to 55% reduction in the number on onshore cable corridors and up to 68% reduction in the number of onshore substations compared to the counterfactual design.

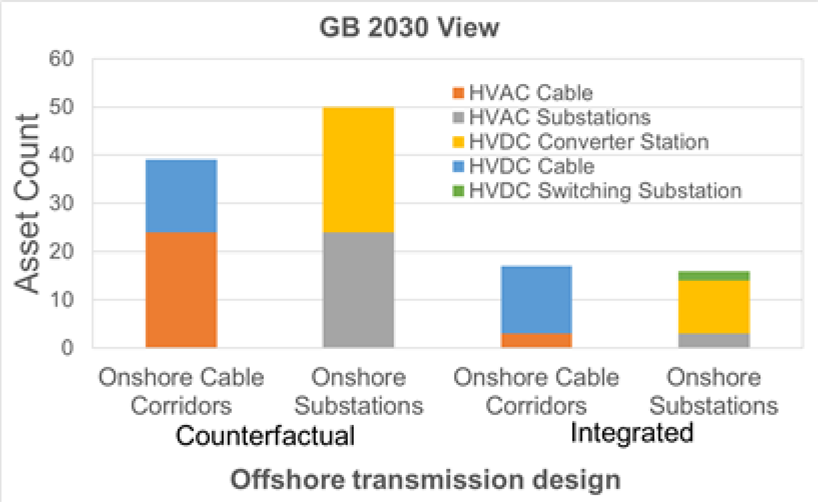

Figure 4-21 GB 2030 view of onshore cable corridors and onshore substations

Figure 4-22 shows the asset count for onshore cable corridors and onshore substations for both counterfactual and integrated offshore transmission designs in the GB 2050 view. The integrated transmission design option could offer up to 58% reduction in the number on onshore cable corridors and up to 65% reduction in the number of onshore substations compared to the counterfactual design.

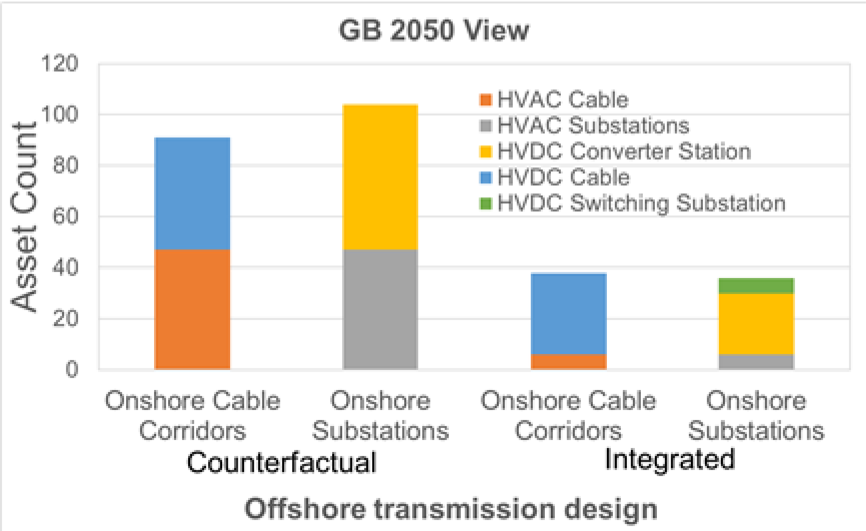

Figure 4-22 GB 2050 view of onshore cable corridors and onshore substations

In summary, key aspects for the 2030 and 2050 integrated designs are:

- Both HVAC and HVDC solutions are represented, as are integrated interconnector solutions which are mainly based on a common HVDC busbar (located onshore or offshore) for connecting interconnectors and offshore wind farms into an existing or planned onshore convertor station.
- Conceptual designs T1, T1A, T4, T5, T6, T7 are represented. The 2050 view may require concentrations of HVDC at developed industrial locations which would be expected to require careful management. The locations shown are not deliberate but were informed by transmission system boundary requirement considerations.

- Integration within and also across offshore development zones was considered, including possible integration between Dogger Bank, Eastern regions and South East included.
- None of the options gets as far an offshore HVDC mesh. However, North of Scotland approaches include the option of an onshore HVDC mesh substation (in the future) to maximise availability and onshore network security that comes from the design. The CBA assessment will inform on how this option may be supported.
- All of the options take into account and seek to mitigate boundary transfer challenges otherwise arising and select onshore connection points which are suitable for avoiding consequential boundary investment. As such these have the potential to avoid/delay onshore transmission investments, although this will likely only impact planned investments beyond 2030.
- Bipole-based HVDC solutions with HVAC interconnection appear to be the key building blocks that offer greatest flexibility in terms of reduction in asset count. These options could be implemented as separate symmetrical monopoles connecting across key boundaries, if required.
- By 2040 in a limited number of cases cable capacities of 3.6GW would be needed to support Scottish offshore zones. If market has not evolved beyond one current provider and limited experience of installation, lower capacity cables in parallel would be required.

These design solution options were used as inputs for both the power system analysis and also for the CBA work.

5. OVERCOMING BARRIERS

Potential barriers to the delivery of offshore network infrastructure that facilitates 2030 and 2050 targets being achieved, have been identified as part of our assessment. This section provides a summary of options and potential pathways for overcoming the barriers identified and discusses wider considerations of:

- integrated offshore transmission network challenges and other (in addition to offshore wind connections) potential use that could be made of offshore transmission networks;
- technology maturity and pipeline including areas of technology developments expected over the next 30 years;
- HVAC technology specific technology (HVAC cables) and system integration (harmonics, stability and power flow regulation) barriers;
- HVDC technology specific technology (interoperability, standardisation and supplier availability) and system integration (different HVDC voltages, mixed converter technology and HVDC grid protection) barriers;
- power flow regulation and other technology neutral barriers identified;
- regulatory framework rules that may constrain future offshore transmission development options;
- risks to achieving more coordinated offshore transmission network development, and
- possible route map options for overcoming identified barriers.

5.1. Integrated Offshore Transmission Network Challenges

Section 3 provides an overview of "real world" consideration of the maturity and pipeline availability of those technologies which may be applied to integrated offshore technologies of incremental scale and complexity and the barriers and opportunities. These are complemented by other challenges surrounding:

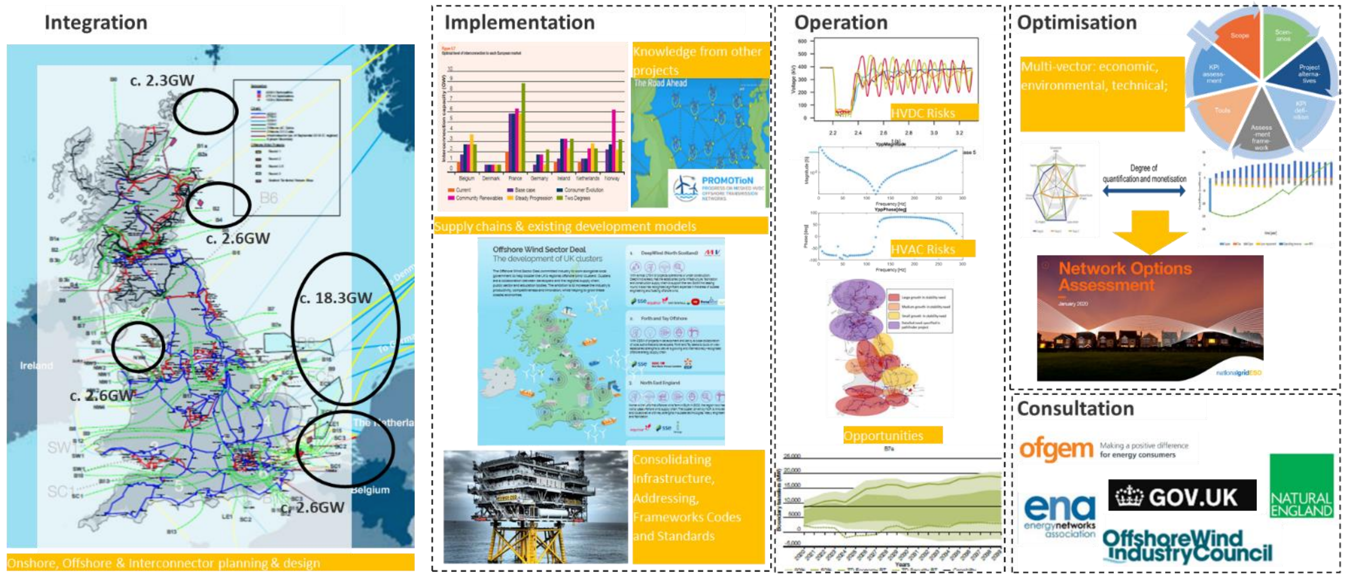

Figure 5-1 Overview of integrated offshore challenges

Integration – integrated offshore transmission networks are by no means the only aspect of offshore development. The full context of this informs the deployment of conceptual designs, their costs, their operational concepts and code and framework impacts.

- A growth of some 30 GW of interconnector capacity is anticipated over the same time period (up to 2050) of which some 75 GW is proximate to offshore wind development zones ('WDZ') considered as part of this assessment. Both new and retrofitted inclusion of offshore wind connections where practicable, were considered in order to where appropriate seek to consolidate overall development footprints arising from offshore growth.
- The future decarbonisation picture includes a total of some 23.8 GW of hydrogen production facilities (that are not connected to the transmission system), supporting an evolving future net-zero economy. Whilst, from the data provided under the 2020 FES process this is not anticipated to be a factor in the initial meeting of 2030 targets, in approaching 2050 targets this demand presents both a consideration in the design of the offshore transmission networks themselves and in the capacity the onshore network could be required to accommodate.

- Across the transition to net-zero carbon solutions, as discussed within the FES, other complementary developments of new nuclear build, new onshore wind, solar, combined heat powerplant (CHP), biomass and other technologies are being introduced to a changed extent within the energy mix influencing onshore network development requirements.
- Many of these influences are also shared across the coastal locations subject to onshore transmission network interfacing consideration. A lack of appropriate consolidation of offshore infrastructure, where it is technically possible to do so, may drive constrains on the volumes and locations of offshore developments required in future years. Ensuring an overall optimal programme of development which sensibly minimises amenity impact and overall cost whilst maintaining overall GB transmission system integrity was a key consideration as part of this assessment.

Implementation across the range of activities, currently each activity is subject to individual considerations of framework, timing and project delivery - no attempt to share requirements across projects is envisaged and evolves by exception as a result. Sequencing of future offshore developments to provide clear "forward guidance" across the range of activities that may be beneficial to provide clarity to projects and their vendors over how to interface one another, how to stage construction and what to construct. Such clarity is critical to avoid unnecessary delay or project risk limiting the ambition of achieving net zero targets. Key related factors are:

- Interconnector and other European activities in the offshore space: within and beyond UK territorial waters, other European entities may also be taking forward offshore developments – the opportunities and risks associated with consolidation must be considered from both a legal and regulatory standpoint (e.g. on what basis, under what jurisdiction and frameworks; including access and remuneration), together with the technical standpoint (e.g. differing security of supply requirements and considerations, different technical codes and associated performance requirements and capacity expectations in each TSO area, differing approaches to operation and control, more complex and dynamic power flows requiring support within an increasingly more flexible and higher capacity integrated offshore design), to ensure the appropriate balanced position on implementing integration of these parallel routes with the onshore HVAC transmission system.
- The scale of meeting a capacity of at least 40 GW of offshore wind by 2030 whilst achievable represents an unprecedented challenge of construction and deployment at a pace supporting its delivery. Considerations of supply chain delivery, standardised and modularised approaches which maximise the potential for consistent and scaled implementation must also be considered against the broader horizons of offshore development. This would ensure that the appropriate delivery approaches to meet 2030 do not unduly fetter an optimised subsequent transition towards offshore wind delivery scales of 75 GW or greater by 2050 potentially as combined with demand associated with hydrogen production facilities over the intervening period. To deliver this, different arrangements above and beyond the sector deal may need to be considered which provide clarity over an extended period to the manufacturer base to order and deliver at volume. Such an approach if combined with incentives to trial and develop supporting technology that allows modular delivery more efficiently will provide an opportunity that substitutional technology innovation is actively promoted and delivered in a timely manner.
- Control system innovation is an unavoidable and often positive component to the development of HVDC technology- however the fundamental controls themselves are often opaque in nature to the planning engineers integrating them. As illustrated within the testing and development of the Johann Sverdrup project, it is only possible to deliver co-ordinated controls if there is co-ordination of the vendors involved- specifically to make available to each other and the project more generally the high-level principles upon which these control systems are based. On that basis it is possible within a common simulation environment whilst respecting Intellectual Property ('IP') to engineer overarching control approaches which respect the innovation and IP of an individual manufacturer.

Operation of both HVDC and HVAC solutions needs to reference existing onshore system performance and trends in order to perform adequately. Key areas of consideration are:

- **Fault ride through performance:** Not merely to withstand but also to actively support the network with well tracked injection of reactive and/or active currents in the appropriate phase. Both the HVAC and HVDC devices have control schemes based on measurements - which need to perform adequately across the range of jumps in measured information and scale of voltage and frequency disturbance that can occur for onshore and offshore faults. This includes the effect of these disturbances on a weaker onshore system across which the effect of a voltage disturbance becomes more significant across a wider area of the network than before, which may include impacting at the same time more than one onshore end of the integrated offshore system being connected. For such events the frequency of the network as illustrated in the Enhanced Frequency Control Capability (EFCC) Project[42] and Investigation & Modelling of Fast Frequency Phenomena ("F2P")[43] project will not be the same across the network instantaneously and this in turn means multiple onshore ends of an integrated network may need to respond to different frequency measurements of that onshore system.

- **Large signal (fault & step change) stability:** – an ability not merely to ride through a fault but respond to the consequence of its clearance deploying adequate proportions of active and reactive power in a stable damped manner to support recovery of the offshore connection and the wider system to which it is connected.
- **Small signal stability:** HVAC solutions in particular will be subject to inherent resonance in their AC network design that will give rise to particular states of vulnerability to small step changes in voltage or angle in the steady state, or as a result of a fault. Within a HVDC connection a current loop within the control of the project can give rise to similar vulnerabilities.
- **Subsynchronous interaction:** Whether mechanical or control system in nature, a range of sub 50Hz frequencies of interaction with other devices may arise between offshore networks whether HVAC or HVDC in nature when in close proximity to series compensation and/or synchronous generation.
- **Harmonic interaction and withstand:** In addition to thermal considerations of harmonics, which are well documented, as short circuit level declines both HVAC and HVDC power electronic components need to be both rated for and capable of withstanding short bursts of harmonics, which become greater in magnitude and closer to 50Hz as the network becomes weaker.
- **Negative phase sequence resilience and withstand:** conventional converter controls seek to measure effective balanced network voltages and respond with balanced current injections. This approach is attractive in avoiding voltage control and rating challenges within the HVDC converter itself but can challenge responses to unbalanced currents driving over-voltages in response to high unbalance which in turn can challenge resilience to network negative phase sequence (NPS) considerations which are currently quantified on a thermal basis only. As the availability of conventional generation declines, their damper windings which function as a source of reducing Negative Phase Sequence (NPS) current, are reduced, and as short circuit levels fall the levels of NPS potentially increase for high transfer or unplanned transfers within the onshore system. This can lead in turn to impacting HVDC and other power electronics such as wind turbines and SVCs and STATCOM devices leading to restricted power transfer or protective tripping.
- **Control interaction:** control interactions may relate to interactions with other Flexible AC Transmission System ('FACTS') devices with similar control functionality and complementary tuning of gain or response criteria or speed, or in the indirect tracking of the effect of those devices via the network disturbance such that a power system oscillation is supported (e.g. inter area frequency oscillation or control system tracking of more localised voltage oscillation). This oscillation can build and lead to protective action or otherwise persist in an inadequately damped manner degrading stability margins to further disturbance.

Across the above areas, adequate visibility of the overall control philosophy of the connection and the devices related to that control such that these considerations may be properly modelled enables appropriate damping controls and specification to be realised. Further discussion and quantification of the trends in these operability areas can be found within the ESO's System Operability Framework document.

Optimisation: Offshore transmission networks are currently subject to optimisation across the ESO's Connection Infrastructure Options Note ('CION') and the NOA optimisation of consequent onshore reinforcement. The process at present however does not easily lend itself to a holistic optimisation of both the connection *and* the onshore wide consequence of it and the opportunities that integration with other connection activity offshore presents. This is potentially resolved by integrating into business-as-usual the process by which the conceptual designs identified as part of this project can be applied to the transmission system. This points towards a process which periodically:

- Reviews available technology and associated conceptual designs and updates where new options in either are available.
- Applies these conceptual designs to an agreed long-term plan of anticipated project developments:
    - Conceptual designs forming "building blocks" to achieve modular build up in capacity; and

[42] https://www.nationalgrideso.com/future-energy/innovation/projects/enhanced-frequency-control-capability-efcc

[43] https://www.smarternetworks.org/project/NIA_NGSO0007

  - Review of system boundary flow establishing key cross boundary capacity opportunities from integrated offshore network design, and preferred connection locations which limit onshore consequence from connections.
- Review of opportunities for integration via hybrid arrangements with interconnectors and/or European grids and adapting proposals accordingly.
- Define control principles of integrated designs and validate performance in power system analysis.

Stakeholders (impacted by the above activity): not only is management of stakeholder interests key, but also obtaining inputs from stakeholders to inform the work. Additional areas of data that would better support such optimisation would include:

- Status reporting of offshore project activity and commitments similar to that provided by Transmission Owners within the NOA to inform and limit periodic optimisation to areas of benefit and to avoid disruption.
- Project capacity build up across the period of analysis including the locations offshore and prospective scales of projects not yet subject to crown estates leasing that inform the offshore collector hub locations of these integrated designs and their sequential build up in greater detail.
- Standardised technical data exchange across development stages which enables co-ordination across offshore projects as they develop and build upon each other.

5.2. Technology Maturity and Pipeline

Technology developments are expected between 2020 and 2050 but it can be difficult to predict which options that are visible on the "development horizon" will be progressed within timescales needed for the connection of new offshore wind farms. The “development horizon problem” relates to the timeframes across which new technologies are identified in vendor development for potential deployment (normally no longer than 7 years into the future) and defines the range of technologies whose maturity, capability and fitness for a given application may be assessed. There is a “first adopter” problem, as technologies on this horizon need to see sufficient adoption to drive supplier capability and demonstrate reliability. Yet adoption in volume is similarly dependent on such capability and reliability demonstration. These two challenges may be simultaneously addressed by a strategic approach to technology delivery which comprises:

- Common equipment standards which are functionally clear but supplier agnostic.
- Clear testing requirements which are specific, repeatable, and clearly verifiable.
- Data exchange of models which are fit for purpose, verified against tests and maintained across the project lifecycle, and as such may be used to verify control and integration proposals.
- Common standards for in-service performance data collection and event review which progressively inform deployment.
- Full-scale demonstration of key technologies to give confidence in their maturity and reliability.
- Modular approaches which allow interfaces between stages of development to be clearly defined and support co-ordination and flexibility in the incremental construction of the integrated offshore environment.

Availability, capability and performance of “beyond development horizon” technology in is by its very nature yet to be defined. As such, speculative consideration of innovative opportunities across the wide array of research and theoretical solutions and a range of academic and industry literature is limited in informing practical solutions at this time. Such innovations may be realised in future years, but cannot at this stage be integrated into an implementation strategy. The effect of such innovations will be either:

- “Substitution” technologies which allow existing conceptual designs to be delivered using potentially more efficient components (e.g. super-conducting cables). This includes evolutionary innovation such as increased HVDC cable capability in voltage, temperature and cross section driving, with other developments higher ratings or more efficient solutions, evolving materials and developing new manufacturing facilities, or
- “Revolution” technologies which enable new approaches to design, and/or greater or more flexible connection of offshore capacity (e.g. specific types of grid-forming control philosophies across HVDC and wind farm designs).

The challenge in these areas of innovation is to remain open to future efficiencies (noting that these may come in a variety of forms (for example cost, manufacture time/volume, loses, integration) whilst avoiding pre-empting a dependence on as-yet unrealised approaches which would then risk deliverability. This is addressed by:

- Defining approaches mindful of existing technology capabilities that set a viable offshore solution. Within that solution identifying the opportunities for increased efficiency that may be realised by innovation.
- A clear innovation strategy for relevant integrated offshore strategy setting the key priorities for innovation that deliver those more efficient solutions, focussing on our key areas of KPI for conceptual designs.
- Standards for equipment which are flexible to interfacing with substitute technologies as they are realised.
- An innovation "pipeline" such that revolutionary technologies may be simulated, tested and trialled in a clear structured manner that allows the de-risking of their development, and clarity over the timeframes for deployment and benefits provided by their development at each stage. For example, there have been a number of existing project examples where trial of innovation was financed ahead of large-scale deployment on those projects and via an innovation strategy should seek to structure prioritised support of such opportunities over a longer lead period.

Other technologies outside of but relevant to the purpose of offshore transmission are also set to emerge over the next 30 years. There is yet undefined potential for hybridisation of offshore areas for the extraction of for example tidal generation resource, or indeed further exploitation of offshore infrastructure via floating solar arrays as have been deployed within the GB system in lakes and reservoir environments and/or implementation on the offshore platforms. Another expected offshore activity may relate to the hydrogen production industries that may yet emerge and are contemplated within FES scenarios. These industries, where supported offshore, would be expected in the first instance to remain "off-grid", however should the appropriate opportunity emerge could be included within a larger offshore grid. The flexibility to do this should be included within future offshore network designs however the specific nature of these connections is impossible to quantify at this point. Given that these demands are inherently intermittent in nature, the surplus net power from these production facilities that might arise would influence overall capacity levels serviced by these networks. As such their economic benefits of integrations would be dependent on the extent to which associated levels of generation supporting the hydrogen production could be reduced by those connections. Offshore oil and gas platforms repurposed under end of life considerations may influence opportunities in these areas.

5.3. HVAC Specific Considerations

5.3.1. Technology Barriers

5.3.1.1. HVAC Cables

The interaction of the HVAC cable with the other system(s) is the main barrier for HVAC solutions. Cables act like long co-axial capacitors, and since capacitance increases with cable length; long cables have a high capacitance. This capacitance requires current to 'charge' the cable. For HVAC cables charging is needed every cycle, and this extra current causes additional losses and uses-up current carrying capacity. For long HVAC cables, the entire current capacity of the cable may be needed just to charge the cable (approximately 50 km at 400 kV and 80 km at 220 kV).

Capacitance also has the effect on the system of increasing voltage, therefore there is a limit to the length of cable that can be used before compensation needs to be introduced to offset that voltage increase to keep the voltage across the length of the cable within allowed ranges. For offshore applications this would require a platform to house the reactor(s). The further from shore the more reactors would be required along the cable's length. The voltage profile along a cable also depends upon the loading therefore will change depending on the wind farm output, since this changes dynamically it means that dynamic voltage support may be required. The more flexible the voltage support the more complex, costly and/or large it would be.

Traditionally, to transport more power and/or for a greater transmission distance a higher voltage is used as it means more power for the same current (i.e. conductor diameter) and has lower losses. For long offshore cables this is an issue as both increased length and higher operating voltages would mean such a cable would generate more reactive power and therefore any associated issues would be exacerbated. This is part of the reason that long subsea cables that have been used for projects at up to around 220 km operating up to 220 kV include intermediate reactive power equipment platforms in their design. This is echoed in OFTO feasibility work in these areas for example that of Econnect[44]. Further options discussed

[44] https://www.windpowermonthly.com/article/1021181/build-offshore-grid

in our technology report include low frequency transmission solutions. Use of LFAC for transmission has the following challenges:

- Low technical maturity- significant R&D effort and expenditure to develop at scale required.
- New type registration and testing requirements.
- Challenges across frequency regulation and response and fault ride through to be addressed in meeting Grid Code.
- Defers compensation and resonance challenges of HVAC to longer >400 km distances, but these challenges when re-established are harder to mitigate given the peculiarities to the LFAC approach which incur greater cost and infrastructure than the HVAC approach[45].

Alternative cable technologies have been proposed that could enable higher power transmission ratings per single line using HVAC. Notably, the high temperature superconductor ('HTS') lines and the gas-insulated lines ('GIL') have received some attention over the past 30 years. The benefit of HTS is that the resistance of the conductor is close to zero and it is possible to transmit higher power at lower voltage using current in the range of tens of kilovolts. As of today, HTS materials are expensive and scarce, which makes it very costly to build a transmission system of hundreds or even tens of kilometres, so it is unlikely to be a viable option in the near or even medium term. On the other hand, GIL use conductors in pipelines with pressurised dielectric gases. GILs have very low stray capacitance, which enables them to use high voltages with little stray currents. GIL is a fairly mature technology with transmission distances up to 12 km as of 2020. These are said to require little maintenance with high reliability. It is estimated that they can achieve about 70 km transmission distance at 400 kV without compensation. The current rating of a single line can be of up to 5 kA. Most existing GIL systems in operation cover short transmission distances (~1 km) and none are subsea. Previous analysis concluded that as it requires to be installed in pipelines it would be an uneconomical option at this time. The problem with these technologies is they do not work well at the bottom of the sea where pressures are higher and temperatures are lower. Gas management and temperature management are practical problems that unhinge these solutions. Potentially larger cross-sections of conductor providing additional thermal inertia and better insulating technologies could advance these option- this requires innovation- nanomaterials such as graphene may emerge to resolve mechanical limitations to this approach but at present have a limited and high cost supply base.

5.3.2. System Integration Barriers

5.3.2.1. Harmonics

Harmonics exist on all AC systems. They are an issue when the level of the harmonics distorts the fundamental signal beyond what is acceptable to the connected equipment. They are a function of harmonic-producing equipment outputs and the impedance of the system. The capacitance introduced by long HVAC cables has the effect of changing the system impedance such that it exacerbates the distortion caused by harmonic producing equipment; it lowers the system resonant frequency towards the frequencies of harmonics generally present on the system. Given that the wind turbines used in the offshore wind farms are an example of harmonic producing equipment, this is especially of concern.

Filters can be used to help manage this. Filters are designed for specific frequencies and systems impedances meaning that they require extensive design and may not be robust to changes across the lifetime of the scheme. Even within a wind farm the possible number of system configurations given different combinations of the wind turbines and collector array strings can be very large and any combination could cause an unwanted resonance.

To date, the focus of harmonic analysis has been on thermal aspects of 20-minute averaged scales of harmonics imparted upon the onshore system and their mitigation. Increasingly, however, harmonic burst frequencies and their magnitudes lead to perceived impacts upon control systems, and the integrity of submarine cables which at present are unclear in mechanism and long-term impact. Innovation in this area would appear prudent.

5.3.2.2. Stability

By using HVAC, the offshore network would still be coupled from the mainland network. In the introduction we note core stability considerations. Risks to offshore network stability relate to:

- Inadequate capture of the range of operating states the offshore network is expected to operate across.

[45] Xiang, X., M. M. C. Merlin, and T. C. Green. "Cost analysis and comparison of HVAC, LFAC and HVDC for offshore wind power connection." (2016): 6-6. https://spiral.imperial.ac.uk/handle/10044/1/30859

- Inadequate range of control functionality to capture range of intended purposes the integrated offshore solution must meet.
- Inadequate specification of plant and associated protection design such that protective actions impinge and substitute for control action across credible operational conditions.
- Incorrectly designed control responses driving control system hunting and interaction.
- Inappropriately defined hierarchies for control and protection action.
- Inadequate resilience and testing of overarching control approaches across multiple devices.
- Inadequate modelling or associated data exchange informing the operational envelope and control tuning of designs.

In ensuring offshore stability to onshore system considerations, risks arise where:

- Overly rapid recovery of reactive or active power is required in an area of the network where inertia and Short Circuit Level ('SCL') are both weak and as such the measurement paradigm is degraded. In these cases a prioritisation of reactive power over an acceptable period of time to stabilise this measurement must be balanced with an acceptable recovery of active power to a depressed frequency, within Rate of Change of Frequency ('RoCoF') and other frequency magnitude bandwidth tolerances of the control systems.
- Where SCL is low and a voltage depresses multiple ends of an interconnected offshore solution, ensuring an appropriate balance of power recovery at each end is viable together with stabilisation via power oscillation damping.
- Multiple converters of similar scales or control properties emerge with potentially competing responses to voltage and or frequency disturbance.
- Conditions arise unusual to the normal operation of the transmission system where conventional stability limits are met but the instantaneous change of voltage angle impacts conventional converter tracking and normal function.
- Where low SCL gives rise to power quality background levels for which superposition of harmonic burst effects, temporary over voltage and transient unbalancing of the network may disturb converter tracking and impact withstand.
- Low SCL effects on onshore transmission protection leading to maloperation of digital protection devices in response to the unanticipated effect of converter-based fault current for which settings did not envisage.

A common denominator in resolution across all of the above areas is the deployment of a control strategy known as Virtual Synchronous Machine control, as discussed more fully in concept and benefit within the ESO's System Operability Framework report and within GC0137 specification[46]. The deployment of a VSM approach for offshore can occur on two levels:

1. Partial VSM- this control strategy operates the onshore converter in a grid forming mode such that it is a voltage source behind a defined impedance. During any voltage disturbance the power across interconnected areas of the transmission system in GB may be altered to stabilise voltage and angle without driving a longer-term inertia benefit. Such an approach requires extreme care in the setting of HVDC control philosophy but is in principle achievable and equates to a near immediate power oscillation damping control.
2. Full VSM- this requires either a provision of inertia offshore by operating the wind turbines in a grid forming mode, deloaded against power available at that time, and reversing the control philosophy such that offshore zones are grid following and onshore grid forming, or by introducing short term storage into the onshore converter design or finally via a hybrid onshore control incorporating a storage device. These later two options would appear most practical over an otherwise potentially costly deloading of wind, greater HVDC system complexity and widespread disruption of offshore wind to support transitions between the normal and inertia supporting control approaches to realise such production.

Whilst a number of stability-supporting technologies are available from standalone power electronic devices there remains considerable opportunity for innovation on optimal forms of HVDC oriented VSM, which may influence future converter topology as well as specification onshore. Given the cumulative scale of onshore converters playing a future role in integrated offshore, failure to realise appropriate stability supporting solutions would not only represent to a lost opportunity, but also risk adding to the overall resultant onshore stability requirement.

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[46] https://www.nationalgrideso.com/industry-information/codes/grid-code-old/modifications/gc0137-minimum-specification-required

5.3.3. Power Flow Regulation

AC power flow naturally splits across parallel lines based on the relative impedance of the parallel lines, therefore if an offshore HVAC route parallels an onshore route then the power flow would naturally split across them. Within GB and elsewhere uncontrolled flows have been known to cause overload, voltage and stability issues. Given that an offshore route is likely to be of a much lower rating than its onshore counterpart it is foreseeable that some of these issues could occur. To manage these issues, FACTS devices such as series compensation and quadrature boosters would need to be introduced. These devices in turn increase overall system complexity and can have stability and operability challenges.

5.4. HVDC Specific Considerations

5.4.1. Technology Barriers

5.4.1.1. Interoperability and Standardisation

There is a lack of standardisation across HVDC projects, currently each one is designed independently and there are no standards available that would readily ensure compatibility across schemes which would be a fundamental requirement for creating a meshed grid. As an example, there are not a standard set of HVDC voltages defined as there are for HVAC systems.

Across the industry steps are being taken to address this shortfall with multiple projects and industry bodies looking at this challenge. Relevant standardization groups include: CENELEC TC 8X/WG06 HVDC system aspects; IEC Vocabulary; Cigré SCB4 DC systems and power elec.; IEC TC115 HVDC transmission; IEC TC95 WG on DC protection; IEC TC57 Information exchange; Cigré JWG B4/A3.80 HVDC Circuit Breakers; IEC TC17 HV switchgear; CIGRE C4.49 Multifrequency; and IEC TC88 Wind Energy generation systems.

Within these working groups there is a focus on functional specifications, this allows for the integration of future developments on the technologies.

5.4.1.2. Supplier Availability

World leading manufacturers who can provide HVDC Converter solutions for offshore application have their commercial industrial ends available in GB, such as Hitachi ABB Power Grids, Siemens and GE etc. Since the introduction of HVDC Light by ABB, which is based on the VSC-HVDC technology, more than 20 projects have been commissioned for commercial operation or are under construction. Siemens has its MMC technology based HVDC PLUS system been installed. GE (Alstom) has its HVDC MaxSine.

Similarly, cable suppliers with HVDC capability would be available in the UK. As with the converter manufactures there isn't a huge number of suppliers. Between the different suppliers there is a great disparity in the ratings offered and the experience of HVDC projects.

A further consideration relates to engaging and developing the Global supporting GB interconnected offshore. Companies such as SGCC and Toshiba, Mitsubishi, Hitachi to name a few can potentially support the range of assets required. Whilst European manufacturers have greater familiarity in meeting GB standards, all manufacturers will be learning in how to support these and other inferred requirements offshore as integrated offshore designs and control increase in scale and opportunity and as such this may represent an opportune time for further engagement in this area.

5.4.2. System Integration Barriers

5.4.2.1. Different DC Voltages

The issue with different voltages in a DC system is that transformers only work with AC, this is the very thing that lead to the development of AC grids in the first place.

The lack of standardisation could lead to developments at different voltages. As the development spans many years, it could also be the case that higher operating voltages could be achievable (which would give lower losses) toward the end of the grid development. Neither being tied to a legacy voltage or being unable to connect parallel systems would be desired in a coordinated development.

Standardisation of the voltages would alleviate the issue with parallel systems with slightly different voltages. This would require cross-party collaboration to bring this into industry. It is important that this is done cross-border too, allowing for easier interconnection between systems.

Failing standardisation and for the outstanding issue of technology developments DC/DC converters could be used[47]. An on-going CIGRE working group entitled "B4.76 DC/DC converters for HVDC" is currently reviewing the state of this technology. The current draft of the brochure highlights that one of the most promising converter topologies, the front-to-front modular multilevel converter would be fairly easy to build today. This is because it can be built using existing standard VSC-HVDC components. The converter is formed by two HB MMCs connected through a 50 Hz transformer. The converter would be costly to build and have large physical footprint. One of the main research directions nowadays is to increase the internal AC frequency to 200 Hz or above in order to make the submodule capacitors and the reactors substantially smaller. The main technical challenge of this development is the lack of experience building multi-hundred megawatt-scale transformers of frequencies above 50 or 60 Hz. The main purpose of the DC/DC converter would be to act as a transformer between the two HVDC systems of similar voltages; however, the DC/DC converters could implement a series of useful additional features such as: blocking DC faults between the two systems, controlling the power flow of the HVDC system, providing galvanic isolation for independent earthing arrangements, etc.

5.4.2.2. Mixed Converter Technology

Combinations of converter technologies could, and have been, used to realise these solutions. By using LCC technology you can simplify the control and can have lower losses. In Denmark and Norway, ABB, implemented concept of LCC combined with VSC bipole in the Skagerrak retrofit[48]. The main benefit here is to get the reactive power control from the VSC part and combine a comparatively lower cost technology (LCC) to transfer bulk power. On the other hand, the new project in China the WuDongDe 3-terminal HVDC system, which is under development, should combine a rectifier LCC station and two inverter VSC stations[49]. The challenge for multi terminal LCC is however:

- Control: Existing LCC meet a different and more limited control requirement under the Grid code. Under the ENTSO-e HVDC code all HVDC projects irrespective of application are required to meet equivalence performance across fault ride through, voltage regulation and performance which an LCC cannot meet. As such connection of offshore wind to a new or existing LCC would not meet grid code and attract additional assets if it was used; an example of this being the Malaysian, Newfoundland and Georgia deployments of LCC of cumulative capacity approaching 6 p.u. of the HVDC rating.
- Specification: LCC solutions drive unique converter transformers to complement the converter and DC circuit design. Modifying the design introduces a potential asset replacement requirement requiring valid performance across a greater range of operating conditions including the outage of the offshore connection.
- Complementing the function of the grid forming converter offshore: The LCC has a more limited HVDC voltage regulation capability when interfacing to a weak HVAC system, as it needs to act within the limits imposed by its commutation. Where a VSM is applied in grid forming mode its function or that of the LCC will be impacted by the fundamental incompatibility of the controls compromising onshore or offshore stability or both.
- Supply and performance: Within the PROMOTioN project the option of DRU offshore supported by a grid forming wind turbine offshore was extensively considered in specification and simulation of performance. In performance aspects and specification this option was found to be more limiting, requiring of specialised design and of low materiality in comparison to the more mature VSC-HVDC solutions available and more flexible today.

We would therefore consider this area to be of limited further innovation opportunity.

5.4.2.3. HVDC Grid Protection

In Europe HVDC grid protection has been achieved by means of HVAC-side breakers in a non-selective philosophy meaning that a complete HVDC system is removed from service for a HVDC fault. Moving to an integrated HVDC network this would no longer be an acceptable loss to the system. In Germany, FB converters are to be used for a future project and there is experience in China of creating HV grids including DCCBs.

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[47] T. Lüth et al., "Performance of a DC/AC/DC VSC system to interconnect HVDC systems," 10th IET International Conference on AC and DC Power Transmission (ACDC 2012), Birmingham, 2012, pp. 1-6, doi: 10.1049/cp.2012.1971. https://ieeexplore.ieee.org/abstract/document/6521270

[48] https://new.abb.com/docs/default-source/default-document-library/skagerrakwhitepaper.pdf?sfvrsn=2

[49] https://www.rxhk.co.uk/corporate/news/rudong-offshore-wind-power-hvdc/

HVDC grid protection philosophies and the building blocks (such as DCCBs) to create these are ready to use however the choice needs to be made through standards and codes to define which of the many options could be applicable to GB. In saying that they are ready, it is important to differentiate between the functions of DCCBs which 1) onshore have had proven application in limited roles with 2) DCCBs within offshore collector hubs, and offshore meshed arrangements where application is more limited (and installation costs high). Across these areas of EU funded research project PROMOTioN, testing and simulation has delivered an enhanced technical maturity reflected in increased TRL of DCCBs.

The choice of protection philosophy will have fundamental impacts on the design of the system which is why, even if HVDC grid protection isn't required at the initial stages, the choice needs to be made early. It would be possible to use a philosophy where converters can offer HVDC fault blocking capability, if required, and where DCCB(s) could be used to separate different zones in order to limit the largest possible loss caused by faults. It has been argued that switchgear without breaking capabilities could be used to isolate the faulted conductors once the grid voltage was very low. With very fast coordination mechanisms in place, this could enable resuming partial operation very soon. This would require an understanding of what is acceptable to the HVAC system for a temporary loss of infeed. It also means that FB converters would need to be used in the development of the grid from the very beginning if such protection philosophy is adopted. Alternative approaches would require a different type of converter and different specifications of switches.

5.4.3. Power Flow Regulation Barriers

5.4.3.1. Parallel Onshore HVAC Lines

Control of power flows across parallel HVAC and HVDC lines would need to be considered in the design. Where AC power flow naturally splits across parallel lines based on the relative impedance of the parallel lines, a HVDC link would simply sit at a given value until changed. This is especially critical in HVAC fault conditions where flows can change very quickly. HVDC circuits can enhance the system resilience more than a similarly rated HVAC reinforcement because of the way in which HVDC transmission can be controlled but if not appropriately designed has the potential to exacerbate overload and stability issues.

There are existing HVDC schemes that operate in parallel to HVAC lines. For the 2 GW INELFE project between Spain and France they have developed an HVAC line emulator where the HVDC line is automatically dispatched based on the flows on the HVAC line. For the Caithness-Moray scheme in the North of Scotland, an emergency power control scheme was developed whereby critical scenarios were identified and pre-programmed power dispatch fast ramping is initiated automatically to avoid system instability and a slower acting automatic power order limiter ('APOL') is used to manage local HVAC overloads. In both these cases local measurements combined with extensive offline analysis was used to inform the design.

5.4.3.2. Parallel HVDC Lines (connecting the same HVAC island network)

In this instance the control of each of the HVDC links would need to be coordinated. The Johan Sverdrup HVDC project in Norway is the first multivendor HVDC system in grid forming operation. The project comprises parallel operation of two symmetrical monopole HVDC links each built by different manufacturers (ABB and Siemens).[50]

5.4.3.3. Parallel Lines in a Meshed Grid

For parallel HVDC lines within an HVDC grid the power would naturally split across parallel lines based on their relative resistances causing similar potential overload and control issues as those faced on HVAC networks. Interline HVDC power flow controllers or current flow controllers are devised as the HVDC equivalent of FACTS. They are converters that inject voltages of few kV in series with HVDC lines. The purpose of these converters is to control the loading of the HVDC lines in meshed HVDC systems and increase the controllability of the power flow. A few topologies can be found in the literature[51]. Other active devices on the network, such as DC/DC converters, could also be used to provide this functionality.

50 RTEI (2020). Multivendor HVDC grid development. A first TSO and manufacturer experience. https://hvdcsquare.com/wp-content/uploads/2020/05/RTEi-HVDC-webinar-second-session-May-28-2020.pdf

51 - C. D. Barker and R. S. Whitehouse, "A current flow controller for use in HVDC grids," 10th IET International Conference on AC and DC Power Transmission (ACDC 2012), Birmingham, 2012, pp. 1-5, doi: 10.1049/cp.2012.1973. https://ieeexplore.ieee.org/abstract/document/6521272

- N. Deng, P. Wang, X. Zhang, G. Tang and J. Cao, "A DC current flow controller for meshed modular multilevel converter multiterminal HVDC grids," in CSEE Journal of Power and Energy Systems, vol. 1, no. 1, pp. 43-51, March 2015, doi: 10.17775/CSEEJPES.2015.00006. https://ieeexplore.ieee.org/abstract/document/7086155

5.4.4. Other Barriers and Considerations

5.4.4.1. MITS via Boot Strap Tie-ins

"Bootstrap" connections are where an onshore transmission owner have to date developed offshore HVDC parallel routes in order to support the onshore systems capacity and performance, examples being the Western LCC-HVDC project between Hunterston in Scotland and Connah's Quay in England across the Irish sea, and the Caithness-Moray VSC-HVDC project between Spittal in the far North West of Scotland and Blackhillock further south across the Moray Firth. A natural question when building an HVDC grid in the North Sea would be to land the generation / interconnector at an HVDC bus created for a bootstrap or avoid a dedicated bootstrap by utilising offshore capacity in a co-ordinated way. This could reduce the number of onshore developments required which could reduce the overall impact on the local communities as well as reducing the overall system cost.

A significant factor in the sizing of interconnectors and grouping of offshore wind developments is the largest single *normal infeed loss risk* for which the GB transmission system is secured. This is the largest loss of real power (MW) that is allowed following 1) a planned outage or a fault outage of a single HVDC converter on the onshore or offshore platform 2) planned outage of any single section of busbar or mesh corner as per Chapter 7 of the SQSS regarding connection of offshore generation. As of April 2014, the *Normal Infeed Loss Risk* is 1320 MW.

An issue with combining the two is that as an embedded link would not normally be subject to the normal infeed loss risk constraint. As bootstraps simply move power within the same system loss of an HVDC bootstrap can be treated like the loss of any traditional piece of transmission plant. Therefore, the requirement to allow for integration of offshore wind could have a significant impact on the fundamental design to account for mitigation of loss of infeed risk depending on the ratings being considered.

From a network planning perspective, without encountering the risk that the top end of HVDC circuit capacity is uneconomic as a result of not actually adding to boundary transfer capacity (by becoming the critical fault in boundary analysis), sub-dividing a bootstrap rating into separate links does not improve boundary capacity. Redundancy in the HVDC configuration does however have the potential to improve availability and so reduce congestion but the benefit of this against increases in cost would need to be investigated.

However, where boundary capacity can be uplifted by utilising capacity in the offshore grid developed to connect offshore wind then it could reduce the required capacity of the bootstraps to be created or remove the need for a dedicated new link entirely.

Where an offshore bootstrap is required it could still be possible to integrate wind with a higher rating than the *Normal Infeed Loss Risk.* Taking a point-to-point bootstrap as an example where power generally flows from point A to point B. For wind to be connected by an HVDC link landing at or near point A the land converter could be saved for the wind farm by connecting at an HVDC bus, this could also allow the reduction in rating of the point A bootstrap converter if the windfarm was part of the needs case. For wind to be connected by an HVDC link landing at or near point B the land converter station could be saved for the wind farm by connecting at an HVDC bus, since the HVDC cable is the limiting technology the point B converter could be rated for the combined bootstrap and wind farm capacity. Solutions using meshed substations on or offshore to distribute connection capacity and interconnecting onshore network capacity could be used to limit these risks and this would naturally drive an integrated offshore network could be considered. The amount of wind that could be connected like this would need to be limited to still comply with the SQSS. With the introduction of HVDC protection, windfarms with combined ratings above the *Normal Infeed Loss Risk* could be connected at both point A and B as described. Similarly, a mid-point HVDC bus could be introduced (as with the CMS link). The counterfactual arrangement to the bootstrap example would require more modular converter station design and space provision for expansion as part of planning.

5.4.4.2. Supply Chain

The ability of the supply chain to deliver offshore networks in the UK could not only limit the ability of the UK to benefit from the development of offshore renewables, but it could also constrain the ultimate level of development. Supply chain constraints are inevitable given the relative scale of potential development and the supply chain elements shared between onshore networks and evolution of the offshore wind markets in Europe, Asia and North America.

There are a small number of manufacturers making HVDC converter technology and an equally small number of HVDC submarine cable suppliers in Europe. Some components are manufactured in the UK these European suppliers operate in a global market with manufacturing facilities both within and outside of Europe to service local markets.

In order to preserve a supply chain for the UK, government action will be required now to promote investment in factories and supporting infrastructure. Remembering the UK will be competing in a global market. The development of the supply chain market for the UK will need to be driven by practical engagement with the global supply chain to provide a tangible "line-of-sight" from project definition through to planning, delivery and ultimately offshore network optimisation.

The investment lead time for a new cable factory is about four years and 2 years to extend an existing facility. Investments must therefore be made ahead of confirmed supply contracts for specific projects. Investment costs for an export cable manufacturing facility are higher than for an array cable facility. The supply of offshore HVDC cables is constrained and there is less competition than in the onshore cable market. Offshore cable manufacturing facilities are typically located on the coast due to the need to transport cables by sea. Overseas manufacturers, particularly those in Asia, may seek to set up manufacturing facilities in Europe to avoid the high cost of transporting cables and to gain better access to the UK and European markets. Investment in the UK as the largest market would be a logical decision.

An offshore HVDC network in UK waters could stimulate UK investment in new component manufacturing capacity for HVDC converters. Component manufacturing investment decisions are based on the global demand for electrical systems or where there are centres of technical excellence. Presently, the UK market is not large enough to influence suppliers' manufacturing strategy.

There has been no UK fabrication of HVDC substation platforms and foundations. Suppliers have been mainly European. Fabricators of HVDC substation platforms have suffered delays and significant cost overruns. The UK has limited fabrication capacity for HVDC structures and further investment may be required in facilities if structures are to manufacture in the UK.

The UK offshore oil and gas sector has sustained a supply base for offshore platform construction. This provides strong expertise and its availability to the offshore renewables industry is growing but it is highly dependent on the demand from the oil and gas sector that still operates with high margins. Suppliers with expertise in oil and gas platforms, with further investment could be used for HVDC offshore substation platform fabrication but the large size of facilities needed for HVDC substation structures may be a limiting factor.

Most of the offshore substation platforms are installed on monopile or jacket foundation using a floating crane vessel with a lifting capacity greater than 2,500 t. These heavy-lift vessels used are regularly used in the oil and gas sector and are in short supply, which may impact on project schedules. Options to overcome such issues is move to modular (lighter) structures that require lower crane lifting capacities and floating self-installing designs that do not require the need for a heavy offshore lift.

Within the last five years the major cable suppliers have commissioned new cable laying ships to be built to enable larger cables to be laid in longer lengths. The ability to lay more than 100 km of HVDC cable in one campaign is highly beneficial and enables more projects to be installed in one season. The bigger vessels are required to lay heavier cables in deeper water therefore more of these vessels are required. The cable factory output parameters are sized for the largest laying vessels and with the arrival of new vessels capacities have increased to between 10,000-17,000 t. A vessel's ability to cope with unfavourable weather conditions is a compromise as a flat bottom hull shape is required for shallow water laying and these vessels are not suitable for bad weather. Apart from the cable suppliers, other cable laying vessels are owned by installers and can carry capacities of between 3,000-7,000 t.

Noting the impact that an increased offshore asset base would represent onshore, ensuring that onshore technology is sensibly minimised is critical. HVDC substations occupy increasing area with scale, which can be minimised by the reduction of ancillary assets such as filters, smoothing reactors and unconsolidated valve halls. Bipole arrangements have the advantage of reducing the footprint that two separate symmetrical monopole arrangements represent. Incorporating approaches used offshore may also lead to space efficiency but have trade-offs in visual amenity. Limiting the locations across which these sites are required, together with minimising cable related construction and ongoing disruptions can address these considerations.

5.5. Other Technology Barriers

Other technology barriers as identified in the TRL assessment are detailed in Section 3.2.6.

5.6. Technology Neutral Barriers

5.6.1. Gas Insulated Switchgear

GIS has the potential to reduce the onshore and offshore installation size requirements regardless of technology which would in turn reduce the cost and impact of the installation.

An ongoing issue with GIS is that SF_6, the gas commonly used, has become known to be a potent greenhouse gas therefore due to its potential environmental impact there is a move away from its use. Alternative gases are coming onto the market however existing vendor efforts have understandably focussed on the existing challenge of legacy quantities of HVAC GIS and their management and not the looming offshore challenge that HVDC may present, particularly should over the horizon to 2050 ambition to deploy GIS converter technology and GIS based HVDC meshed substation technologies progress.

There has been some interest in developing gas insulated valve halls for HVDC, which would reduce the volume of the valve-hall. The valve hall takes a large space in existing VSC stations. Of course, similarly to the DRU concept, this concept would require the submodules to be left untouched for a long period of time. This would require a very robust and reliable hardware design, which is a greater challenge in VSC technology than it is in a diode-rectifier unit.

5.6.2. Offshore Platforms

These incur a large percentage of the total cost of building offshore transmission assets (be they AC or DC). It would be worth reviewing what research is taking place in this area and providing opportunities for possible future developments. For instance, by considering the differences in offshore platforms in existing offshore transmission projects, it was found that the HVDC has larger footprint than HVAC. It is also found that the "power density" has not improved very much (since the first like in Borwin-1 was built) suggesting that there is a possibility to improve this and reduce costs.

5.6.3. Storage

Fundamentally the deployment of long duration storage offshore with appropriate control could lead to the smoothing of wind output leading to more dependable power production at lower overall magnitude. Whilst this offers the potential for lower rated transmission corridors offshore, the effect of storage on the HVAC solution would limit cyclic rating capabilities available on cables by the greater constancy of power flow thereby limiting the overall saving of these options. Storage would also have the potential to modify SQSS and other year-round load factor considerations and as such both control and distribution of the storage across designs and power system boundaries would become critical.

Short-term storage whether integrated into the offshore converter, or separately could be utilised to support a wider range of operating conditions within an offshore AC decoupled network as supported by one or more HVDC links. This approach may have the ability to increase the resilience of the AC island with increased inertia and short circuit level to support fault ride through offshore. However, this (as would a synchronous condenser solution offshore) would prove costly, need careful distribution within that network and be both maintenance and offshore asset intensive in its nature such that the scale of investment would be unlikely to justify its benefit.

By its very nature storage offshore, using currently available technologies is space and weight intensive upon the offshore design. As such it is more efficiently deployed onshore. Within onshore deployment, an aforementioned benefit may relate to stability supporting use. The storage device could also streamline and deploy black start solutions within that offshore network.

A final consideration for the practical deployment of storage would be within the converter arrangement itself- this would likely drive a FB converter arrangement in order to limit the duty upon the DC choppers installed on the relevant HVDC circuit. This and hybrid storage control philosophies with HVDC are potentially beneficial areas for further research.

5.7. Regulatory framework for Transmission

5.7.1. Technical Rules

Each permission that has been granted to carry out one of the prohibited activities (under the Electricity Act), is subject to a range of specific conditions. Key technical rules in respect of transmission are set out in the Security and Quality of Supply Standard (SQSS) and the Grid Code which provide a minimum framework for the planning, operation, performance and security of the transmission system in GB and within its offshore waters.

All proposed design options that we have developed for this project meet the existing rules. However, it is noted that the current rules do not define specific requirements for integrated offshore networks. This assessment is underpinned by an assumption that in principle, the design of the offshore network should not compromise transmission system performance and security of supply delivered onshore.

5.7.1.1. Security and Quality of Supply Standard ('SQSS')

The SQSS defines the minimum criteria that must be applied when planning and operating the GB transmission system. Compliance with the SQSS is a condition within all types of transmission licences. Minimum criteria applicable to the design of transmission system:

- Onshore - generation connections are set out in SQSS chapter 2;
- Onshore - demand connections are set out in SQSS chapter 3;
- Onshore - main interconnected transmission system is set out in SQSS chapter 4; and
- Offshore - generation connections are set out in SQSS chapter 7.

To date, offshore wind farms have connected to the transmission system via dedicated connections that have not paralleled the integrated onshore transmission system. Whilst our conceptual designs meet the minimum requirements for offshore generation connections that are set out in the SQSS, the existing rules may not be sufficient as the volume of offshore wind farm capacity increases. By 2050, the level of offshore wind generation capacity is expected to be a dominant source for meeting year-round demand levels. Based on historic experience, this type of significant change would be expected to trigger a review of the existing technical rules (including CBA of the expected year-round impacts) which may lead to requirements for changes to the SQSS to be implemented.

The impact of parallel offshore integrated solutions across onshore transmission boundaries has been considered as part of this assessment from the limited perspective of supporting offshore growth whilst minimising onshore impacts. Offshore system design options as part of a holistic combined onshore and offshore design approach, may provide scope for more extensive benefits but are expected to require a review of existing framework rules. For example:

- The contribution or otherwise of offshore generation or planned offshore network flow to onshore interconnector allowance capacity considerations.
- Extension of onshore boundaries into the offshore system in a coherent manner to capture the opportunity of onshore and offshore capacity planning.
- Consideration of load factors of wind on a regional basis capturing the increased geographic scale and diversity of future GB offshore wind.

A further extension of the boundary capacity and security discussion would require a review of the impact on control system resilience. Within the existing GB onshore transmission system, there is a limited but increasing dependency upon wide area control schemes which inform rapid action across a variety of controllable assets across the network to manage power flow or address network voltage regulation or stability issues. Integrated HVDC solutions used for the connection of large capacity offshore network development connections, are entirely dependent on the correct functioning of such wide area control philosophies across multiple devices. There appears to be a need to develop specific standards of robustness for control system requirements and philosophies and to define their treatment within boundary capacity and other SQSS relevant analysis.

Minimum criteria for HVDC interconnectors, and their local and wider capacity treatments are not explicit within the SQSS. Whilst this deficiency may have been manageable within the context of discrete interconnector connections, it presents challenges to the efficient delivery of hybrid interconnector and offshore designs, as the operation of the HVDC side of these arrangements and its associated capacity requirements is particularly unclear. We recommend that a review of the SQSS is undertaken to develop and propose specific minimum planning criteria that distinguish between offshore wind output as serviced by an interconnector and residual flow to or from an external network for:

- Specific "hybrid" circuits; and
- integrated offshore networks connecting both generation and interconnectors.

The maximum loss permitted for a radial connection onshore (defined via the infrequent infeed loss limit of 1800 MW) is not the same as that permitted for a radial connection loss offshore (defined via the normal infeed loss limit of 1320 MW). This definition difference has limited the scope of the concept design building blocks that can be combined to identify integrated offshore HVDC network options and their associated cable and converter capacity scales. An equivalent onshore HVDC converter would not be subject to these same limitations and in particular we highlight that:

- It is unclear from our technology analysis that there is a reason for such a difference. As such we would recommend a review of this area of the offshore standard to be appropriate to allow any artificial limitations to efficient high capacity future connections to be removed.
- Presently a single cable supplier does not exist to support the benefits of a higher maximum offshore loss level of 1800 MW, but that within the next decade, further supply and in-service experience with such cables may make these higher capacity options more attractive and practicable.
- Within the context of fast protected HVDC multi terminal environments, an ability to isolate a lost generator and restore the remaining generation in timeframes less than 140 ms is possible. As such the traditional definitions of "circuit" and/or "loss" may need to be reviewed, to avoid missing the opportunity of acceptably managing multi terminal solutions connecting greater than 1320 MW, or indeed higher than 1800 MW on a single HVDC circuit where elements off it may be restored within 140 ms to contain the overall loss at that point.

Transitional options including co-location of energy storage solutions at onshore substations could facilitate compliance of offshore transmission designs rated above the current 1320 MW limit.

5.7.1.2. Grid Code

Currently, the Grid Code set out a range of minimum technical requirements which are relevant to offshore generator connections which are either required to be demonstrated at the onshore GB transmission system connection point or have the option to be separately demonstrated offshore. The Grid Code requirements currently makes no distinction between offshore and onshore frequency and voltage ranges of control or tolerance and present limited obligations for the demonstration of offshore control and regulation. This has been possible given that in every case to date the connection of offshore transmission to the GB system has been via a generator-build approach where the technical performance and acceptable operational envelope of dispatch of the offshore network to support both the generator and the onshore transmission system have been subject to parallel levels of scrutiny via the offshore tendering process and the generators' own compliance process. Increasingly and as recognised across Grid Code modification proposals[52], more extensive data exchange and associated analysis across parties will become increasingly critical to support not just the increased volume of converter-based connections offshore but also onshore.

Going forward, in both integrated HVAC and HVDC, onshore resilience within the Grid Code becomes subject to the more complex interplay of multiple devices owned across OFTO(s) and multiple generator projects and the need for assets to perform collectively in an acceptable manner to support the onshore network. Given such networks would no longer be wholly radial in nature, but supporting the integration of the onshore system, the Grid Code minimum requirements would need to extend beyond purely connection consideration, to the integrity of the overall GB systems.

HVDC as with all converter-based connections can offer highly flexible solutions but may be exposed to vulnerability if the:

- Operating states of the technology are unclear or modified significantly over time;
- Strength of the network (its inertia, short circuit strength and other relevant factors) is too low; or
- Potential for interaction with other fast control or mechanical responses is not clear.

HVDC leads to a "decoupled" offshore HVAC system where the frequency and voltage for the offshore network do not naturally follow the onshore system but occur as a result of the interplay of control systems- there is no natural frequency or voltage regulation in place, nor inertia. As such voltage and frequency regulation is fundamentally dependent upon the accuracy and resilience of those control systems and their underlying stability. These are aspects that the existing Grid Code does not cover onshore, but may be addressed in relation to those changes proposed under GC0141[53] which is seeking to expand the extent of data exchange and compliance demonstration into areas where such control schemes become material to onshore converter based technology performance. In particular subtransient timeframes used by these control systems to within microseconds respond to events become important, as do the operation of Phased-Locked Loop forms of control which seek to measure the system over similarly fast timeframes to inform the tracking of a control scheme to the system it measures. In an offshore HVDC context this system is the controlled behaviour of a HVDC converter and avoidance of control interaction and provision of adequate damping of oscillation and short duration voltage and frequency deviation must be considered in the control designs present.

[52] GC0141 and GC0138

[53] https://www.nationalgrideso.com/industry-information/codes/grid-code-old/modifications/gc0141-compliance-processes-and-modelling

Under a "decoupled" offshore HVAC system many of the standard forms of wind turbine compliance demonstration become a function of the control environment and the onshore conditions it is subject to, that is presenting the wind turbine with different conditions (e.g. high frequency and over voltage during a fault ride through event) which are not subject to defined tests at present. Fundamentally, using current limited forms of grid forming control, and without introducing excessive over-rating of plant and apparatus offshore, it is not possible for the offshore de-coupled HVAC network to equivalently ride through an offshore HVAC fault condition. This inherently places a limit on the maximum decoupled offshore HVAC system scale, the size of monopole converter that supports it and the extent these HVAC systems are coupled together. The pertinent limit as discussed above is currently the "normal infeed loss limit" of 1320MW within the offshore requirements of the SQSS.

Within all HVDC designs- a key component of converter is the DC "chopper" a device which for interruptions of active power transfer whether due to AC or DC fault will switch in to protect the converter from damage. The DC chopper is a fast-acting energy dissipation device. As integrated networks become more extensively used the rating of the DC chopper must be established to provide necessary resilience in the given HVDC design, in order to avoid key infrastructure spines of HVDC cable to become unavailable during planned or indeed more extreme but foreseeable network situations. The specification of this device within network codes is currently unclear with risk it may be inappropriately interpreted at present. In multi-terminal and meshed applications of HVDC, multiple DC choppers are required and their basis for respective specification would also need to be codified.

The recent RTE led testing of the Johann Sverdrup project, where two different manufacturers developed HVDC connections to an existing oil and gas platform, were tested, together with the performance of overarching control schemes across the two HVDC projects, presents a potential template for evolving existing codes and testing process. The National HVDC centre has initiated a project, partnering with the ESO to develop a co-ordinated simulation and testing approach to future complex Offshore arrangements which enables at each point of the project lifecycle suitably complete and representative vendor models to be combined and overall control philosophies to be tested. This work calls on RTE's developed expertise and will seek to make proposals in this area early in the next financial year.

5.7.1.3. Changes to Technical Rules

There are defined processes for progressing reviews and modification proposals for the Grid Code and the SQSS. Any party can request a review of the specific requirements defined in the Grid Code or the SQSS. The ESO is responsible for progressing change proposals and for the submission of a final report to the Authority which may propose a change to the relevant set of technical rules. The Authority is responsible for making decisions in respect of change proposals that are submitted for consideration.

Further details of the process requirements are provided in Appendix E.

5.7.2. Legal Basis

Within the Electricity Act, a limited range of prohibited activities are defined in respect of generation, participation in transmission, distribution, supply, participation in interconnector operation and provision of smart metering services. Barriers arising from the scope of a prohibited activity defined in primary legislation cannot be addressed in full by changes to the conditions of the permissions that have been granted.

The process for introduction of new Acts (including those required to modify existing Acts) can be initiated by government and requires robust development and consultation process stages. Implementation of changes to primary legislation is subject to the availability of parliamentary time. Changes to the Electricity Act have been made and have tended to be associated with significant changes required within the electricity sector such as the introduction of the offshore transmission regime.

The Electricity Act allows for the Authority to make (with Secretary of State approval) regulations for determining who to grant an offshore transmission licence to. Regulations in the form of a Statutory Instrument ('SI') are used to provide more detail than contained in the primary legislation and are referred to as secondary legislation. Each SI requires Parliamentary consideration before if comes into effect. Parliament can either approve or reject an SI, but cannot amend it.

The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2015 define the Authority's competitive selection process for offshore transmission. The process requires an application to be made by a Developer responsible for an offshore project and the Regulations are written in terms of a single Developer applicant per application. Whilst the Regulations refer to both the Generator Build and OFTO Build options, specific process requirements have not been defined in respect of the OFTO Build option.

A review of Competitive Tenders for Offshore Transmission Licences Regulations 2015 is recommended to:

- assess potential barriers to, and
- facilitate the adoption of a coordinated offshore network approach that enables offshore transmission assets to be shared between generator projects.

The Electricity Act defines powers for the Authority and the Secretary of State to issue new, modify or remove existing permissions to carry out a prohibited activity. Permission to carry out these prohibited activities can be granted via a licence granted by the Authority or by an exemption from the requirement to hold a licence that has been granted by the Secretary of State by the issue of an order.

The Authority has granted the following types of licence:

- Generation;
- Transmission – three main types which are referred to as System Operator, Onshore Transmission Owner and Offshore Transmission Owner (OFTO);
- Interconnector;
- Distribution; Supply, and
- Smart Meter Communication.

Ofgem can propose modifications to any of the conditions defined in each type of licence. The licence modification process requires at least one stage of consultation that informs decision making. Changes to licence conditions are made by the issue of a direction by the Authority.

The Secretary of State has issued exemptions from the requirements to hold a licence in respect of:

- Generation (class and specific);
- Supply; and
- Distribution.

There is a specific provision in the Electricity Act to allow for a generator constructing offshore transmission assets (as part of the generating project) to operate those assets until commissioning is complete (the generator build option). This option has been and continues to be used frequently in respect of the delivery of existing offshore transmission infrastructure.

The Electricity Act applies within GB and its offshore waters. For any connection between the GB transmission system and a European system, an interconnector licence is required. The framework for interconnector connections is well defined. There are existing interconnector connections to the onshore transmission system within GB as well as further projects that are being developed. The framework requirements have not yet been applied for a connection of an interconnector to an offshore part of the GB transmission system operated by the ESO.

Interconnector circuits are not operated by the ESO in the same way as transmission circuits. Framework rules have not been defined for the connection of an offshore wind farm to an interconnector circuit. One option that was extensively reviewed in the EU funded PROMOTioN project was the possibility of separately categorising assets in terms of purpose (e.g. for the purpose of facilitating generation connection to the GB transmission system and those solely for the purpose of interconnection). As part of the PROMOTioN project a new "hybrid asset" asset class has been proposed to be utilised for connections which combine the functionality of cross-border interconnectors (for trading purposes) and offshore wind farm connections (for the purpose of energy evacuation)[54]. This classification aids formulation of regulatory codes and interfaces within such arrangements.

The applicable arrangements for the design, planning and operation of an integrated offshore arrangement which operates across licenced activities is not currently clearly defined. This could limit ability to realise the full potential of integration and be a barrier to the delivery of the co-ordinated and managed evolution offshore transmission infrastructure. For example, it is not clear which party would/could be responsible for the operation of a hybrid offshore transmission and interconnector circuit or whether this role could be extended to the operation of a pan- European offshore grid that may evolve in later years.

Whilst provision for generator build is currently clear within the existing regulatory framework, the provision for a collective build across generators is not. An extension of current arrangements relies on commercial and or legal instruments to allow a collection of generators to do this, given this drives a collective commitment and dependency for a given stage in an overall offshore development to be constructed. Beyond this, it is not clear how a collective delivery of a development stage that is dependent upon an earlier construction activity by another licensee generator or interconnector would be managed within the current regulatory framework.

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[54] PROMOTioN WP7 Deliverable 7.9 Regulatory and Financing Principle for a Meshed HVDC Offshore Grid, 2019, https://www.promotion-offshore.net/fileadmin/PDFs/D7.9_Regulatory_and_Financing_principles_for_Meshed_HVDC_Offshore_Grid_2_.pdf

Regulatory treatment of hybrid offshore designs including short-term storage would also require consideration. In overcoming integration barriers, we note that the delivery of short circuit strength, inertia and voltage stability requires a consideration of short duration electrical power storage to supplement the onshore performance of these offshore networks. The wider GB system would as discussed in the ESO's System Operability Framework and Stability Pathfinders, be expected to see falls of these same quantities over time as other existing conventional sources of these capability (coal, gas, oil, nuclear) decline in availability on the path to a net zero carbon future. This would result in the future GB transmission system security being more dependent on these resources associated with the integration of the offshore networks onshore.

We discuss a range of options by which integrated offshore networks may provide these forms of support within this report. Whilst it has been made clear via statements from the Authority that long-term storage represents a market activity, the short-term storage inherent in optimising an offshore networks operation to support the network in the above areas is less clear. Such storage may be integrated into the control systems and/or physical converter designs of those offshore networks to greater efficiency in many cases. From a licence perspective, the categorisation of short duration delivery of such stored energy to stabilise the onshore transmission system, but not disturb normal energy market function would provide useful clarity, whereas were it to form an excluded generation license only service would limit the range of practical providers of that capability. Existing transmission and distribution resources inherently function in this manner today (for example a transformer will naturally store and discharge energy to support the transmission or distribution systems in these timeframes). An open approach allowing Transmission, Distribution, Interconnection, Generation and Supply to explicitly deliver this capability to the ESO would both widen the pool of providers and enable the most efficient outcomes to be obtained from within that pool of providers.

As illustrated by the cases above, new areas of regulatory and legal instruments may be required to facilitate the efficient delivery of integrated offshore network developments. Were such changes not included as part of proposals for facilitate the development of integrated networks offshore, our initial views are that this:

- Would not provide a set of applicable regulatory framework rules with equivalent transparency to those that have been established under the Electricity Act to date;
- Could restrict network design options to those that fall within the current scope of the Transmission prohibited activity (i.e. between points within GB and its offshore waters); and
- Might exclude generating stations that are not situated within GB or its offshore waters from integrated offshore network design solutions.

5.8. Potential Solutions

Strategic alignment between offshore wind developments and offshore network planning processes would enable optimal sequencing and delivery of coordinated offshore transmission solutions. The approach developed across the ESO Offshore Coordination project is based on the LW scenario of the 2020 FES. The scale and pace of growth across different offshore wind regions is key driver for enable efficient development of the offshore network. Therefore, a strategy for aligning offshore wind leasing and transmission planning process will be beneficial for removing technical, regulatory and socio-economic barriers link with uncertainty around the extent of offshore generation and transmission developments.

5.8.1. Scale Trials

To overcome some of the final technical challenges and to improve the maturity and confidence in the technologies scale trails could be done or additional support to pilot projects could be given. There is a proposal where suppliers are looking for a potential pilot project where they could work together to development a multivendor solution for a multi terminal project where research money could be used to de-risk the development.

5.8.2. Optimisation of designs, their operation, control and protection

Across our integrated offshore designs, a number of conclusions can be drawn. Historically offshore transmission networks have been designed to efficiently accommodate the requirements of a single project with the option within such designs to identify the potential option for the extension of that design to accommodate new tranches of offshore wind connection. Whilst this has served initial control requirements become more complex and more extensive. These designs require control schemes which can (an indicative hierarchy is provided):

1. Resilience of all integrated networks to the single largest offshore loss that may occur across the network.
2. Regulate offshore frequency and voltage within the tolerances of offshore converter and wind turbine to avoid cascade disconnection across the entire range of normal and post fault operation behaviours the offshore system is expected to be subject to – to avoid a vulnerability to cascade loss of multiple decoupled offshore HVAC systems of windfarms.
3. Robustness in composite control philosophy of multiple devices and robustness in the design and operation of the control systems in place.
4. Discriminative and/or fast isolation and restore HVDC protection philosophies which allow status of the DC system to be quickly identified communicated and responded to.
5. Active damping controls to limit oscillatory and excessive deviations in frequency, voltage and other parameters.
6. A graded withstand philosophy of devices supporting progressive rather than successive failure mechanisms such that extreme condition responses are both predictable and obvious in progression such that operators may intervene and plan against known behaviours.
7. Record play back and monitoring enabling the management of offshore control and protection suspected maloperation where it occurs with rapid event investigation.
8. Overarching control and protection visibility; availability, functional capability, activity to provide control engineers with the clarity of how available an integrated offshore network is in practice, beyond the primary assets; and ensure the optimal balance of power flow from these assets onto the onshore system is achieved at any given point in time.
9. Wide area control enabling the above network flexibility to rapidly ramp offshore power distribution across offshore converter terminals on an onshore power system in response to onshore actions and faults.
10. Communicate onshore requirements for e.g. frequency support to the offshore system and its wind turbine resources, distribute dynamic voltage support, provide black start capability.

Key to the control principles above is noting that any control scheme is limited in how many of the above actions can ever be practically delivered in a single instance of time- the prioritisation of the various flexibilities within the conceptual design being considered are ultimately key to its robust and stable performance. As such, it is essential that across the incremental development of integrated offshore solutions the scope of the intended use of the offshore system is fully recorded and the hierarchy of controls developed mirrors that intended purpose. The testing of these controls and protections, not merely individually but in a system environment which is representative of that intended purpose is critical to gain confidence in overall actions progressively complex in nature which need to be understood on an equivalently intuitive basis over time to the principles of HVAC transmission which have served us well over the previous century.

5.8.3. Opportunities supporting operability

By 2050 the scale of intended generating capacity offshore of GB exceeds the range of onshore GB demand on the transmission system at the time. The connection of offshore in this context means:

- Onshore generation support to the onshore transmission system may be limited over significant periods of the year.
    - Existing services such as frequency support, reactive power support and black start to the GB system need to be included in the capabilities of offshore designs as these will have the potential to be increasingly be utilised in conditions where other resources become of limited availability.
- Onshore system power flow may be very low across certain periods of year as generation supply from the offshore system dominates.
    - Distribution of onshore connections of the integrated HVDC arrangements, each coming with their own dynamic voltage control and potentially other support such as fault level and inertia enables the onshore system to be equivalently supported without additional infrastructure onshore.
- Surplus power within GB may benefit being directly exported to continental Europe.
    - Use of integrated HVDC arrangements and provision for flexible extension of offshore HVDC collection to meshed European grids supports this.

5.9. Risks and Route Map

It is critical to overcoming barriers that the considerations identified in this report are addressed. Key to a successful strategy for achieving this is:

1. Pragmatic incremental development stages which are clearly defined and support co-ordination and clear focus areas across a wide range of stakeholders.
2. Future horizon opportunity scanning to ensure immediate opportunities are not lost and the consequences of themes of research and development upon conceptual designs and their component technologies are understood. Across the period to 2050 this should be a repeated activity encompassing a broader array of technology assessments as the research and supplier-based activities in this area evolve.
3. A deployment focused innovation strategy which prioritises innovation in areas which may with sufficient activity and analysis yield practical opportunities to realise efficiencies within conceptual designs and/ or new designs that can demonstrate in concept clear efficiencies in comparison to those existing options (i.e. the PROMOTioN project).
4. Supplier supported trial and deployment teamed with R&D to increase TRL and in-service experience of integrated solutions as they are developed (i.e. the EFCC project).
5. Effective Data and modelling coupled with "in-service" monitoring and validation boosting ability to deliver and integrate new integrated solutions effectively.

Proposed recommendations together with suggested actions and timeframes that would be beneficial for the development of coordinated offshore transmission networks are summarised in Table 5-1.

Table 5-1 Recommendations with necessary actions and timeframe.

Recommendation	Reason	Benefit	Timeframe realisable over	Actions necessary to overcome barriers
Review legislation to allow for integration of offshore assets	Current legislation (primary and secondary) limits the ability to truly integrate offshore grids	Connection point of interconnector could be offshore	Unclear This work would need to be initiated and led by Government (Secretary of State and/or the Authority)	1. Engage with relevant stakeholders
Update regulatory framework rules for development of offshore grids	Currently don't adequately cover	Improved shareability of offshore network assets. Clear guidance for development	Subject to consultation	1. Initiate updates to the regulatory framework rules
1320MW-> 1800MW loss offshore	Permits larger capacity integrated solutions	Up to 27%[55] reduction in HVDC assets, could potentially be realized.	Beyond 2030 where cables of relevant rating could be more generally made available.	1. SQSS change 2. Cable technology development.
Standardisation of offshore infrastructure	Permits multi-vendor & multi project development	Reduction in unit cost across multiple projects due to competitive market forces (re-design to cost) • Encourages more entrants to the market • Move away from single supplier solutions	Over next 5-10 years	1. Grid Code clarity 2. Co-ordinated process between industry, end users and standards organizations 3. Co-ordinated functional specification

55 Based on reduction in number of assets, due to higher ratings. (i.e. [1-(1.32/1.8)] *100%) = 27%

Recommendation	Reason	Benefit	Timeframe realisable over	Actions necessary to overcome barriers
Improve maturity of technology HVDC XLPE cables > 320 kV	Enable larger transferring capacity	Lower cost, wider supply chain, better thermal performance, easier installation and more compact cable for the same power rating compared to paper-insulated cables. Reduction in total length (higher voltage reduces the number of cables for the same transmission capacity), cost and footprint with same capacity compared to lower voltage level.	The technology would become mature beyond 2025 when the operating experience has been acquired, and the manufacturing process has been established amongst all the major cable suppliers.	For 400 and 525 kV XLPE cables: 1. Commercial manufacturing process 2. More operating experience For 640 kV XLPE cables: 1. Pass the qualification tests (e.g. PQ test, type test) 2. Commercial manufacturing process established 3. Commissioning and operating experience
Improve maturity of technology offshore HVDC converters ≥ 1000 MW	Permit larger size or more integrated wind farms	Economy of scale and size going from 900 MW wind farm capacity as industry benchmark to 1200 MW with ambition for 1800 MW.	By now the technology is mature and industrially deployed. By 2025 sufficient operation experience would have been acquired on 1000 MW, 320 or 400 kV converters, and 1400 MW, 525 kV converters. For converters ≥ 1000 MW, 5 years on average is considered reasonable for collecting operation experience	1. Experience in operating and maintenance (of ongoing interconnector projects at 400 kV, 1000 MW and 525 kV, 1400 MW)

Recommendation	Reason	Benefit	Timeframe realisable over	Actions necessary to overcome barriers
Improve maturity of technology DCCBs	Permit partially and full selective protection strategies, and some variants of non-selective strategy.	Fastest fault clearing within a few milliseconds. Minimized impact of a fault on the grid since the DC grid need not be de-energized (switched off) to clear the fault.	By now the technology is available. The timeline for industrial realization is dependent on market pull for the development of an offshore grid	For hybrid DCCB: 1. Final commercial design and qualification tests against industrial standards and norms (still need to be developed) 2. Manufacturing process and quality control build up For other types of DCCBs (e.g. VARC, ACI): 1. Production prototypes to be developed 2. Qualification tests on production prototypes 3. Manufacturing process and quality control build up
Improve maturity of multi-vendor, multi-terminal solutions	Allows for the incremental development of networks without being 'tied' to a single vendor	Most benefit in the coordinated design comes from eventual integration of an offshore network to which this is fundamental	Over next 5-10 years	1. Engage with stakeholders 2. Identify and support potential pilot projects 3. Experience in operating and maintenance
Improve maturity of technology HVDC GIS with SF_6	Save space for offshore platform	Up to 90% reduction in volumetric space of GIS installation, results in a 10 % size reduction of overall platform. Less footprint is created.	By now the technology is available and industrially mature.	1. Experience in operating and maintenance
LFAC technology (TRL=3)	Not recommended due to investment cost to reach TRL 9	—	—	—

Recommendation	Reason	Benefit	Timeframe realisable over	Actions necessary to overcome barriers
HVAC technology	HVAC is not favorably recommended due to distance limitations, requirement for offshore reactive compensation and increased platform size, and increased cable footprint due to number of cables	–	–	–

6. UNIT COSTS

This section provides a summary of the Unit Cost data that was provided as an input for the CBA to inform the assessment of possible offshore network design approaches. The values of component costs presented in this section were utilised to calculate:

- capital expenditure ('CAPEX'), and
- operational expenditure ('OPEX')

for different offshore network design solutions analysed within the CBA workstream.

The actual cost data were deliberately removed in this public version to preserve its confidentiality.

6.1. Assumption

The estimated costs provided in this section include cost items such as procurement cost, installation cost and project overhead cost. The procurement cost included direct material cost, labour cost, R&D cost and profit margins[56] and the project overhead cost included costs related to PM initialization/realization, surveys and studies.

Market fluctuations and location specific factors have been excluded from the estimated costs for this assessment. The cost estimation for 2020 is based on cost data from 2017, where we assumed no substantial market fluctuations. The cost data will be used for the whole project portfolio, which might consist of many projects. The cost of each project will be impacted by certain specific cost drivers such as required ancillary services, redundancy level, the scope of service contract, ambient temperatures, water depth and cable routeing. Except for offshore platforms, those specific factors for various subsystems will not be considered on a detailed project-by-project basis, instead they will be considered on an average level.

In the majority of cases, the primary focus will be target on the technical performance parameters of the components, e.g. power and voltage ratings for HVDC converters and cables, current breaking capacity for DC circuit breakers. The cost estimation will in general not differentiate among alternative implementations which offer the same functionalities and performances, for instance:

- When applied in VSC HVDC applications, both XLPE cable and MI cable can be used and have similar performances.
- Various implementations of DCCBs (Hybrid, various mechanic DCCB solutions) offer largely a similar set of functionalities.
- Various solutions of offshore HVDC platforms can be used such as jacket, jack-up and gravity based solution ('GBS').

The technologies and assumptions for each category of components are presented as below:

- HVAC and HVDC cables
    - For HVAC cables, the underground section will use three single core cables whereas the submarine section will be implemented as one three core cable.
    - For HVDC cables, we will consider two separate cables (plus and minus pole) which will be laid in parallel to connect the HVDC converter station with symmetric monopole or rigid bipole topology. A third metallic return cable will be considered if the topology of "bipole with metallic return" is selected for the HVDC converters.
    - The total cost of cables includes procurement cost, installation cost, project overhead cost and ground cost.
- HVDC Converter stations
    - We will focus on VSC HVDC (both half-bridge ('HB') and full-bridge ('FB')), the technical characteristics of LCC HVDC make it not suitable for the offshore wind integrations. Diode Rectifier Unit (DRU) was promoted a few years ago as a modularized and lower cost alternative to offshore VSC HVDC by a few market actors, however the momentum seems to be ebbing out in recent years and we are not aware of any serious attempts to push this technology to be commercially available. It is less likely that such a technology will be applied in the time-horizon of this assignment.

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[56] It is difficult to obtain profit margin for individual components; we used the aggregated profit margins from different vendors. More specifically we used the announced EBITA margins in their financial reports.

- For HVDC converters with identical technology (HB or FB VSC), the most important technical parameters are among others the DC voltage and Power Rating, we assume that converters with identical DC voltage level and Power Rating will have similar costs in terms of power electronics components.
- However, it is expected that control & protection will be more complex and converter transformers will be more demanding in bipole (both rigid bipole and bipole with dedicated metallic return) topology than their counterparts in the symmetric monopole topology. Such differences will be addressed in the cost estimation.

- Offshore platforms
    - There are several different designs of the offshore platforms for HVDC converter stations, each have different Total Cost of Ownership ('TCO') implications. We foresee that the various projects within the ESO portfolio could choose different solutions thus they have different TCO, we provide cost estimates as a range covering the three different solutions: jacket, jack-up and GBS.
- DC Circuit breakers (DCCB)
    - As a relatively new components with limited installations, the cost estimation of DCCB was done in a bottom-up approach based on our understanding of the most promising solutions (hybrid DCCB, mechanic DCCB etc).

The range of technical parameters (power and voltage rating) was selected using the "off-the-shelf" products from major OEMs, we are aware that the concept design will likely propose components beyond the selected ranges. In such case, a high-level estimation will be made based on the cost values of similar components with lower ratings.

6.2. Unit cost data

In this section, we present the unit cost data for major components. The cost then is shown with different cost elements with their corresponding percentage. The cost elements include the cost of equipment, installation and transportation, civil works, project management, right of ways, risk contingency and profit margin.

OPEX cost is also provided for each subchapter below. OPEX cost for AC and DC systems include periodic maintenance of equipment which typically includes the following tasks:

- Scheduled maintenance of the foundations and structure
- Scheduled maintenance of the topside and electrical equipment
- Scheduled maintenance of the electrical equipment at the onshore substation
- Scheduled maintenance of cables

Cost typically included in OPEX are labour, spare parts, consumables, supply and accommodation vessels, crew transfer vessels or helicopter costs if applicable, travel expenses for staff and overnight accommodation, waste disposal and management.

6.3. Cost reduction potential

The unit cost data provided in section 6.2 reflect the 2020 cost levels. The offshore power transmission technologies, especially the HVDC-related, are still under active development, and we expect that the cost level will decline with time. In this chapter we present the results from our modelling of cost reduction potential.

6.3.1. Methodology

Cost of products can be split into the cost that vendors spend to develop, transport and install the product, plus the risk contingency and the profit margin the vendor add to make money. This is also the rationale we have used to project future cost level of AC and DC components. The cost that a developer spend on AC or DC components consists of three parts: Vendor cost plus the profit margin and risk contingency vendors add onto the product.

Figure 6-1 Cost can be split into vendor cost, profit margin and risk contingency

The vendor cost consists of several sub-items, which we have defined in our model as equipment cost, installation and transportation cost, civil work, project management and right of ways. Figure 6-2 illustrates the cost drivers that impact the cost elements in the model. Important cost drivers are labour, engineering, energy, commodity and land cost. Labour cost considers low-skill labour that is typically used for civil work and installation, while engineering represents high-skill labour typically used for technical designs and project management.

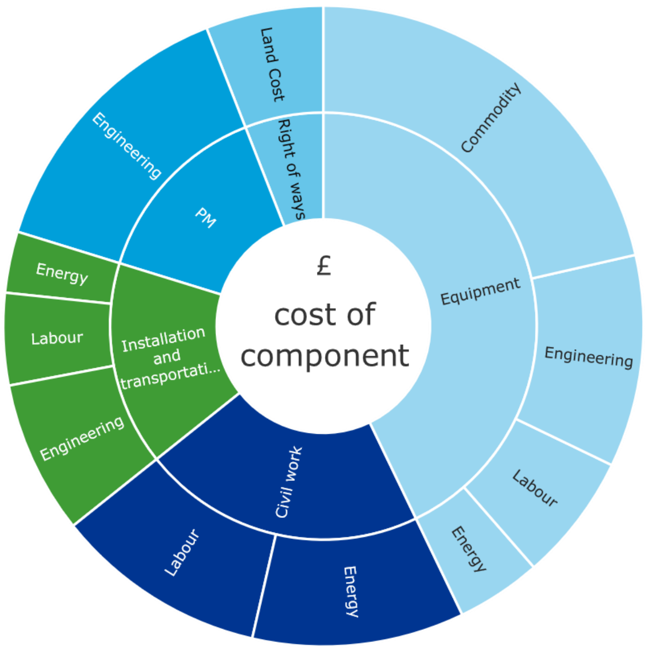


Figure 6-2 Cost breakdown illustrating the impact from cost drivers on cost elements, and hence on the overall cost

Energy accounts for the energy that is used in manufacturing, installation and transportation. Commodity refers to steel, aluminium, copper, power electronics components and XLPE, which are used in manufacturing of the equipment. The fifth cost driver, land cost, refers to the cost of buying a legal right to pass the cable along a specific route, and is only relevant for AC and DC underground cable.

The future cost of AC and DC components will depend on how each of the cost drivers develop over time. The percentage breakdown of vendor cost into equipment, installation and transportation, civil work, project management and right of ways defines the contribution of cost drivers on the overall cost. E.g., if a major percentage of the cost of a component is civil work, Figure 6-2 tells us that the development in cost of energy and labour to a great extent will impact the cost of civil work and hence the overall cost of the component. The cost breakdown is hence important in determining future cost of components in our model.

6.3.2. Assumptions on trends impacting cost drivers

In the model we have assumed that the following trends will substantially impact the cost drivers and hence the cost level of AC and DC equipment towards 2050:

- **Automation**

Artificial intelligence, robotics and other forms of automation will most likely advance at a rapid pace in the coming decades and will boost productivity. In this analysis we have assumed that the amount of labour- and engineering hours needed in production, installation, civil work and project management will go down in the next decades.

The assumptions we have used about increased productivity is based on a study performed by PWC which have identified the automation potential within different industries and across different educational levels[57].

- ✓ The study concludes that by late 2020, automation potential for manufacturing jobs requiring low education is 24% while the automation potential for manufacturing jobs requiring high education is 15%. By mid 2030s the numbers are increased to 60% and 19% respectively.
- ✓ For the construction sector in late 2020s, automation potential for jobs requiring low education is 16% and automation potential for jobs requiring high education is 10%. By mid 2030s the numbers are increased to 48% and 12% respectively.

- **R&D hours**

Many HVDC components are currently under active development and the extent of engineering hours that are involved in developing such products (R&D) will go down as technology gets more mature. In our model we have hence assumed a potential to reduce engineering hours for all DC components, except from cables which are assumed to follow the opposite trend with a need for large future R&D work to develop voltage and power ratings. AC components are mature technology and no change in R&D and hence engineering hours is expected.

- **Energy mix**

Production of equipment, installation, transportation and civil work requires energy. Towards 2050 we expect to see a considerable change in the energy mix which will not only have a positive influence on emission level but also on cost level as increased electrification reduce the overall use of energy. In the analysis we have tried to reflect the change in energy mix. We have assumed that electricity will replace a significant part of fossil fuel used in production of equipment and in civil work. For installation and transportation, we assume that fossil fuel will still be needed to transport and install the heavy equipment.

- **Unit price of commodities, labour and engineering**

We have identified six commodities that are relevant when discussing the cost development of AC and DC equipment: Aluminium, copper, steel, power electronics, XLPE and oil. World Bank provides price forecast for aluminium, copper, steel and oil towards 2030 and is used in this analysis. World bank forecast that the unit price for aluminium, copper and oil will increase in the future, while the unit price of steel will decrease[58]. For power electronics we have assumed decreasing unit price[59] and for XLPE we have assumed constant price as we don't have a price forecast. Unit price (wage) for labour and engineering hours is also assumed constant in our model.

- **Profit margin and risk contingency**

For unmatured technologies such as DC components we will likely see a trend towards a decrease in profit margin and risk contingency with increased competition and experience. For mature technologies such as AC components a decrease is also expected, but more moderate than for DC components.

57 https://www.pwc.co.uk/services/economics-policy/insights/the-impact-of-automation-on-jobs.html

58 http://pubdocs.worldbank.org/en/477721572033452724/CMO-October-2019-Forecasts.pdf

59 https://www.electronics-sourcing.com/

6.3.3. Result

Based on the methodology and assumptions explained in section 6.3.1 and section 6.3.2, our model calculates the projected development in cost for HVAC and HVDC components. Figure 6-3, Table 6-1 and Table 6-2 sum up the overall results.

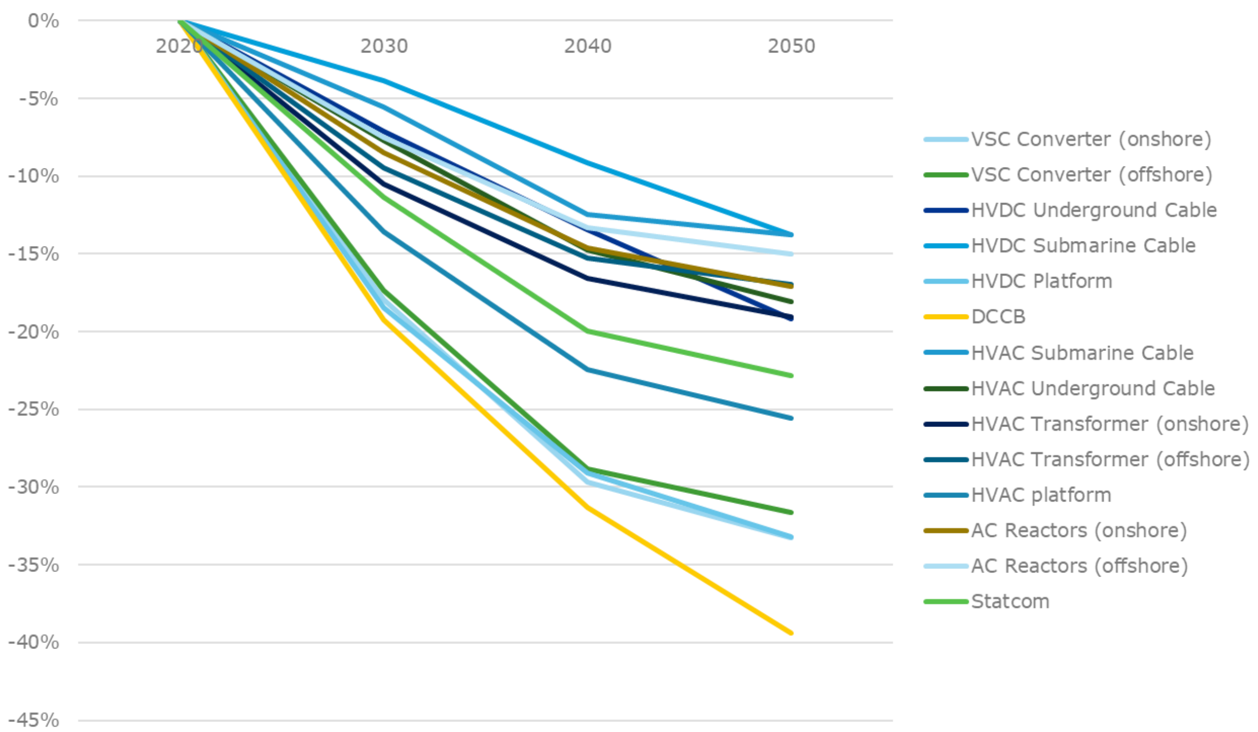


Figure 6-3 Estimated cost development of HVAC and HVDC components towards 2050

Table 6-1 Estimated cost development of DC components towards 2050

	VSC Converter (onshore)	VSC Converter (offshore)	HVDC Underground Cable	HVDC Submarine Cable	HVDC Platform	DCCB
2030	-18 %	-17 %	-7 %	-4 %	-18 %	-19 %
2040	-30 %	-29 %	-13 %	-9 %	-29 %	-31 %
2050	-33 %	-32 %	-19 %	-14 %	-33 %	-39 %

Table 6-2 Estimated cost development of AC components towards 2050

	HVAC Submarine Cable	HVAC Underground Cable	HVAC Transformer (onshore)	HVAC Transformer (offshore)	HVAC platform	AC Reactors (onshore)	AC Reactors (offshore)	STATCOM
2030	-6 %	-8 %	-10 %	-9 %	-14 %	-8 %	-7 %	-11 %
2040	-12 %	-15 %	-17 %	-15 %	-22 %	-15 %	-13 %	-20 %
2050	-14 %	-18 %	-19 %	-17 %	-26 %	-17 %	-15 %	-23 %

The components that are estimated to experience the steepest decrease in cost level are DCCB, VSC Converter (onshore), DC platform and VSC Converter (offshore). Components with less steep decrease are AC Sea Cable, DC Sea Cable, AC Reactors (offshore), AC Reactors (onshore) and AC Transformer (offshore).

We can observe that DCCB has the steepest cost decline among the components listed in Figure 6-3. DCCB is based on emerging technology, and hence the R&D cost is expected to decline rapidly as the technology becomes mature.

Among the components listed in Figure 6-3, STATCOM is rather similar to VSC converters in the underlining technology, however the cost decline for STATCOM is rather moderate as compared with VSC converters. This can be attribute to the higher technology maturity level of STATCOM, which implies lower potential for cost decline.

6.4. Cost for emerging technologies

The cost for emerging technologies was estimated using one of the two methods listed below:

- One is based on the cost model of the similar technology. This method has been applied in the products that are still under development, but alternative products exist and have similar functionalities and configurations. For example, FB VSCs and DRU. FB VSCs are still under development and with limited number of awarded contracts, but HB VSCs are well developed which have similar functionalities and configurations as FB VSC. In this case a cost model for FB VSC will be built using HB VSC as reference base and estimating the incremental cost between HB VSC and FB VSC.
- The other is a "bottom-up" approach, which has been applied to the products that are relatively new or unique. Since this type of products are not yet available in the market and there is very few or no commercial projects with such products, it is therefore not possible to establish the cost data through historical data. Furthermore, due to the unique feature of those products, it is also difficult to establish the cost model by evaluating the cost data of similar products. A "bottom-up" approach was used to obtain the direct material cost. The other cost items (labour, R&D, profit margin, etc) were estimated as additional percentages of the direct material cost. This applies mainly to DCCBs with different solutions.

At this stage, more speculative technologies, such as Low Frequency AC (LFAC), superconductive cables and DC collector grid, are not included in the cost database. If, in the later stage of the project, any such technologies are identified to be applicable within the time horizon of this project, we expect that their cost estimate can be established using one of the two methods mentioned above.

7. POWER SYSTEM ANALYSIS

This section provides a summary of the holistic design approach adopted for the power system analysis of the conceptual offshore network designs and describes the:

- study inputs updated to include possible future offshore wind capacity up to 2050;
- modelling assumptions;
- scope of simulations carried out to quantify how power transfer across transmission system boundaries differs between integrated design and counterfactual options;
- potential transmission system constraints and critical areas where reinforcements may be required that were identified, and
- limitations of the study (such as impact on dynamic performance and voltage control capabilities of the transmission system).

7.1. Approach

7.1.1. Inputs

The following inputs were used to carry out the power system analysis:

From ESO

- Computer simulation model of the GB transmission network. The model is a depiction of the year 2028, as forecasted in the ESO's ETYS 2019 report.
- Offshore wind capacity per flop zone, annual wind load factors and interconnector load factors between the years 2025-2050, in accordance to the LW scenario, as described in the ESO's FES 2020 report.
- Reinforcements of the onshore transmission network between the years 2020-2039, in accordance with the NOA 2020 report.

From the conceptual offshore network designs

- Points of connection to the onshore transmission network for each counterfactual and integrated offshore network design option.
- Active power injection of the counterfactual and integrated offshore network designs at each point of connection to the transmission system. This item is particularly relevant for interlinked HVDC connections, since it is possible to control how the power flow is distributed between the points of connection.

7.1.2. Modelling Assumptions

The following assumptions were considered for the modelling of the conceptual offshore network designs:

- The simulation model of the transmission system in GB for the year 2028 has been updated to include the offshore wind capacity forecasted between the years 2028-2050 (see Appendix G).
- The new offshore wind capacity has been modelled as a set of active power injections at the points of connection specified by the conceptual offshore network designs. The active power injections constitute the 70% of the installed wind capacity (see Figure 7-1 for example and Appendix I for all regions). This amount of power injection corresponds to the economy dispatch, as stated in the SQSS.
- In the integrated offshore network design, the power transferred via interlinked HVDC connections (i.e. topologies T5 and T7 from Table 4-1), has been distributed between the landing points as to produce the largest benefit on the onshore boundaries. In other words, the end of the connection with less capacity constraints was loaded to the maximum admissible power, limited by the rating of the converters, whilst the residual power was distributed to the less desirable boundary. Generally, this translates into loading the southern end of the connections more than the northern end.
- The net active power demand in the simulation model of GB's transmission system for 2028 is 46 GW, excluding losses. For the year 2030, it has been assumed to keep the same demand. For the year 2050, the demand present in the model has been equally scaled up to reach 60 GW (+30%). This growth is approximately the same as forecasted for the total demand in the LW scenario, as indicated in the FES 2020 report
- New reactive power compensation equipment between the years 2028-2050 has not been included in the model. Furthermore, the reactive power injection of the offshore wind capacity between the

years 2028-2050 has been set to zero. The quadrature boosters installed in the grid are not optimised for the future scenarios either.

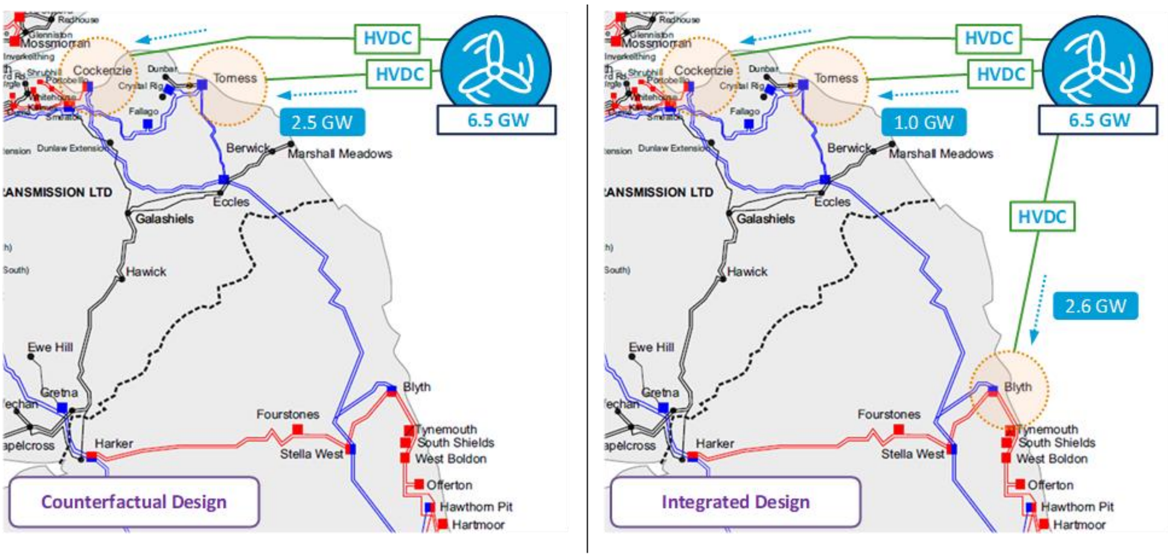


Figure 7-1 Installed capacity vs. active power injection. East Scotland (2025–2050).

7.1.3. Scope of Simulations

The model of the conceptual offshore network designs was only intended to demonstrate the impact of the active power injections from offshore wind on the power flow distribution across the onshore transmission system and therefore its use was limited to power flow studies. Due to the complexity of the model, convergence issues in the HVAC power flow calculation, caused by the excessive future overloads and inadequate voltage profiles (especially for the year 2050), are overcome with the HVDC power flow calculation (i.e. only the active power flows are considered).

The simulations provide information on boundary power transfers and allowed potential constraints in the network, such as overloads in transmission lines and inadequate voltage profiles, to be identified. The outcome of the simulations highlighted risky areas in the transmission system the extent or type of reinforcements that may be required. It is recommended that possible options to solve the constraints, should be analysed in more detail as part of subsequent studies. Furthermore, when a potential constraint was identified in the simulation, it was verified if such constraint had also been identified during the relevant time period in the NOA 2020 report.

7.1.4. Limitations

At this stage of the project, two main factors limit the outcome of the power system analysis which are the reduced number of operational scenarios analysed and the modelling approach used for the conceptual offshore network designs.

The performed power flow simulations gave a high-level indication on how the conceptual offshore network designs would impact on the power transfers across onshore boundaries of the transmission system allowing problematic areas where grid reinforcements might be required to be identified. Nonetheless, for each of the years considered, i.e. 2030 and 2050, only one generation and dispatch scenario has been analysed. In order to thoroughly identify all potential constraints, it would be necessary to perform the study with as many operational scenarios as possible.

With respect to the modelling of the conceptual offshore network designs, whilst representation of a set of active power injections was sufficient to analyse the impact on the power flows across the onshore network, it also imposed scope limitations for this study. The following complex technical items were not investigated in detail as part of this assessment:

- **Dynamic performance:** Each of the technologies considered for the development of the conceptual offshore designs provides different technical capabilities, as overviewed in Table 4-1. In order to analyse their dynamic behaviour, e.g. fault response, detailed modelling of the control systems and protection schemes would be required.

- **Voltage regulation:** The extent to which offshore wind contributes to voltage regulation onshore depends again on the technical capabilities of the different technologies, but also on the inclusion of reactive power compensation equipment. Moreover, areas of the transmission system with a high infeed of wind power might require additional reactive power compensation equipment onshore.
- **Losses on the offshore network:** Since the electrical equipment of the possible offshore network design solutions is not modelled explicitly (e.g. HVDC converters, cables, transformers), offshore power losses could not be quantified within the simulations.

The topics listed above are discussed on a qualitative basis only. It is recommended that detailed analysis is carried out as part of subsequent project stages.

7.2. Analysis per Regional Zone

This section presents the outcomes of the power flow simulations for each of the considered regional zones: North Scotland, East Scotland, Dogger Bank, Eastern Regions, South East and North Wales and Irish Sea. The power flow results quantify the onshore boundary capacity benefits brought by the integrated offshore network design. Boundary capacity is one of the main factors that can influence the operation of the transmission system in GB and associated planning needs for the future.

For each region (the covered flop zones), the boundaries of interest and the installed offshore wind capacity for the years 2030 and 2050 are indicated first. Then, the main differences between the connection of the offshore wind between the counterfactual and integrated designs are indicated (see Appendix I for detailed active power injections per point of connection). Last, the main findings are discussed, highlighting critical network constraints and potential needs for reinforcements. Detailed numerical results per regional zone for the boundary power transfers and transmission lines with loading levels above 70% are also included, since the risk of overloading during onshore contingencies is more elevated.

In presenting specific power flow scenarios within the GB system it had been necessary to make certain specific assumptions regarding connections of offshore wind within the onshore transmission system. It is not possible within a dataset of this scale and complexity within the timeframe of this work to identify detailed local onshore transmission solutions onshore, whether to existing or new substations, nor in detail how local network may be re-configured or extended to accommodate the project by project connections in the counterfactual approach (via the Connections Infrastructure Options Note process). Instead we have referenced in our discussion of power system injections, specific locations of power injections within the wider, non-local power boundaries discussed above. These are acting as a more general representation of the project by project injections as particular points within these power boundaries. Where, for example, you see we mention Sizewell in these counterfactual injections being studied, we are rather referring to a range of local solutions which may occur within the EC5 boundary discussed. Not simply or necessarily that one site, but a one for which an equivalent representation at that location may be used to illustrate power flow impact.

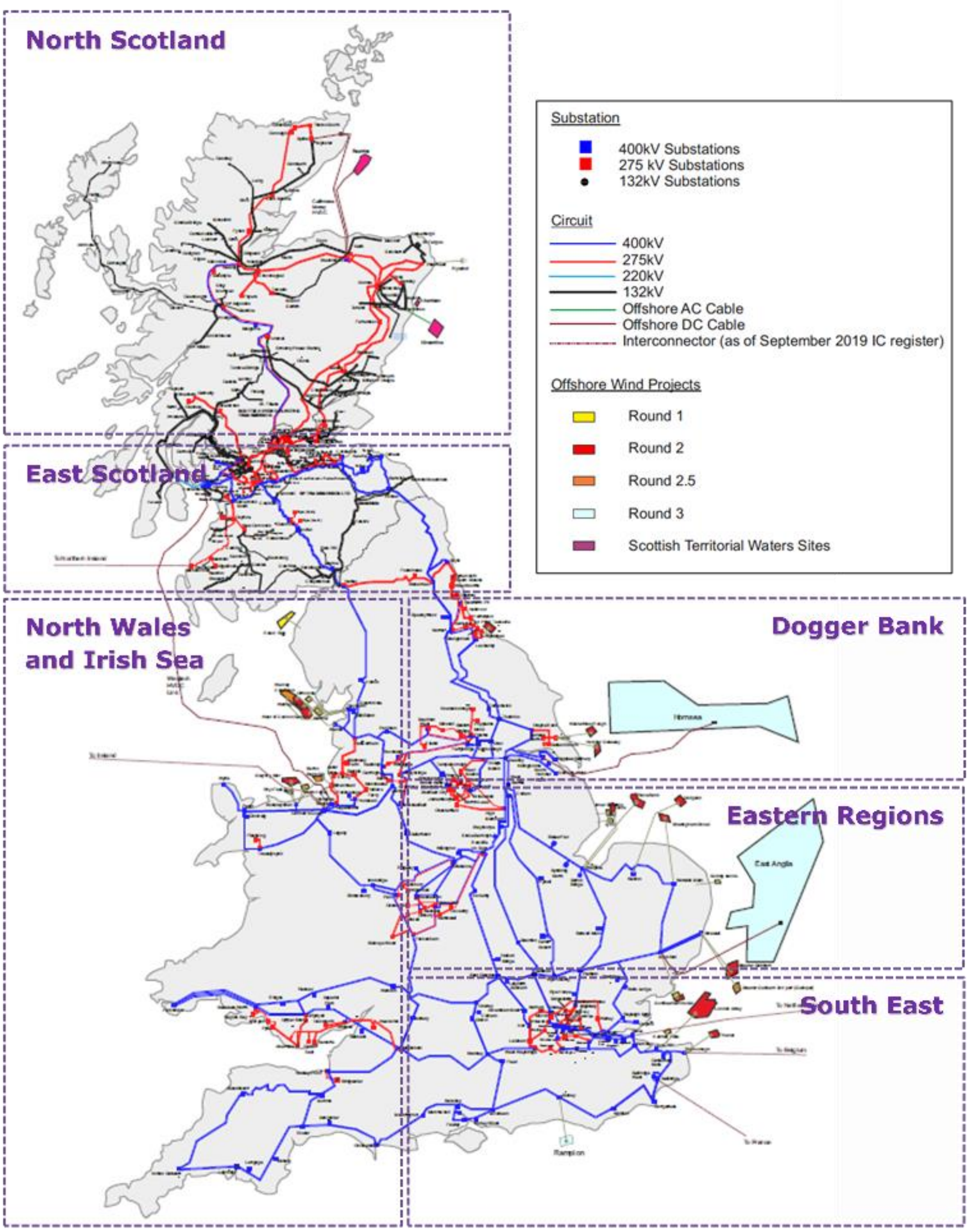


Figure 7-2 GB's existing transmission system and considered regional zones.

7.2.1. North Scotland

The analysis of North Scotland covers flop zones T1, T2, T5 and T6. The considered boundaries are B0 (1.03 GW), B1a (2.30 GW) and B2 (2.70 GW).

Installed Capacity

In North Scotland, offshore wind capacity is associated to flop zones T2, T5 and T6. The amount of offshore wind capacity forecasted for the future is the following:

- **Year 2025:** 2.46 GW.
- **Year 2030:** 6.46 GW (+4.00 GW).
- **Year 2050:** 17.96 GW (+11.50 GW).

Power Injections

The new power capacity between the years 2025-2030 is distributed in the counterfactual design between Spittal (P4) via HVAC, Beauly (T1) via HVDC and Peterhead (T2) via HVDC. The power injection at Spittal (P4) is transferred to Peterhead via a new HVDC interconnection, whilst another new HVDC interconnector to Drax (P4) exports wind power to England. In the integrated design, all the wind capacity is only connected to Peterhead (T2), and most of the power in this case is exported to England via the same HVDC interconnector to Drax (P4).

The new power capacity between the years 2030-2050 is distributed in the counterfactual design between Peterhead (T2) via HVDC from Shetland, Spittal (T5) and Keith (T6) via HVAC. In the integrated design, wind capacity is also connected to Peterhead (T2), Kintore (T2) and Keith (T6), all via HVDC. Almost half of the power is exported to England via a HVDC interconnector between Kintore (T2) and Cottam (K5).

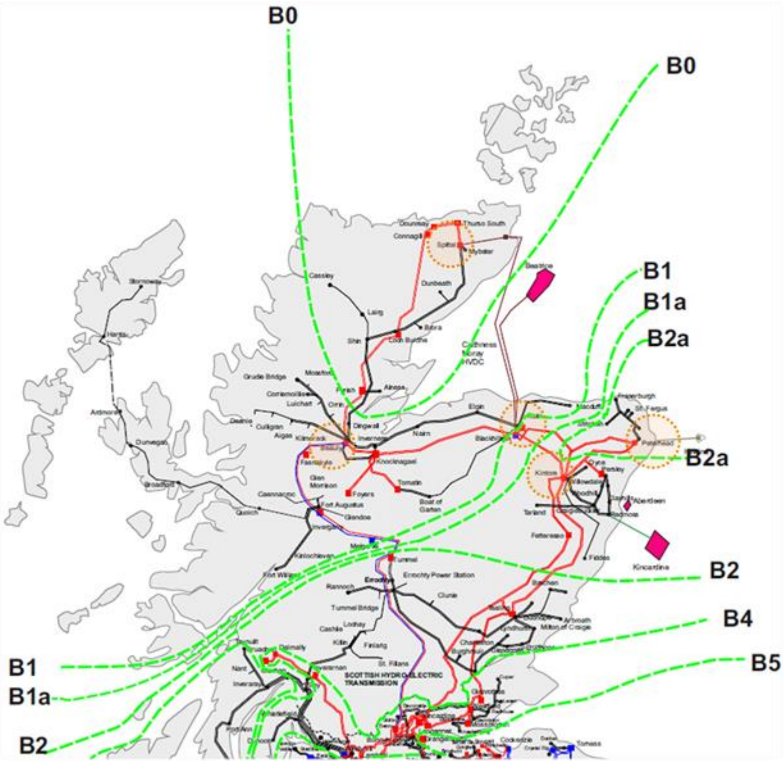


Figure 7-3 Existing transmission system in the region of North Scotland.

Boundary Power Transfers

With the integrated design, the combined power transfer across all the considered boundaries is reduced by 20% in 2030 and by 60% in 2050. This is achieved by connecting the offshore areas in North Scotland directly to England's network via the HVDC links to Drax (P4) and Cottam (K5). Conversely, transporting the offshore power via the onshore boundaries will trigger extensive system reinforcements in 2050.

Constraints and Reinforcements

According to the NOA 2020, it is expected that the transmission path between Peterhead–Kincardine, rated at 275 kV, will be upgraded to 400 kV prior to 2030. With this upgrade, the simulations results for the counterfactual and integrated designs do not trigger further reinforcements in this path before 2030.

The counterfactual design for 2030 explicitly includes the need for other reinforcements required for the integration of the new offshore wind, i.e. new HVDC link from Spittal (P4) to Peterhead (P2), new Western Isles reinforcement into Beauly (T1) and new HVDC link along the east coast. Once again, the simulations results do not indicate further reinforcement needs once these additional reinforcements have occurred to support the higher B0, B1a and B2 boundary flows seen in the counterfactual design. For 2050, and under N-0 conditions, the significant increase of installed offshore wind capacity leads to loading levels above 200% in the transmission path between Spittal–Bonnybridge and around 100% in the transmission path between Peterhead–Kincardine. Consequently, additional reinforcements such as continuing the uprate of the 275 kV grid to 400 kV and/or constructing new circuits are required to solve the overloads.

In the integrated design for 2050, the loading levels in the transmission path between Spittal–Bonnybridge are effectively mitigated. Between Kintore–Kincardine, the loadings are below 100% under N-0 conditions, yet overloads can occur under contingency situations.

Table 7-1 Simulation results for North Scotland.

	Year 2030			Year 2050		
	Counterfactual	Integrated		Counterfactual	Integrated	
Boundary Power Transfer [GW]						
B0	1.88	1.18	-37%	7.29	0.93	-87%
B1a	4.37	4.02	-8%	8.69	2.89	-67%
B2	5.23	4.23	-19%	11.44	7.14	-38%
Transmission Line Loading [%]						
Spittal–Dounreay	–	–	–	235	9	-226%
Shin–Dingwall	–	–	–	383	42	-341%
Fyrish–Beauly	–	–	–	375	31	-344%
Beauly–Fort Augustus	–	–	–	106	45	-61%
Melgarve–Bonnybridge	–	–	–	144	67	-77%
Tummel–Bonnybridge	78	65	-13%	95	47	-48%
Blackhillock–Kintore	–	–	–	103	5	-98%
Kintore–Tealing	–	–	–	111	94	-17%
Tealing–Kincardine	–	–	–	98	75	-23%
Fetteresso–Kincardine	–	–	–	105	80	-25%

7.2.2. East Scotland

The analysis of East Scotland covers flop zones T3, T4, S5 and S6. The considered boundary in this region is B6 (5.76 GW).

Installed Capacity

In East Scotland, offshore wind capacity is associated to flop zones T4 and S6. The amount of offshore wind capacity forecasted for the future is the following:

- **Year 2025:** 2.82 GW.
- **Year 2030:** 5.12 GW (+2.30 GW).
- **Year 2050:** 9.32 GW (+4.20 GW).

Power Injections

The new power capacity between the years 2025-2030 in the counterfactual design is connected via HVDC to Cockenzie (S6) and Torness (S6). In the integrated design, all the wind capacity is connected to Blyth (Q4) via HVDC.

The new power capacity between the years 2030-2050 in the counterfactual design is again connected via HVDC and split between Cockenzie (S6) and Torness (S6). In the integrated design, the power injections are distributed between Cockenzie (S6), Torness (S6) and Blyth (Q4), all via HVDC. Note that the HVDC connections to Blyth (Q4) and Torness (S6) are interlinked offshore.

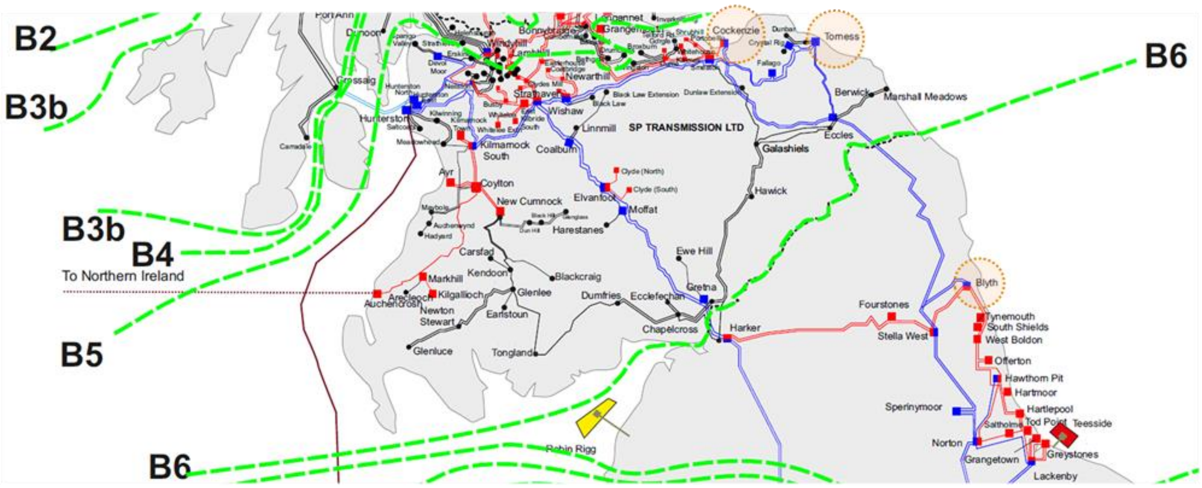


Figure 7-4 Existing transmission system in the region of East Scotland.

Boundary Power Transfers

In a similar fashion to the North Scotland case, the integrated design for the region of East Scotland leads to reduced power transfers across the Scottish-English border, up to 50% in 2050. In the counterfactual design, the B6 boundary flow will exceed its current rating of 5.76 GW already in 2030.

Constraints and Reinforcements

In the counterfactual design, the results for 2030 indicate loading levels close to 100% in the transmission path between Elvanfoot–Harker. For 2050, N-0 conditions lead to loading levels above 170% in said path. On top of that, the transmission path between Eccles-Stella West and several lines of the 275 kV grid in the south of Scotland become overloaded as well.

In the integrated design, all the loading levels are reduced, especially in the transmission path between Eccles-Stella West and the 275 kV grid in the south of Scotland. The main cause for this is the transfer of offshore power directly to Blyth (Q4) via HVDC interconnection. However, the transmission path between Elvanfoot–Harker is also overloaded in 2050.

According to the NOA 2020, reconductoring the Elvanfoot–Harker path was planned for 2026, but it has been stopped for the time being. The obtained simulation results hint that a reinforcement will be eventually needed by 2030, both for the counterfactual and integrated designs. For 2036, a reinforcement in the transmission path between Torness-Stella West is expected. This will indeed be required for the counterfactual design, but it may be potentially avoided in the integrated design.

Table 7-2 Simulation results for East Scotland.

	Year 2030			Year 2050		
	Counterfactual	Integrated		Counterfactual	Integrated	
Boundary Power Transfer [GW]						
B6	7.23	4.54	-37%	14.86	7.24	-51%
Transmission Line Loading [%]						
Bonnybridge–Denny	84	70	-14%	160	72	-88%
Denny–Lambhill	–	–	–	86	62	-24%
Clyde's Mill–Strathaven	–	–	–	130	80	-50%
Strathaven–Wishaw	–	–	–	100	54	-46%
Strathaven–Coalburn	–	–	–	131	56	-75%
Coalburn–Elvanfoot	–	–	–	157	83	-74%
Elvanfoot–Moffat	81	60	-21%	171	93	-78%
Elvanfoot–Gretna	87	66	-21%	177	99	-78%
Moffat–Harker	102	80	-22%	191	113	-78%
Gretna–Harker	94	74	-20%	181	105	-76%
Tealing–Westfield	–	–	–	125	99	-26%
Westfield–Longannet	–	–	–	96	73	-23%
Kincardine–Currie	–	–	–	119	84	-35%
Currie–Kaimes	–	–	–	86	53	-33%
Kaimes–Smeaton	–	–	–	95	51	-44%
Cockenzie–Eccles	–	–	–	143	56	-87%
Eccles–Stella West	–	–	–	120	44	-76%

7.2.3. Dogger Bank

The analysis of the Dogger Bank covers flop zones P1, P2, P8, Q2, Q4, Q5, Q6, Q7 and Q8. The considered boundaries are B7 (6.33 GW) and B8 (10.32 GW).

Installed Capacity

In the Dogger Bank region, offshore wind capacity is associated to flop zones P8 and Q2. The amount of offshore wind capacity forecasted for the future is the following:

- **Year 2025:** 4.53 GW.
- **Year 2030:** 7.63 GW (+3.10 GW).
- **Year 2050:** 10.83 GW (+3.20 GW).

Power Injections

More than half of the new power capacity between the years 2025-2030 in the counterfactual design is connected to Keadby (P8) via HVDC. The remainder is connected to Creyke Beck (P8) via HVDC and to Lackenby (Q2) via HVAC. In the integrated design, the wind capacity connected to Lackenby (Q2) is the same, whilst all the remainder power is transferred south to Walpole (J1) via HVDC.

All the new power capacity between the years 2030-2050 is connected to Lackenby (Q2) via HVDC in the counterfactual design. In the integrated design, half of the power goes to Killingholme (P7) and Lackenby (Q2) respectively, both via HVDC. Note that the HVDC connections to Walpole (J1) and Killingholme (P7) are interlinked offshore.

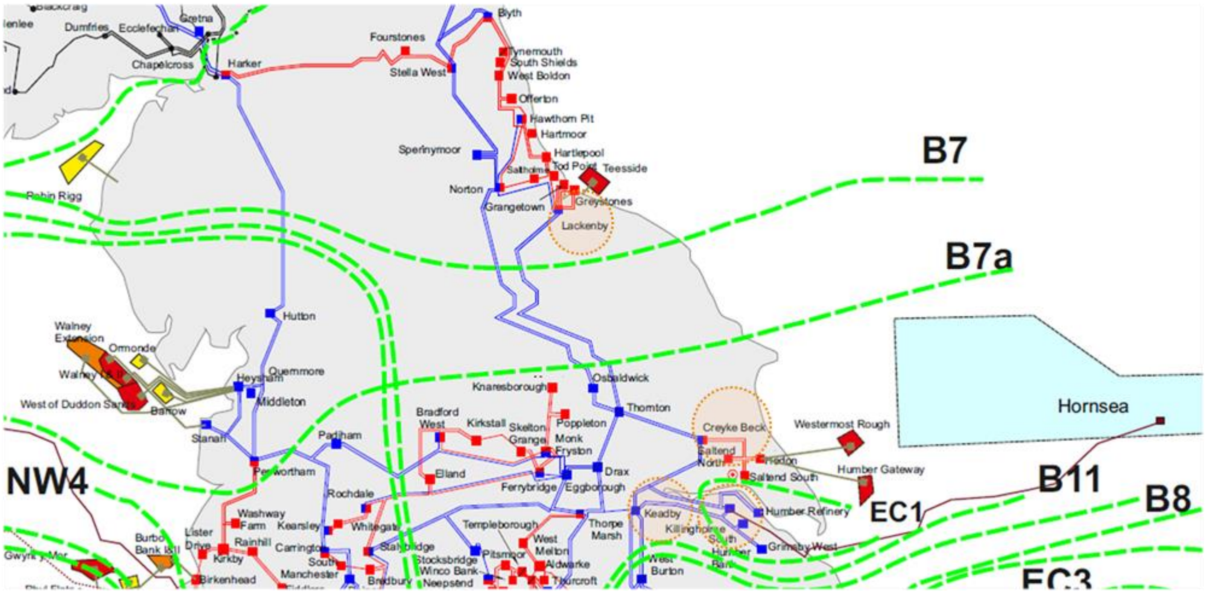


Figure 7-5 Existing transmission system in the region of Dogger Bank.

Boundary Power Transfers

With the integrated design, the power transfer across all the considered boundaries is reduced roughly by 15% in 2030 and by 35% in 2050. This is achieved by directly transporting a significant part of the power to the southern end of the boundaries via the offshore infrastructure, to Walpole (J1) in 2030 and to Killingholme (P7) in 2050.

Constraints and Reinforcements

In both the counterfactual and integrated designs, the simulation results for 2030 under N-0 conditions indicate loading levels close to or above 100% in the transmission path between Drax–Keadby-Cottam. This is also observed for the base 2028 case, and therefore it is independent of the offshore topologies. For 2050, the overloads increase further in the counterfactual design, especially in the Harker-Hutton and Norton-Osbaldwick lines. In the integrated design, all the loading levels are lower under N-0 conditions but might nonetheless cause issues under contingencies.

In the NOA 2020, reconductoring of the Norton-Osbaldwick transmission line is proposed before 2030, whilst a new 400 kV circuit between South Humber-South Lincolnshire is to be constructed after 2030. These reinforcements are in line with the obtained results. Furthermore, reinforcing the Harker-Hutton line should also be investigated.

Table 7-3 Simulation results for the Dogger Bank.

	Year 2030			Year 2050		
	Counterfactual	Integrated		Counterfactual	Integrated	
Boundary Power Transfer [GW]						
B7	9.55	8.38	-12%	18.86	12.73	-33%
B8 (Keadby path only)	10.58	8.64	-18%	14.99	8.71	-42%
Transmission Line Loading [%]						
Harker–Hutton	73	60	-13%	146	89	-57%
Stella West–Spennymoor	–	–	–	99	68	-31%
Spennymoor–Norton	–	–	–	93	62	-31%
Norton–Osbaldwick	91	70	-21%	168	114	-54%
Lackenby–Thornton	–	–	–	105	79	-26%
Drax–Keadby	96	107	+11%	127	101	-26%
Keadby–West Burton	107	103	-4%	143	96	-47%
Keadby–Cottam	111	86	-25%	138	68	-70%
West Burton–Cottam	88	91	+3%	125	78	-47%

7.2.4. Eastern Regions

The analysis of the Eastern Regions covers flop zones J1, J2, J3, J4, J5, J6, J7, K1, K2, K4, K5, K6, P4, P6 and P7. The considered boundaries are B9 (12.50 GW) and EC5 (3.55 GW).

Installed Capacity

In the Eastern Regions, offshore wind capacity is associated to flop zones J1, J2, J3, J5, K4 and P7. The amount of offshore wind capacity forecasted for the future is the following:

- **Year 2025:** 10.10 GW.
- **Year 2030:** 17.45 GW (+7.35 GW).
- **Year 2050:** 27.52 GW (+10.07 GW).

Power Injections

More than half of the new power capacity between the years 2025-2030 in the counterfactual design is connected via HVDC to Norwich Main (J3). The remainder power is distributed between Walpole (J1), Sizewell (J2) and Necton (J3) via HVAC and Bramford (J2) via HVDC. In the integrated design, the power injections to Bramford (J2) and Sizewell (J2) are the same, but for Sizewell it is realised via the Nautilus HVDC interconnector. The remainder power is distributed between Grain (C3) and Walpole (J1) via HVDC connections interlinked offshore.

The new power capacity between the years 2030-2050 in the counterfactual design is connected to Walpole (J1) and Sizewell (J2) via HVAC and to Norwich Main (J3) and Killingholme (P7) via HVDC. In the integrated design, more than half of the total power is distributed between Kemsley (C3) and Tilbury (C1) via HVDC connections interlinked offshore. The remainder power injection is brought to shore via the following HVDC interconnectors: NeuConnect and Southern Link to Grain (C3), Nemo Link to Richborough (C7) and Eleclink to Sellindge (C4).

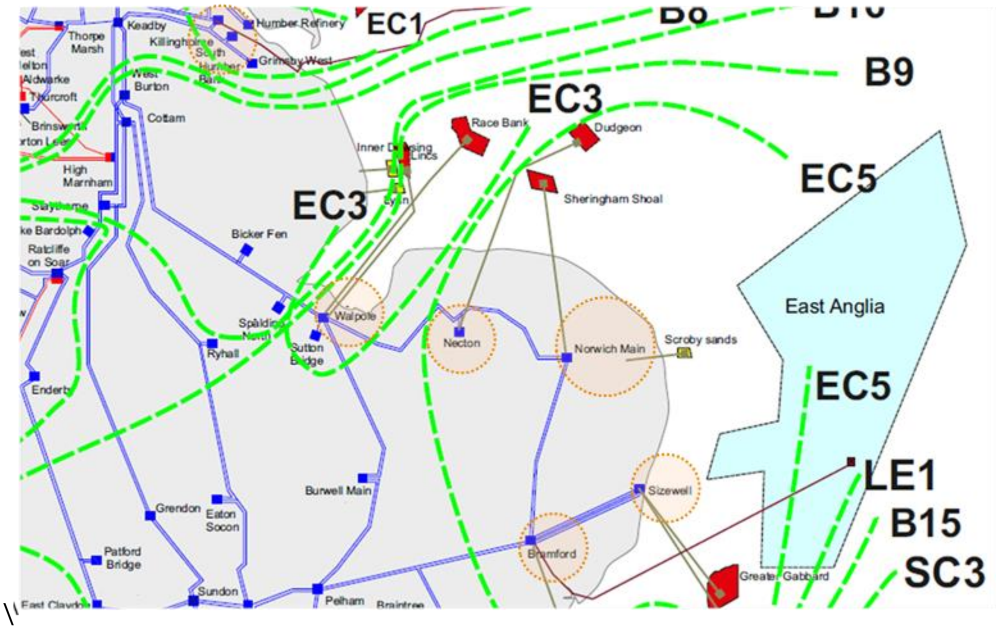


Figure 7-6 Existing transmission system in the region of Eastern Regions.

Boundary Power Transfers

With the integrated design, the combined power transfer across all the considered boundaries is reduced by 20% in 2030 and roughly by 50% in 2050. Once again, the reduction is achieved by directly transporting a significant part of the power to the southern end of the boundaries via the offshore infrastructure, in this case mainly to the Grain (C3) area.

Constraints and Reinforcements

In both the counterfactual and integrated designs, the simulation results for 2030 under N-0 conditions indicate loading levels close to 100% in the transmission path between West Burton–Ratcliffe on Soar, which are more severe for 2050. Quad boosters are installed along this path, which can further influence the power flow distribution. Also, the loading levels between Cottam-Sundon and Walpole-Pelham are above 100% in the counterfactual design.

The NOA 2020 has not identified constraints in any of the highlighted areas for the time being. Further investigation may be required. Reconductoring the Norwich Main-Bramford line for 2024 has been hold, which also has not been identified as a constraint in the simulations for 2030.

Table 7-4 Simulation results for the Eastern Regions.

	Year 2030			Year 2050		
	Counterfactual	Integrated		Counterfactual	Integrated	
Boundary Power Transfer [GW]						
B9	14.92	11.77	-21%	20.38	12.16	-40%
EC5	4.36	3.22	-26%	6.93	2.29	-67%
Transmission Line Loading [%]						
West Burton–High Marnham	82	80	-2%	113	102	-11%
High Marnham–Stoke Bardolph	104	98	-6%	143	118	-25%
Stoke Bardolph–Ratcliffe on Soar	97	90	-7%	134	109	-25%
Enderby–East Claydon	–	–	–	94	44	-50%
Cottam–Staythorpe	65	75	+10%	100	127	+27%
Staythorpe– Ratcliffe on Soar	71	68	-3%	92	109	+17%
Cottam–Grendon	83	65	-18%	113	94	-19%
Grendon–Sundon	79	64	-15%	107	77	-30%
Walpole–Burwell Main	73	76	+3%	105	72	-33%
Burwell Main–Pelham	70	73	+3%	101	68	-33%
Norwich Main–Bramford	–	–	–	84	15	-69%

7.2.5. South East

The analysis of the South East covers flop zones A1, A3, A4, A6, A7, A8, A9, B1, C1, C2, C3, C4, C5, C6 and C7. The considered boundaries are SC1 (4.14 GW) and SC3 (6.26 GW).

Installed Capacity

In the South East, offshore wind capacity is associated to flop zones B1, C3 and C7. The amount of offshore wind capacity forecasted for the future is the following:

- **Year 2025:** 1.33 GW.
- **Year 2030:** 1.67 GW (+0.34 GW).
- **Year 2050:** 2.07 GW (+0.40 GW).

Power Injections

The new power capacity between the years 2025-2030 in the counterfactual design is connected to Richborough (C7) via HVAC. In the integrated design, it is also connected to Richborough (C7) but via the Nemo HVDC Link.

The new power capacity between the years 2030-2050 in the counterfactual design is connected to Bolney (B1) via HVAC. In the integrated design, it is again connected to Richborough (C7) via the Nemo Link.

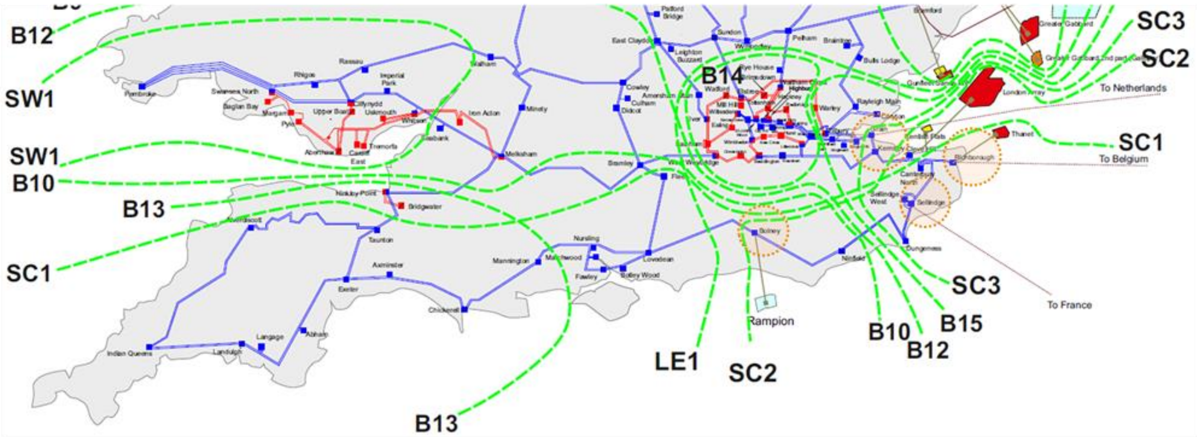


Figure 7-7 Existing transmission system in the region of South East.

Boundary Power Transfers

As indicated for the Eastern Regions, the transportation of offshore power from that region directly to the Grain (C3) area leads to a lower power transfer across the relevant boundaries in the integrated design. For 2050, this translates into more than double power transfer across boundary SC3. Nonetheless, the integrated design still triggers less additional reinforcements in the region than the counterfactual design.

Constraints and Reinforcements

In the counterfactual design for 2030, and under N-0 conditions, the transmission path between Sundon–St John's Woods is loaded above 100%, whilst the area around Bramford and Tilbury is loaded close to 100%. The loadings in the integrated design are lower, yet close to 100% in some of the lines. For 2050, the loading levels are above 100% for almost all of the lines in the counterfactual design. Conversely, the integrated designs provides significantly lower loading levels.

Several reinforcements are planned in the area before 2030 according to the NOA 2020, including reconductoring the Sundon–Elstree and Bramford-Tilbury transmission lines. These reinforcements are also deemed as necessary from the 2030 simulations. Moreover, and only applicable to the counterfactual design, a new HVDC interconnector between Sizewell-Canterbury is also foreseen shortly after 2030, which would benefit the power flow distribution across the region.

Table 7-5 Simulation results for the South East.

	Year 2030			Year 2050		
	Counterfactual	Integrated		Counterfactual	Integrated	
Boundary Power Transfer [GW]						
SC1	7.77	7.82	+1%	9.05	8.48	-6%
SC3	2.61	2.46	-6%	3.72	7.76	+109%
Transmission Line Loading [%]						
Sundon–East Claydon	–	–	–	103	93	-10%
Sundon–Cowley	–	–	–	104	80	-24%
East Claydon–Cowley	79	60	-19%	127	86	-41%
Cowley–Didcot	–	–	–	93	66	-27%
Didcot–Bramley	79	71	-8%	112	80	-32%
Iver–West Weybridge	75	61	-14%	105	54	-51%
Sundon–Elstree	117	97	-20%	151	77	-74%
Elstree–St John's Wood	110	89	-21%	141	63	-78%
Bramford–Bulls Lodge	113	90	-23%	155	73	-82%

Bramford–Rayleigh Main	85	75	-10%	118	54	-64%
Rayleigh Main–Coryton South	99	81	-18%	100	41	-59%
Rayleigh Main–Tilbury	96	76	-20%	129	44	-85%
Coryton South–Tilbury	95	65	-30%	127	29	-98%
Tilbury–Kingsnorth	80	55	-25%	102	33	-69%
Kingsnorth-Grain	–	–	–	19	73	+54%

7.2.6. North Wales and Irish Sea

The analysis of the North Wales and Irish Sea region covers flop zones H1, H2, H6, G1, G5, G6, G7, L1, L2, L5, M4, M5, M6, M7, M8, N1, N2, N3, N4, N5, N6, N7, N8, R4, R5 and R6. The considered boundaries are B7a (8.73 GW), NW1 (1.80 GW), NW3 (5.51 GW) and SW1 (3.90 GW).

Installed Capacity

In the North Wales and Irish Sea region, offshore wind capacity is associated to flop zones M6, M8, N3, Q8, R4 and R5. The amount of offshore wind capacity forecasted for the future is the following:

- **Year 2025:** 2.65 GW.
- **Year 2030:** 3.65 GW (+1.00 GW).
- **Year 2050:** 15.45 GW (+11.80 GW).

Power Injections

The new power capacity between the years 2025-2030 in the counterfactual design is connected to Pentir (M6) via HVAC and in the integrated design to Pembroke (H6) via HVDC.

The new power capacity between the years 2030-2050 in the counterfactual design is distributed between Pentir (M6) via HVDC, Wylfa (M8) via HVAC and Birkenhead (N3) via HVAC. In the integrated design, interlinked HVDC connections are used between Penwortham (R4) – Wylfa (M8) – Pembroke (H6) and between Heysham (R5) – Cilfynydd (H6). The power injections at Pembroke (H6), Cilfynydd (H6) and Wylfa (M8) are the maximum allowed by the HVDC converter ratings, while Penwortham (R4) and Heysham (R5) equally split the remainder power injection.

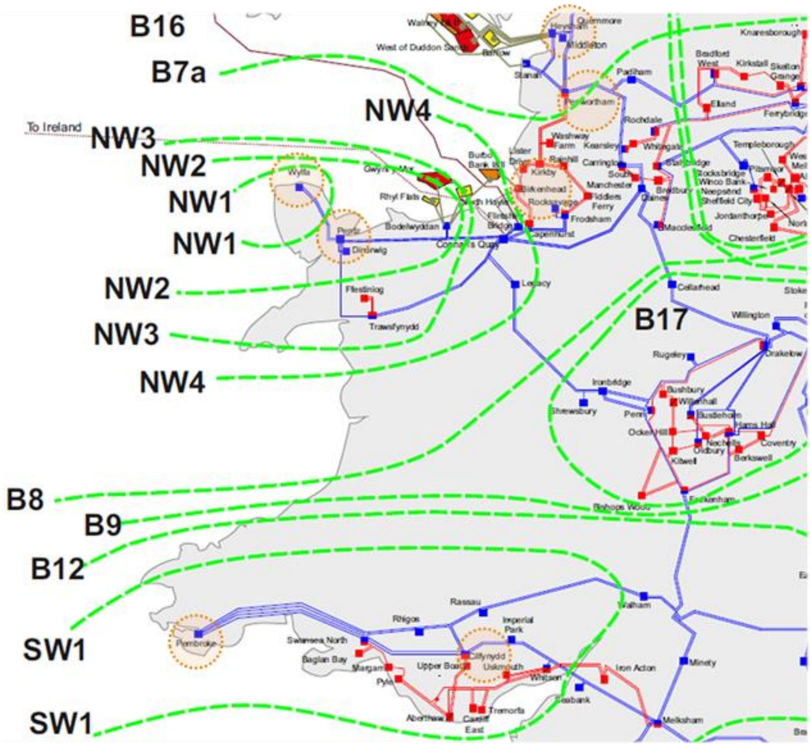


Figure 7-8 Existing transmission system in the region of North Wales and Irish Sea.

Boundary Power Transfers

With the integrated design, a significantly lower power transfer is achieved across boundary NW3 for 2030, yet the power transfer across boundary SW1 only increases slightly. This is caused by a power flow reversal between Pembroke-Walham, since the offshore wind power is now injected at Pembroke. Thereby, the power transfer that reaches Walham from North Wales is reduced, which in turn overcomes most of the power flow increase in the southern part of boundary SW1.

In 2050, the integrated design results in a net combined power transfer reduction above 40% across the northern boundaries. The behaviour of the southern boundary is comparable to 2030, as the power flow distribution changes, but the total amount of power transfer is similar.

Constraints and Reinforcements

In the counterfactual design, the results for 2030 indicate loading levels close to 100% in the transmission path between Legacy–Minety (the quad boosters at Legacy substation can further influence the power flow distribution). The overloads worsen in 2050 due to the highest power transfer from North to South Wales, and further constraints are identified in the Daines–Feckenham path and Connah's Quay area. With loading levels above 100%, reinforcements are required for the integration of the offshore wind. Note that the NOA 2020 does not include the analysis of the Welsh region.

In the integrated design, the most severe constraints occur in 2050 in the Penwortham–Kearsley and Whitson–Seabank lines, where the loading is above 100% under N-0. Other lines in the Penwortham and Drakelow areas are loaded between 80%-95%, which could lead to overloads during contingencies. Note that Heysham substation features a reference generator in the model. Since it is expected that conventional generation in Heysham will be decommissioned for 2050, the overloads reported in this area might be actually lower or not occur altogether.

Table 7-6 Simulation results for North Wales and Irish Sea.

	Year 2030			Year 2050		
	Counterfactual	Integrated		Counterfactual	Integrated	
Boundary Power Transfer [GW]						
B7a (Penwortham area only)	–	–	–	3.72	5.00	+34%
NW1	–	–	–	3.67	1.29	-65%
NW3	1.67	1.00	-40%	4.43	0.46	-90%
SW1	1.72	1.76	+2%	2.92	2.93	–
Transmission Line Loading [%]						
Penwortham–Carrington	87	73	-14%	87	105	+18%
Birkenhead–Lister Drive	–	–	–	134	62	-72%
Pentir–Trawsfynydd	–	–	–	159	13	-146%
Bodelwyddan–Connah's Quay	–	–	–	86	8	-78%
Connah's Quay–Legacy	–	–	–	104	69	-35%
Legacy–Ironbridge	85	72	-13%	142	64	-78%
Ironbridge–Feckenham	98	77	-21%	163	72	-91%
Daines–Drakelow	95	82	-13%	135	86	-49%
Drakelow–Feckenham	79	67	-12%	118	78	-40%
Feckenham–Minety	97	75	-22%	161	79	-82%
Whitson–Seabank	–	–	–	43	100	+57%

7.3. Analysis on System Level

This section presents the outcome of the power system analysis on the system level and gives a qualitative description of further technical items relevant for the evaluation of the security of supply, such as the impact of contingencies on the offshore network, the dynamic performance of different technologies and their potential contribution to voltage profiles.

7.3.1. Annual Wind Energy Production

According to the LW scenario, the total installed offshore wind capacity in GB will be approximately 42 GW in 2030 and 83 GW in 2050. The wind load factor forecasted for this scenario is 43% for both years 2030 and 2050. Therefore, it is estimated that the annual offshore wind energy production will be 158 TWh in 2030 and 313 TWh in 2050 (see Appendix H for breakdown per regional zone).

The electrical losses of the offshore network and the reliability of the equipment have an influence on how much energy can be actually brought to shore for each design. All the electrical equipment (e.g. HVDC converters, cables, transformers) must be modelled in detail in order to calculate the losses. In general, for long distances, HVDC solutions for offshore wind farms lead to a reduction of electrical losses of 1%-2% with respect to HVAC solutions[60].

7.3.2. Onshore Network Losses

The distribution of the power flows across an electricity transmission network has an impact on the total amount of power losses. In contrast to the counterfactual offshore design, which concentrates large infeed of wind power to the same landing areas, the integrated design allows to spread the active power injections across the network in a more balanced manner. Therefore, it is expected that the integrated design will lead to reduced power losses on the GB onshore transmission system.

60 https://www.sciencedirect.com/science/article/abs/pii/S0378779605002609

For illustration, the simulation of the studied operational scenario in the year 2030 leads to power losses of 3.23 GW in the counterfactual design and of 2.79 GW (-14%) in the integrated design. For the year 2050, the quantitative analysis becomes more complex without defining precise network reinforcements to solve inadmissible overloads in the transmission lines. Nonetheless, for the studied operational scenario, it is estimated that the integrated design could lead a power losses reduction up to 20%-30% in 2050.

7.3.3. Network Contingencies

According to SQSS requirements, the maximum permissible loss of generation in the event of a contingency offshore is 1320 MW. In the integrated design, the rating of the HVDC equipment and connections have been selected as to avoid surpassing the 1320 MW limit for a single component failure (e.g. export cable, converter station). Anyhow, it is expected that the same single component failure in an HVAC system will be less severe. For instance, a cable failure will lead to a maximum loss of 400 MW (assumed maximum rating for HVAC cables).

For interlinked HVDC connections, the offshore interties will be operated open or closed depending upon how large the wind output is. If the power generation is larger than 1320 MW and the power flow does not induce boundary constraints onshore, one or more interties (if available) will be closed to limit the largest loss of infeed power. When DC substations are present (i.e. North Scotland), these have been designed such that the DCCBs may be closed, and yet the loss of power does not exceed 1320 MW.

Interlinked HVDC connections also allow to rapidly redirect the power flows across the connections (up to 10 MW per millisecond), thereby limiting the impact of onshore contingencies when the initial power flow distribution presents an issue. Moreover, the converters used for HVDC bipole designs are specified to allow an additional 5% of power transfer above the rated capacity during post-fault situations. This extra capacity can be utilized even if the converter is fully loaded pre-fault. For illustration, should a fault occur in North Wales and require an additional 5% power flow to otherwise fully loaded South Wales connection, this may be achieved. Conversely, if a fault in South Wales requires power to be reversed into North Wales, this could also be achieved.

Simulation results indicate that several onshore transmission system paths will become overloaded in future scenarios under normal operational conditions (N-0). During single circuit contingencies (N-1), the loading level of the lines will increase further (e.g. up to twice the base loading level for double circuit lines), and therefore lines with loading levels below 100% under N-0 conditions could potentially become overloaded. Several operational scenarios should be investigated to estimate the probability of such events.

7.3.4. Dynamic Performance

Based on the trends observed in the ESO's System Operability Framework document, the fault level and inertia upon the onshore transmission in GB is expected to decline, as increasing levels of offshore wind capacity and interconnector flows develop in future years, together with the growth of other power electronic based technologies such as solar and batteries. Offshore wind capacity and the associated assets relating to its connection have the potential to offer solutions to the system impacts relating to lower inertia and fault levels. For example, these capabilities are discussed within the ESO's stability voltage and constraint pathfinders.

The proposed integrated design strategically locates the points of connections onshore, not only with the goal of achieving a tailored power flow across the onshore network, but also to allow equally strategically distributed stability support across the system. A holistic approach to the control priorities of the integrated offshore design across the landing locations offers the opportunity to enhance the onshore system rather than degrade it. The control of the HVDC systems may be designed to provide inertial, voltage and power flow support priority, reflecting the needs of the onshore systems.

The integrated offshore solutions, particularly those involving interlinked HVDC connections, offer wider stability functionalities to the system:

- Interlinked HVDC solutions contain fast acting flexible VSC-HVDC control systems operating in parallel to the transmission system, capable to provide oscillation damping and inertial power.
- Fast acting dynamic voltage support may be coordinated across the integrated system, optimising both active and reactive power deployment across the network.
- Using forms of grid forming control, sudden changes in voltage angle across the system could be limited, replicating the advantages of high fault level interconnected AC grids and further limiting the differences in regional frequency and rate of change of frequency.

For the counterfactual offshore design, only local support solutions could be replicated.

7.3.5. Voltage Profiles

Unlike the counterfactual design, the integrated solutions can distribute power differently onto the onshore system depending on its requirements at the time. In peak flow conditions, as illustrated by the performed simulations, the integrated solutions can limit the scale of power transfer across the onshore power system distance, that would otherwise lead to a lower voltage profile and risks of voltage stability post-fault.

At times of low onshore system power flows (e.g. summer day with high solar generation output and low demand, leading to a low North to South power transfer), the integrated solutions can redistribute the power to drive higher power flows across the onshore network, suppressing the effect from the no-load gain of that network, which would otherwise lead to voltage increase. This phenomenon can emerge quickly, and therefore the value of distributed and coordinated fast responding VSC-HVDC converters to rapidly respond to support these changes in hour to hour operation is important.

The locations of voltage control within the counterfactual design are mainly coastal and have no strategic distribution. As such, being distant to the areas where voltage challenges arise on the onshore system, these solutions are naturally less effective in responding to it than the integrated solution. The voltage control in the counterfactual does not have additional functionalities beyond grid code capability dependent on active power loading, nor would it be as fast and capable of coordination in the same way as the integrated control approach could achieve.

7.4. Conclusions

The presented power system analysis has investigated and compared the impact of the conceptual offshore network designs on the performance of onshore transmission system in GB. Onshore boundary power transfers, network constraints and transmission losses have been reported in a quantitative basis, whilst the impact of contingencies offshore, dynamic performance and voltage control have been discussed qualitatively.

The ESO’s grid simulation model for 2028 has been updated to include all future offshore wind capacity up to the year 2050, as forecasted for the LW scenario from the FES 2020. Using this dataset, simulations have been performed for 2030 and 2050 peak demand conditions of the Great Britain’s system, as to identify potential network constraints and needs for reinforcements in both the counterfactual and integrated designs.

The key findings of the power system analysis of the conceptual offshore network designs are:

- The growth of installed offshore wind capacity and demand forecasted between 2025-2050 will lead to increased power transfer across onshore boundaries. In general, the simulated boundary flows are lower in the integrated design, due to significant amount of wind power being transported via the offshore infrastructure.
- In the counterfactual design, a wide range of thermal overloads are present under N-0 conditions, which are in most part addressed by the integrated approach. The larger number of network constraints in the counterfactual design will trigger extensive reinforcements to the onshore grid to allow normal operational conditions, thereby incurring in higher investment costs than in the integrated design.
- The transmission losses in the onshore network are lower with the integrated design, since the wind power injections are spread across the network as to achieve reduced power transfer across the onshore boundaries.
- The impact of contingencies in the offshore transmission network is lower in the counterfactual design than in the integrated design, due to the increased number of connections to shore and the lower number of shared assets. Nonetheless, the maximum loss of offshore power in the integrated design is always limited to 1320 MW, compliant with existing SQSS requirements.
- The impact of contingencies in the onshore transmission network is significantly lower in the integrated design than in the counterfactual design, mainly due to the capability of interlinked HVDC connections to quickly redistribute the power transfer across the connections to aid the onshore system.
- The integrated design offers improved dynamic performance and voltage control in comparison to the counterfactual. The holistic approach of the integrated design (technologies, equipment ratings landing points) allows a coordinated control of the offshore assets, which translates into improved operational conditions in the onshore system.

8. APPENDICES

Appendix A Existing HVAC offshore wind connections in UK

Sno	Customer Name	Project Name	Capacity from Connection Date	Connection Date	Connection Site	Project Status
1	BURBO EXTENSION LTD	Burbo Bank Extension Offshore Wind Farm	258	06/04/2020	BURBO BANK EXTENSION OFFSHORE	Built
2	EAST ANGLIA ONE LIMITED	East Anglia One	680	30/11/2019	Platform EA One 220/66kV Offshore	Built
3	ABERDEEN OFFSHORE WIND FARM LIMITED	Aberdeen Offshore Wind Farm	96	Built	Blackdog 132kV Substation	Built
4	Awel Y Mor Offshore Wind Farm Ltd	Gwynt Y Mor Offshore Wind Farm	574	Built	Gwynt y Mor 132/33kV Offshore Substation	Built
5	Barrow Offshore Wind Ltd	Barrow Offshore Wind Farm	90	Built	Barrow 132/33kV Offshore Substation	Built
6	Beatrice Offshore Windfarm Ltd	Beatrice Wind Farm	588	Built	Beatrice 33/132kV Offshore Substations	Built
7	Dudgeon Offshore Wind Ltd	Dudgeon Offshore Wind Farm	400	Built	Necton 400kV	Built
8	GALLOPER WIND FARM LIMITED	Galloper Wind Farm	348	Built	Galloper North 132/33kV	Built
9	Greater Gabbard Offshore Winds Ltd	Greater Gabbard Offshore Wind Farm	500	Built	Gabbard 33/132kV Offshore Substation	Built

Sno	Customer Name	Project Name	Capacity from Connection Date	Connection Date	Connection Site	Project Status
10	Gunfleet Sands II Ltd	Gunfleet Sands II Offshore Wind Farm	64	Built	Gunfleet Sands 33/132kV Offshore	Built
11	Gunfleet Sands Ltd	Gunfleet Sands Offshore Wind Farm	100	Built	Gunfleet Sands 33/132kV Offshore	Built
12	HORNSEA 1 LIMITED	Hornsea Power Station 1A	400	Built	Hornsea Platform 1A Offshore	Built
13	HORNSEA 1 LIMITED	Hornsea Power Station 1B	400	Built	Hornsea Platform 1B Offshore	Built
14	HORNSEA 1 LIMITED	Hornsea Power Station 1C	400	Built	Hornsea Platform 1C Offshore	Built
15	Kincardine Offshore Windfarm Limited	Kincardine Offshore Wind Farm	2	Built	Redmoss 132/33kV Grid Supply Point Substation	Built
16	Lincs Wind Farm Ltd	Lincs Offshore Wind Farm	256	Built	Lincs 33/132kV Offshore Substation	Built
17	London Array Ltd	London Array Offshore Wind Farm	630	Built	London Array 33/150kV Offshore Substations	Built
18	Morecambe Wind Ltd	West of Duddon Sands Offshore Wind Farm	382	Built	West of Duddon Sands 34/155kV Offshore	Built
19	Ormonde Energy Ltd	Ormonde Offshore Wind Farm	150	Built	Ormonde 33/132kV Offshore Substation	Built

Sn o	Customer Name	Project Name	Capacity from Connection Date	Connection Date	Connection Site	Project Status
20	RACE BANK WIND FARM LIMITED	Race Bank Wind Farm	565	Built	Race Bank 132kV	Built
21	RAMPION OFFSHORE WIND LIMITED	Rampion Offshore Wind Farm	400	Built	Rampion 33/132kV Offshore	Built
22	RWE Renewables UK Humber Wind Ltd	Humber Gateway Offshore Wind Farm	220	Built	Humber Gateway 33/132kV Offshore Substation	Built
23	RWE Renewables UK Robin Rigg East Ltd	Robin Rigg East Offshore Wind Farm	86	Built	Robin Rigg East 132/33kV Offshore Substation	Built
24	RWE Renewables UK Robin Rigg West Ltd	Robin Rigg West Offshore Wind Farm	92	Built	Robin Rigg West Offshore Wind Farm	Built
25	Scira Offshore Energy Ltd	Sheringham Shoal Offshore Wind Farm	315	Built	Sheringham Shoal 33/132kV Offshore Substations	Built
26	Thanet Offshore Wind Ltd	Thanet Offshore Wind Farm	300	Built	Thanet 33/132kV Offshore Substation	Built
27	WALNEY (UK) OFFSHORE WINDFARMS LIMITED	Walney I Offshore Wind Farm	182	Built	Walney 1 33/132kV Offshore	Built
28	Walney (UK) Offshore Windfarms Ltd	Walney II Offshore Wind Farm	182	Built	Walney 2 33/132kV	Built
29	WALNEY EXTENSION LIMITED	Walney 3 Offshore Wind Farm	330	Built	Walney 3 Offshore	Built

Sn o	Customer Name	Project Name	Capacity from Connectio n Date	Connectio n Date	Connectio n Site	Projec t Status
30	WALNEY EXTENSION LIMITED	Walney 4 Offshore Wind Farm	330	Built	Walney 4 Offshore	Built
31	Westermost Rough Ltd	Westermost Rough Offshore Wind Farm	207	Built	Hedon 275kV	Built

Source: https://www.nationalgrideso.com/document/171261/download

Appendix B Operational HVDC VSC Projects

S.No	Name	Year Com-missioned	Power (MW)	Voltage DC (kV)	Voltage AC (kV)	Transmission Length (km)	Converter Manufacturer	Reference
1	Hällsjön - Sweden	1997	3	±10	10	10	ABB	http://new.abb.com/systems/hvdc/references/hallsjon-the-first-hvdc-light-transmission
2	Gotland, Sweden	1999	50	±80	80	70	ABB	http://new.abb.com/systems/hvdc/references/gotland-hvdc-light
3	Direct Link /TerraNora, Aus.	2000	3x60	±80	132/110	59	ABB	http://new.abb.com/systems/hvdc/references/terranora-interconnector
4	Tjaereborg, Den.	2000	7.2	±9	10.5	4.3	ABB	http://new.abb.com/systems/hvdc/references/tjaereborg
5	Eagle Pass, USA	2000	36	±15.9	132	Back to Back	ABB	http://new.abb.com/systems/hvdc/references/eagle-pass
6	Cross Sound, USA	2002	330	±150	345/138	40	ABB	http://new.abb.com/systems/hvdc/references/cross-sound-cable
7	Murraylink, Australia	2002	220	±150	132/220	180	ABB	http://new.abb.com/systems/hvdc/references/murraylink
8	Troll A, Norway	2005	2x44	±60	56/132	70	ABB	http://new.abb.com/systems/hvdc/references/troll-a
9	Estlink, Finland	2006	350	±150	400/330	31 (underground) 74 (submarine)	ABB	http://new.abb.com/systems/hvdc/references/estlink
10	Caprivi Link, Namibia	2010	300	-350	330/400	950	ABB	http://new.abb.com/systems/hvdc/references/caprivi-link
11	Trans Bay Cable, USA	2010	400	±200	230/138	85	Siemens	http://www.transbaycable.com/
12	Valhall, Norway	2011	78	150	300/11	292	ABB	http://new.abb.com/systems/hvdc/references/valhall
13	Nanhui	2011	18	±30	35/35	8.4 (underground)	C-EPRI	http://www.cepri.com.cn/products/details_39_121.html

S.No	Name	Year Com-missioned	Power (MW)	Voltage DC (kV)	Voltage AC (kV)	Transmission Length (km)	Converter Manufacturer	Reference
14	EWIC: East-West Interconnector, Ireland-UK	2013	500	±200	400	75 (underground) 186 (submarine)	ABB	http://new.abb.com/systems/hvdc/references/east-west-interconnector
15	Nan'ao Island	2013	200, 150, 50	±160	110	Multi-terminal	RXHK, XiDian, NR-Electric	https://www.rxhk.co.uk/corporate/news/multi-terminal-vsc-hvdc/
16	Zhoushan, China	2014	400, 300, 3x100	±200	110/ 220	Multi-terminal, 129 subsea	XuJi Electric/ NR Electric	http://www.cepri.com.cn/aid/details_71_262.html http://www.nrec.com/en/public/doc_resources/2014/09/10/10/540fb4af446fb.pdf
17	Mackinac, USA	2014	200	±71	138	back to back	ABB	http://new.abb.com/systems/hvdc/references/mackinac
18	Skagerrak 4, Norway-Denmark	2014	700	500	400	104 (underground) 140 (submarine) (in bipole with LCC)	ABB	http://new.abb.com/systems/hvdc/references/skagerrak
19	BorWin1, Germany	2015	400	±150	380/ 170	75 (underground) 125 (submarine)	ABB	http://new.abb.com/systems/hvdc/references/borwin1
20	BorWin2, Germany	2015	800	±300	155/ 400	75 (underground) 125 (submarine)	Siemens	http://www.siemens.com/press/pool/de/feature/2013/energy/2013-08-x-win/factsheet-borwin2-en.pdf
21	HelWin1, Germany	2015	576	±250	155/ 400	45 (underground) 85 (submarine)	Siemens	http://www.siemens.com/press/pool/de/feature/2013/energy/2013-08-x-win/factsheet-helwin1-en.pdf
22	INELFE, France-Spain	2015	2x1000	±320	400	65	Siemens	https://www.siemens.com/press/en/events/2015/energymanagement/2015-04- Inelfe.php

S.No	Name	Year Com-missioned	Power (MW)	Voltage DC (kV)	Voltage AC (kV)	Transmission Length (km)	Converter Manufacturer	Reference
23	SylWin1, Germany	2015	864	±320	155/ 400	45 (underground) 160 (submarine)	Siemens	http://www.siemens.com/press/pool/de/feature/2013/energy/2013-08-x-win/factsheet-sylwin1-e.pdf
24	HelWin2, Germany	2015	690	±320	155/ 400	46 (underground) 85 (submarine)	Siemens	http://www.siemens.com/press/pool/de/feature/2013/energy/2013-08-x-win/factsheet-helwin2-en.pdf
25	Dolwin1, Germany	2015	800	±320	380/ 155	90 (underground) 75 (submarine)	ABB	http://new.abb.com/systems/hvdc/references/dolwin1
26	Xiamen, Fujian Province	2015	1000	±320	220	10.7 (Bipolar)	C-EPRI	http://www.cepri.com.cn/products/details_39_679.html
27	Troll 3&4	2015	2x50	±60	66/132	70	ABB	http://new.abb.com/systems/hvdc/references/troll-a
28	Ål-link – Finland	2015	100	±80	110	158 (submarine)	ABB	http://new.abb.com/systems/hvdc/references/aland
29	Luxi, Yunnan Province China	2016	1000	±350	/	Back-to-back	China Southern Grid, RXHK (Yunnan) XD Group/IEECAS (Guangxi)	http://english.iee.cas.cn/rh/rp/201609/t20160905_167435.html
30	NordBalt, Sweden	2016 /17	700	±300	400/ 330	450	ABB	http://new.abb.com/systems/hvdc/references/nordbalt
31	DolWin2, Germany	2017	916	±320	155/ 380	45 (underground) 90 (submarine)	ABB	http://new.abb.com/systems/hvdc/references/dolwin2
32	Maritime Link	2018	500	±200	230/ 345	187 OHL, 170 submarine, bipole	ABB	http://new.abb.com/systems/hvdc/references/maritime-link

S.No	Name	Year Com - miss ione d	Pow er (MW)	Volt age DC (kV)	Volt age AC (kV)	Transmiss ion Length (km)	Conver ter Manufa cturer	Reference
33	Caithness-Moray	2018	800 (120 0)	±320	275/ 400	113 (submarine) + overhead lines	ABB	http://new.abb.com/systems/hvdc/references/caithness-moray-hvdc-link
34	NEMO GB-Belgium	2019	1000	±400	400/ 380	140	Siemens	http://www.nemo-link.com/the-project/overview/
35	Hokkaido-Honshu, Japan	2019	300	+250	275	98 (overhead line) 24 (cable)	Toshiba	https://www.cigre2019.jp/_img/program/The%20New%20Hokkaido-Honshu%20HVDC%20Link.pdf
36	Yu'E	2018 /9	1250 x 4	±420		Back-to-back, 2 parallel pairs	RXHK, XuJi Electric and C-EPRI	https://www.rxhk.co.uk/corporate/news/yue-hvdc-commissioning-complete/
37	BorWin3	2019	900	±320	150/ 400	30 (underground) 130 (submarine)	Siemens	http://www.energy.siemens.com/hq/en/power-transmission/hvdc/references.htm
38	Cobra Cable, Neth.-Denmark	2019	700	±320	400	325	Siemens	http://www.cobracable.eu/
39	Johan Sverdrup Phase 1	2019	100	+/- 80	300/ 33	100	ABB	http://new.abb.com/systems/hvdc/references/johan-sverdrup

Appendix C List of Future HVDC VSC project

S.no	Name	Year to be Commissioned	Power (MW)	Voltage DC (kV)	Voltage AC (kV)	Transmission Length (km)	Converter Manufacturer	Reference
1	DolWin3, Germany	Ready for infeed	900	±320		78 (underground) 83 (submarine)	GE	http://www.tennet.eu/our-grid/offshore-projects-germany/dolwin3/
2	Zhangbei phase 1	2020	3000 x2, 1500 x2	±500			NR Electric, XuJi Electric, C-EPRI and ABB SiFang	https://new.abb.com/systems/hvdc/references/zhangbei
3	Savoie-Piedmont, Italy-France	2020	2x600	±320	/	190	GE	http://www.prysmiangroup.com/staticres/Next-2015-2/interconnecting-france-and-italy-with-hvdc.html
4	Kriegers-Flak Combined Solution	2020	410	±140	150/400	Back-to-back	ABB	https://www.50hertz.com/de/Netz/Netzentwicklung/ProjekteaufSee/CombinedGridSolution KriegersFlakCGS
5	ElecLink, UK-France	2020	1000	±320	400	51	Siemens	http://www.eleclink.co.uk/
6	IFA2 , UK-France	2020	1000	±320	400	240	ABB	http://www.ifa2interconnector.com/
7	Nordlink, Germany-Norway	2020	1400	±525	400/380	54 (underground), 516 (submarine)	ABB	http://new.abb.com/systems/hvdc/references/nordlink
8	ALEGrO	2020	1000	/	/	90	Siemens	http://www.elia.be/en/projects/grid-projects/alegro/alegro-content
9	Trichur-Kerala, India (PK2000)	2020	2x1000	±320		200	Siemens	https://new.siemens.com/global/en/products/energy/high-voltage/high-voltage-direct-current-transmission-solutions/hvdc-plus.html (HVDC references)

S.no	Name	Year to be Commissioned	Power (MW)	Voltage DC (kV)	Voltage AC (kV)	Transmission Length (km)	Converter Manufacturer	Reference
10	SW Link, Sweden (SydVästlänken)	2020	2x600 (2x720)	±300	410	190 underground cable, 60 OHL	GE	https://www.gegridsolutions.com/products/applications/HVDC/South- West-Link-HVDC-case-study-EN-2015-10-Grid-PEA-0574.pdf
11	KunLiuLong / Wudongde CSG China	2020/21	8000,5000 , 3000	800	525	Hybrid Multi-terminal	RXHK, Xuji, TBEA, NARI, Xidian	http://www.rxpe.co.uk/corporate/news/worlds-largest-vsc-hvdc-converter-order/
12	Borwin4	2020+	900	/	/	123	/	http://www.4coffshore.com/windfarms/hvdc-converter-borwin4-converter-cid37.html
13	Zhangbei phase 2	2021	/	/	/	/	/	http://www.cepri.com.cn/release/details_66_745.html
14	Ultranet, Germany	2021	2000	±380	400	340 (hybrid OHL parallel with AC)	Siemens	http://www.energy.siemens.com/hq/en/power-transmission/hvdc/references.htm
15	North Sea Link, Norway-UK	2021	1400	±525	420/400	730 (submarine)	ABB	http://www.northsealink.com/
16	Wando DongJeju Jeju island, Korea	2021	200		154kV	100	ABB	https://new.abb.com/systems/hvdc/references/wando-dongjeju-3-hvdc-converter-station-project
17	Rudong offshore windfarm	2021/2 (estimated)	1100	400	500	100	RXHK, XJ Group	/
18	Johan Sverdrup Phase 2	2022	200	80	300/100	/	Siemens	https://www.statoil.com/en/news/proceeding-with-Johan-Sverdrup-development.html
19	Greenconnector, Switzerland-Italy	2022	1000	±400	/	150	/	http://www.greenconnector.it/en/ index.html
20	Aquind, UK-France	2022	2x1000	±320	400	242	/	http://aquind.co.uk/

S.no	Name	Year to be Commissioned	Power (MW)	Voltage DC (kV)	Voltage AC (kV)	Transmission Length (km)	Converter Manufacturer	Reference
21	EuroAsia Interconnector	2023	1000			Multi-terminal	Siemens	http://www.euroasia-interconnector.com/
22	Viking Link UK-Denmark	2023	1400	±525	400	767	Siemens	http://viking-link.com/
23	FAB Link, UK-France	2023	1400	/	/	2x 180	/	http://www.fablink.net /
24	Western-Isles Scotland	2023	450	±320	150	80 subsea 76 underground	/	https://www.ssen-transmission.co.uk/projects/western-isles/ https://www.ssen-transmission.co.uk/media/1247/ 1454_westernislesneedscasestakeholdersummary.pdf
25	Greenlink, UK-Ireland	2023	500	/	/	160 offshore	/	http://www.greenlinkinterconnector.eu/
26	DolWin 6	2023	900	/	/	/	Siemens	http://www.4coffshore.com/windfarms/tennet-issues-tender-for-dolwin6-nid3589.html
27	Neuconnect, UK-Germany	2023	1400	500	400	720	/	https://www.neuconnect.eu/
28	Creyke Beck A, UK	2023	1200	/	400	~130	ABB	https://doggerbank.com/
29	Creyke Beck B, UK	2023	1200	/	400	~130	ABB	https://doggerbank.com/
30	Gridlink, UK-France	2024	1400			160	/	https://gridlinkinterconnector.com/
31	Northconnect, UK-Norway	2024	1400	±500	400	655	/	http://www.northconnect.no/
32	DolWin 5	2024	900	/	/	100 km (subsea), 30 km (land cable)	ABB	http://www.4coffshore.com/windfarms/hvdc-converter-dolwin5-converter-cid93.html
33	SOO Green Rail	2024	2100	525	345	500	Siemens	http://www.soogreenrr.com/
34	Teeside A, UK	2024/5	1200	/	/	196 onshore, 7 offshore	/	https://doggerbank.com/

S.no	Name	Year to be Commissioned	Power (MW)	Voltage DC (kV)	Voltage AC (kV)	Transmission Length (km)	Converter Manufacturer	Reference
35	Sofia (Teeside B), UK	2024 /5	1400	/	/	195 offshore, 7 onshore	/	https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/838914/cfd-ar3-results-corrected-111019.pdf
36	AREH	2025	6000	/	/	/		http://asianrehub.com/about/
37	Biscay Gulf Link	2025	2200	/	/	370	/	https://www.inelfe.eu/en/projects/bay-biscay
38	Marinus Link	2025	600	/	/	/	/	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan
39	Marex, UK-Ireland	2025	750	/	/	/	/	http://www.organicpowerinternational.com/mares/
40	A-Nord Germany	2025	/	525	/	300	/	https://www.amprion.net/Grid-expansion/Our-Projects/A-North/
41	SuedOstLink	2026	2000	/	/	580	/	http://www.50hertz.com/en/Grid-Extension/Onshore-projects/SuedOstLink
41	Celtic Link	2026	700	320 to 500	220 and 400	575 (500 subsea)	/	http://www.eirgridgroup.com/the-grid/projects/celtic-interconnector/the-project/
42	Norfolk Vanguard, wind farm, UK	Mid-2020s	1800	/	/	/	/	https://group.vattenfall.com/uk/newsroom/news-press-releases/pressreleases/stories/hvdc-for-norfolk-offshore-wind-farms
43	NorfolkBoreas, wind farm, UK	Mid-2020s	1800	/	/	/	/	https://group.vattenfall.com/uk/newsroom/news-press-releases/pressreleases/stories/hvdc-for-norfolk-offshore-wind-farms

S.no	Name	Year to be Commissioned	Power (MW)	Voltage DC (kV)	Voltage AC (kV)	Transmission Length (km)	Converter Manufacturer	Reference
44	Higashi-Shimizu	2027	600	/	/	/	ABB (Hitachi)	https://new.abb.com/news/detail/19701/abb-wins-600-mw-hvdc-order-to-reinforce-japanese-power-supply-through-hvdc-jv-with-hitachi
45	Nautilus	2028	1400					https://www.nationalgrid.com/group/about-us/what-we-do/interconnectors-connecting-cleaner-future
46	Eurolink	2030	1400					https://www.nationalgrid.com/group/about-us/what-we-do/interconnectors-connecting-cleaner-future
47	Icelink	2030 - Under consideration	1000			1000		https://www.nationalgrid.com/group/about-us/what-we-do/interconnectors-connecting-cleaner-future
48	IJMUiden Alpha, Netherlands	2030 – R&D Phase	2000	525				https://www.tennet.eu/news/detail/tennet-develops-first-2gw-offshore-grid-connection-with-suppliers/
49	IJMUiden Beta, Netherlands	2030 – R&D Phase	2000	525				https://www.tennet.eu/news/detail/tennet-develops-first-2gw-offshore-grid-connection-with-suppliers/
50	Shetland	Early planning / possibly VSC	600	/	/	267	/	https://www.ssen-transmission.co.uk/projects/shetland/

S.no	Name	Year to be Commissioned	Power (MW)	Voltage DC (kV)	Voltage AC (kV)	Transmission Length (km)	Converter Manufacturer	Reference
51								
52	BorWin 5	Submitting for approval	900	/	/	/	/	http://www.4coffshore.com/windfarms/hvdc-converter-borwin5-converter-cid96.html
53	SylWin 2	Submitting for approval	900	/	/	/	/	http://www.4coffshore.com/windfarms/hvdc-converter-sylwin2-converter-cid13.html
54	Eastern link, UK	Being considered	2000	/	/	/	/	https://www.ssepd.co.uk/EasternHVDClink/
55	SENER-BC, Mexico	Pre-tender	1500	+/-500		700 (bipolar)	/	http://www.nortonrosefulbright.com/knowledge/publications/163291/ mexicos-first-public-bid-for-electric-transmission-lines
56	Suedlink	In consideration	/	/	/	/	/	https://www.transnetbw.de/de/suedlink
57	AWC, USA	In consideration	1000	±320	/	Multi-terminal	GE	http://atlanticwindconnection.com/new-jersey-energy-link/
58	Tres-Amiga’s, USA	In consideration	3x750	300	345	back to back	GE	http://www.tresamigasllc.com/

Appendix D Control and Protection System of HVDC Converter Station Details

The control and protection systems of the HVDC converters are of key importance. The control and protection system is a complex combination of hardware components like DSP (digital signal processors), computers, I/O boards, transducers etc and software logics embedded in hardware. The overview of HVDC control and protection system is shown in Figure 8-1. Usually the control and protections are redundant to avoid single point of failure. One control computer that hosts the control functions would actively control the converters and with the other redundant control computer would be in hot stand by state. On the other hand, the protection systems might imply either voting system or other type of confirmation logics depending on the vendor and they act in parallel. The I/O boards would collect all the field input and pass on to the control and protection computers. The control/protection computers process the inputs from field and HMI and performs action actions accordingly. The valve controls and valve base electronics receive the information from the control and protection computers and switch the valve units based on the inputs to achieve the order from the control and protection system.

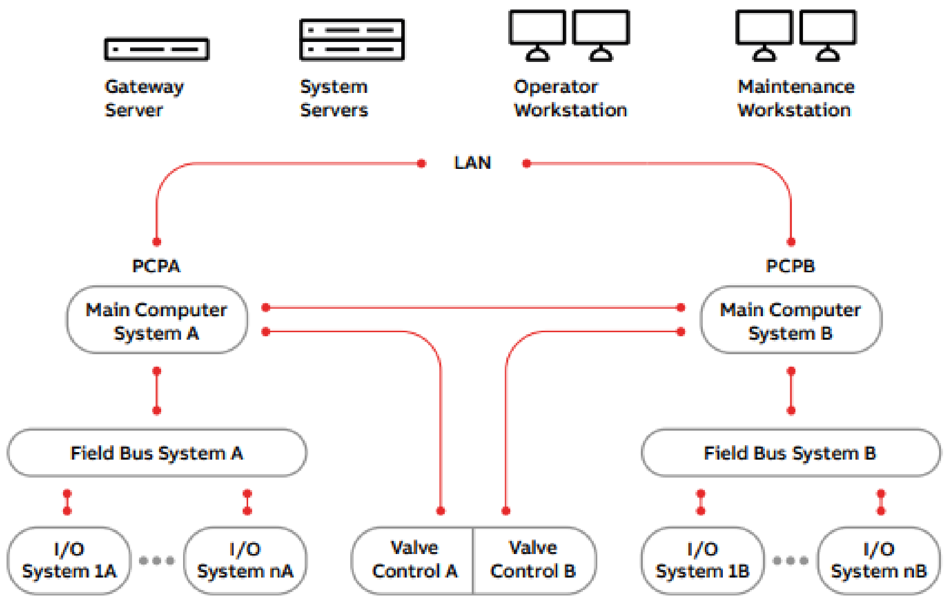


Figure 8-1: Overview of HVDC control and protection system

Source: ABB HVDC Light®- It's time of connect

The controls system also constitutes a TFR (transient fault recorder), HMI (Human Machine Interface), engineering servers, event servers, operator workstation, gateway servers, webservers etc, they are essential parts of all the available control and protection system in the market. In Europe, it is common for the supply of converter hardware and that of the control & protection to be delivered by one and the same vendor.

In the below sections a brief overview of control and protection software functions are provided;

Control Functions

There are various levels of control functions in the HVDC converter;

- **Core/inner controls**

These are the control loops that are responsible to control the valves and decide how the valves should be switched to deliver the ordered Active power/Reactive power/voltage/current. Usually the inner controls of MMC consists of

- Positive Sequence current controller
- Negative Sequence current controller

- **Additional Controls**

These are additional internal controls that may be added for the optimal operation of the converter and directly affect the switching of the valves in the MMC;

- Circulating current control
- Vertical Capacitor voltage balancing control
- Horizontal capacitor voltage balancing control

- **Outer controls**

The outer controllers usually have the following controls that regulate the output of the converter.

- DC voltage Control
- Active Power control
- AC Voltage / Reactive power control

More information on inner / outer / addition controls can be found in [1].

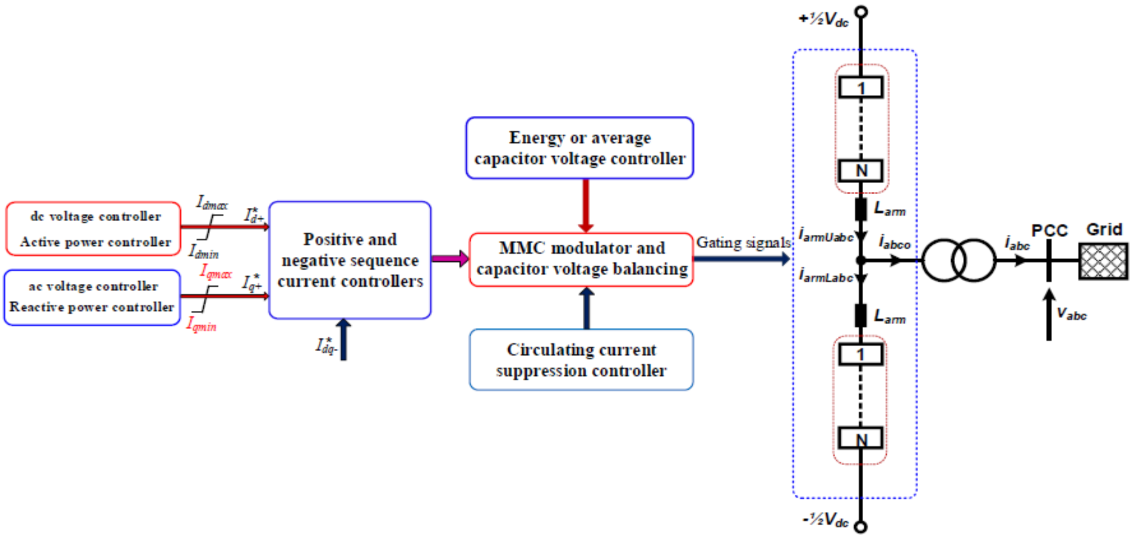


Figure 8-2: Control Block diagram of MMC control

Source: https://www.hvdccentre.com/wp-content/uploads/2019/12/The-National-HVDC-Center-Project-Report-I-MMC-Modelling.pdf

- **Switch gear controls**

These are control logics that are used to control the AC and DC switchgear in the converter station. They have functions like interlock logics, switch gear sequences, HMI/SCADA control interfaces etc. Typically this is characterised by certain switching sequences to energize, re-configure and de-energize different parts of the HVDC system

- **Black start/Islanded Control**

This function is important for offshore windfarm as most of the time the offshore converter would control the offshore ac grid in this mode of control. These controls allow the MMC converter to act as infinite source to the offshore AC network there by creating and controlling the AC voltage/frequency.

- **Special protection systems (The control functions that support the AC grid)**

These are special function that support the AC grid during abnormal conditions like low frequency oscillation, loss of generation/load, change in frequency, interactions etc. Some of them are mentioned below;

- Emergency power control / Runback / Runup

These controls are usually used to compensate the loss of generation / load / line by using either an external power measurement or using digital trip signal as input to initiate their predetermined actions. The actions these functions usually take are fast ramping up or down of the converter power to a pre-set power level.

- Frequency control

This function usually tries and controls the frequency of AC grid within a specified limit by increasing or decreasing the ordered active power by ΔP within a specified dead band. This ΔP can be delivered by the converter almost immediately, thus improving the stability of the ac grid to which the converter is connected. The real power must be provided by the other converter station and hence this function is only applicable to interconnectors if upwards frequency support is required.

- Damping control

The VSC HVDC converter can damp any low frequency oscillation that exists in the ac grid. The damping of these low frequency oscillation is achieved measuring the magnitude and frequency of the existing oscillation and injecting a counter acting modulation by modulating the either active or reactive power that the converter delivers to the ac grid. These are much more effective than the traditional power system stabilizers.

- **Pole / Bipole / Master / wide area control**

Depending on the configuration of the HVDC converter the function like active power control, reactive power control, AC voltage, switching functions, block / deblock etc has be coordinated. If there is only one pole all the above-mentioned controls are done at the pole level, if the connection is in a bipole configuration then a close coordination between the two poles is required to ensure continuity of power during both normal and abnormal operative conditions.

If there are multiple parallel symmetrical monopole or parallel bipoles then for smooth and reliable operation of all the parallel links a higher-level control like a master control would be needed to control all the links in coordinated manner. For a regional - wider area where there are multiple HVDC or HVAC connections a wider area control/monitoring system could be used to coordinate between these links this could improve the safety and security of the offshore wind connections. Johan Sverdrup is one of the projects in where wide area control called Power Dispatch Control System (PDCS) and Power Management System (PMS) is implemented to control the power distribution between the two-parallel offshore HVDC VSC links from different manufacturers. This centralised controls enables power sharing, frequency control, start-up coordination etc.

There are several other control functions that may be included various other components in the converter station like tap changer, valve cooling, Auxiliary services control etc. These controls are essential for normal functioning of the converter station.

Converter Station Protection Functions

The HVDC converter protection systems are normally centralized where all the protection functions are in a central protection panel to facilitate the complex protection and control action. The HVDC converter protection system is a combination of fault detection logic and protection action which together isolates the faulty circuit. There are various protection functions that detects a fault in the converters and other equipment. These protection functions are broadly classified in to three zones AC side protection, Converter protection and DC side protection.

- AC Side protection

The protection functions that protects the AC side equipment like transformer, ACCB, AC filters, pre insertion resistor etc are protected in this zone. Even though the ac equipment could be protected by conventional ac protection relay; their protections are mostly implemented in the central HVDC protection system to coordinate the protection actions that blocks the converter and trips the AC breaker. This protections functions in this zone are shown in **Figure 8-3**.

- Converter Protection

The protection functions that protects the converter valves, converter capacitor and other converter components are in this zone. The converter zone protection needs to be very fast, so these protection functions are implemented in the high-performance digital signal processors and special valve control unit to meet the performance requirement. The protection in this shown in **Figure 8-3**.

- DC side Protection

The protection functions that protects the dc side equipment like DC Pole, DC cable, DC switches etc are in this zone. The protection in this shown in **Figure 8-3**.

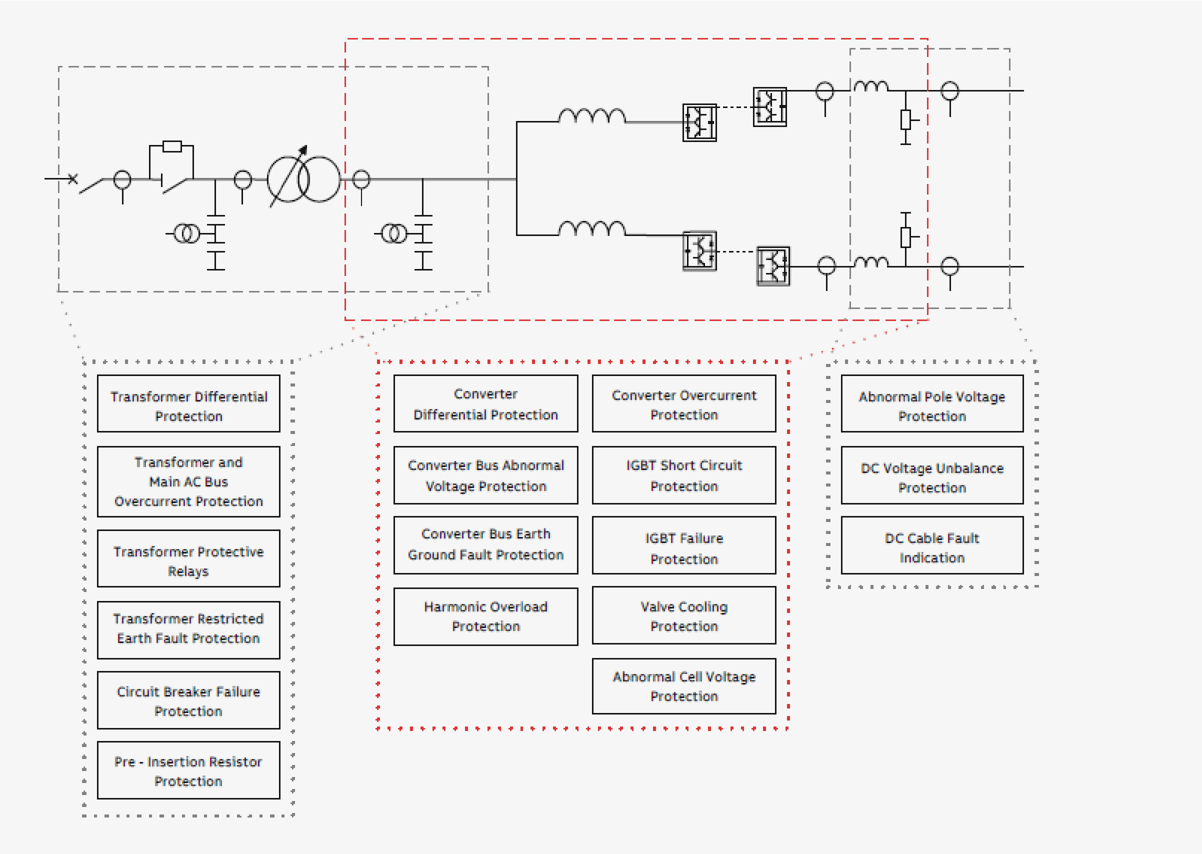


Figure 8-3: HVDC Converter Station Protection system

Source: ABB HVDC Light®- It's time of connect

- Protection Actions

After the protection functions detect the fault, some protection actions must be taken in order to isolate the faulty equipment. Some of the protection actions include;

- Converter blocking – temporary and permanent
- AC breaker trip
- Pole isolations
- Alarms
- Switching sequences

Some of the protection actions depends on the configuration of the HVDC link. In case of symmetrical VSC HVDC link and rigid bipole VSC HVDC link, if there is fault in any converter or the cable the whole link would be blocked and isolated completely from the onshore grid by opening the AC converter breakers disabling the power transfer from the offshore wind farm to the onshore grid. Whereas, in case of bipole HVDC VSC link with low voltage dedicated metallic return cable it is possible to maintain the power transfer in one pole if the other cable or converter is faulty. This continuity of reduced power mainly depends on the design, rating, switching equipment and coordinated protection and control action. This design would mainly improve the availability, safety and security of the link which is discussed in detail inf the conceptual design section.

Appendix E Legal framework changes – process steps

Changes to SQSS Requirements

Governance rules are defined for the SQSS that:

- Require an SQSS Review Panel to be established
- Enable an SQSS Modification Proposal to be raised by a member (of the SQSS Review Panel), the Authority (under normal SQSS governance arrangements) or by a relevant interested party
- Require that the SQSS Review Panel review SQSS Modification Proposals (no time limit defined for this stage where extra data etc may be required) and decide if the Modification Proposal should be referred to an SQSS Workgroup (that reports to the SQSS Review Panel)
    - SQSS Workgroup review must take no longer than 6 months unless otherwise agreed by the SQSS Review Panel
- Require the SQSS Review Panel to consider recommendations and if a Modification Proposal report should be progressed to consultation
- Require the Panel Secretary to issue for consultation a final Modification Proposal report that identifies any SQSS drafting changes that are recommended
- Require the SQSS Review Panel to assess consultation responses and that the Panel Secretary prepares a Final Modification Report which is submitted to the Authority for decision

Changes to Grid Code Requirements

Governance rules are defined for the Grid Code that:

- Require a Grid Code Review Panel ('GCRP') to be established
- Enable a proposal to modify the Grid Code can be made by any User, any Authorised Electricity Operator likely to be materially affected by such a proposal or Citizen's Advice; by the GCRP, or by the Authority (under normal governance arrangements)
    - The Authority also has powers to initiate a Significant Code Review
- Allow GCRP to set up a working group to review Modification Proposals
    - GCRP working group review must take no longer than 6 months unless an extension is justified
- Require the ESO to issue consultation following GCRP discussion of proposed change and working group report
    - standard consultation period is 1 month but extension may be justified
    - Require the ESO, following consideration of consultation responses, to finalise the final Modification Report and submit to the Authority for decision

Changes to Licence Condition Requirements

The Authority has powers to modify licence conditions (under Electricity Act). There are not defined governance arrangements that describe the process steps that need to be followed before a licence change is proposed. The Electricity Act requires that the Authority has to give notice, setting out any licence condition change proposed and reasons for that decision. The notice period must be at least 28 days to allow for representations.

Change Process Summary

For decisions on changes to Codes and SQSS, Ofgem target is to respond to 90% of modification proposals within 5 weeks of receipt of the final report.

Appendix F Conceptual Designs Assumptions

Assumption Topic	Assumption(s)
Boundary Capacity	1) only FES 2019 boundaries showing deficit in 2019 ETYS current capacities vs planned transfer need will be used to influence across boundary locations of interconnected offshore designs, or a design selection valuing such boundary transfer. 2) otherwise the discussed approach will be applied: 1. Identifying the locations where non-integrated solutions are landing today. 2. Identifying where these are subject to existing planning challenge 3. Identifying where these locations have a limit to the non-diversified capacity that can land at them before extensive onshore extension (e.g. new routes locally) would be required. 4. Using the integrated options to minimise/ avoid the onshore connections where planning is challenging. 5. Using the integrated options to also avoid local new routes if considered equivalently contentious. 6. Where this rules out existing onshore locations, as a first approximation move to nearest onshore marshalling locations to minimise excessive DC cabling and similar reinforcement challenges at other substations of limited connectivity to the MITS. 7. focusing development locations where possible
Development Horizon	It is assumed that offshore transmission connections can be built incrementally three (3) years ahead of generator commissioning, and that construction on such new solutions would commence no earlier than 2024, reflecting the requirements of pre-engineering, financing and identifying these options in detail.
European Wind	1) Given current legal and regulatory barriers, hybrid interconnector connections (HVDC and GB offshore wind) will be assumed only. Other areas of design flexibility will be discussed but not included in capacity of designs 2) Given legal and regulatory complexities; connection of both European and GB wind into common interconnector arrangements will not be considered.
Hydrogen Production	Hydrogen is currently assumed to be "off-grid" within the LW scenario. This assumes Hydrogen demand is established via separate dedicated infrastructure and supported by a separate dedicated supply which may include separate dedicated wind capacity. Each of the integrated HVDC offshore designs is flexible to its future connection should it be required in other scenarios via multi-terminal extension.
Interconnectors Capacities Locations	1) data as per Interconnector Register as on 11/06/2020 is used 2) no additional interconnectors beyond the above are assumed 3) load factors are inclusive of any European wind included within a hybrid design
Interconnectors European and Other Growth Factors	1) flexibility for expansion which could be occupied with interconnection with European offshore, interconnection or hydrogen facilities will be considered. 2) specific capacity needs and project applications will not be considered
Codes and frameworks	Existing standards, technical and commercial codes considered as baseline assumptions. Where no standards exist, net effect of conceptual design to not result in an impact to onshore system greater than would result from existing onshore technical codes and standards.

Offshore Wind Capacities	Using the LW Scenario of the National Grid ESO 2020 FES Do not consider specific future schemes
Onshore TO Actions	1) onshore TO reinforcements identified will be considered to the timeframes below within the current TWR report. 2) ESO to nominate locations for associated landing points, otherwise consortia will agree assumption 3) no further reinforcements beyond those discussed below will be considered 4) expected pre-fault utilisation and required post fault boundary capacity within each solution will be provided? Alternatively, will assume 100% used for onshore boundary benefit.

Appendix G Offshore Wind Capacity (2025–2050)

The offshore wind capacity forecasted for the LW scenario in the FES 2020 report is provided in Table A–1 below.

Table A–1 Offshore wind capacity forecasted in 2025-2050 per regional zone.

	Offshore Wind Capacity [MW]				
Flop Zone	**Year 2025**	**Growth →**	**Year 2030**	**Growth →**	**Year 2050**
North Scotland					
T2	1,075	+2,250	3,325	+1,500	4,825
T5	0	+1,750	1,750	+10,000	11,750
T6	1,388		1,388		1,388
Total	2,463	+4,000	6,463	+11,500	17,963
East Scotland					
T4	1,075		1,075		1,075
S6	1,746	+2,300	4,046	+4,200	8,246
Total	2,821	+2,300	5,121	+4,200	9,321
Dogger Bank					
P8	2,827	+2,603	5,427		5,427
Q2	1,700	+500	2,200	+3,200	5,400
Total	4,527	+3,103	7,627	+3,200	10,827
Eastern Regions					
J1	821	+565	1,386	+1,800	3,186
J2	848	+1,720	2,568	+348	2,916
J3	2,965	+5,069	8,034	+4,319	12,353
J5	2,044		2,044		2,044
K4	900		900		900
P7	2,520		2,520	+3,600	6,120
Total	10,098	+7,354	17,452	+10,067	27,519
South East					
B1	400		400	+400	800
C3	630		630		630
C7	300	+340	640		640
Total	1,330	+340	1,670	+400	2,070
North Wales and Irish Sea					
M6	828	+1,000	1,828	+1,580	3,408
M8	0		0	+5,400	5,400
N3	0		0	+4,800	4,800
Q8	178		178		178
R4	182		182		182
R5	1,464		1,464		1,464
Total	2,652	+1,000	3,652	+11,780	15,432
Great Britain					
Total Combined	23,891	+18,097	41,988	+41,147	83,132

Appendix H Annual Wind Energy Production (2025–2050)

The annual wind energy production from the offshore wind capacity forecasted for the LW scenario in the FES 2020 report is provided in Table B–1 below. The calculation assumes a load factor of 43% and therefore does not account for potential differences in wind conditions in each of the zones.

Table B–1 Annual wind energy production in 2025-2050 per regional zone.

	Annual Wind Energy Production [TWh]				
Flop Zone	**Year 2025**	**Growth →**	**Year 2030**	**Growth →**	**Year 2050**
North Scotland					
T2	4.05	+8.48	12.52	+5.65	18.17
T5		+6.59	6.59	+37.67	44.26
T6	5.23		5.23		5.23
Total	9.28	+15.07	24.34	+43.32	67.66
East Scotland					
T4	4.05		4.05		4.05
S6	6.58	+8.66	15.24	+15.82	31.06
Total	10.63	+8.66	19.29	+15.82	35.11
Dogger Bank					
P8	10.65	+9.80	20.44		20.44
Q2	6.40	+1.88	8.29	+12.05	20.34
Total	17.05	+11.69	28.73	+12.05	40.78
Eastern Regions					
J1	3.09	+2.13	5.22	+6.78	12.00
J2	3.19	+6.48	9.67	+1.31	10.98
J3	11.17	+19.09	30.26	+16.27	46.53
J5	7.70		7.70		7.70
K4	3.39		3.39		3.39
P7	9.49		9.49	+13.56	23.05
Total	38.04	+27.70	65.74	+37.92	103.66
South East					
B1	1.51		1.51	+1.51	3.01
C3	2.37		2.37		2.37
C7	1.13	+1.28	2.41		2.41
Total	5.01	+1.28	6.29	+1.51	7.80
North Wales and Irish Sea					
M6	3.12	+3.77	6.89	+5.95	12.84
M8	0		0	+20.34	20.34
N3	0		0	+18.08	18.08
Q8	0.67		0.67		0.67
R4	0.69		0.69		0.69
R5	5.51		5.51		5.51
Total	9.99	+3.77	13.76	+44.37	58.13
Great Britain					
Total Combined	89.99	+68.17	158.16	+154.99	313.14

Appendix I Offshore Wind Power Injections

The active power injections used in the power system analysis are estimated from the growth of offshore wind capacity between 2025-2030 and 2030-2050. The power injections per regional zone for the counterfactual and integrated designs are detailed below.

North Scotland

Active power injections of the offshore wind capacity growth between 2025-2030:

- **Counterfactual:** 1.58 GW to Drax (P4) (via Peterhead-Drax HVDC interconnector), 0.52 GW to Beauly (T1) and 0.70 GW to Peterhead (T2) (via Spittal-Peterhead HVDC interconnector).
- **Integrated:** 2.58 GW to Drax (P4) (via Peterhead-Drax HVDC interconnector) and 0.22 GW to Peterhead (T2).

Active power injections of the offshore wind capacity growth between 2030-2050:

- **Counterfactual:** 1.05 GW to Peterhead (T2) (via HVDC connection from Shetland area), 5.70 GW to Spittal (T5) and 1.30 GW to Keith (T6).
- **Integrated:** 0.55 GW to Peterhead (T2), 2.60 GW to Kintore (T2), 1.30 GW to Keith (T6) and 3.60 GW to Cottam (K5) (via Kintore-Cottam HVDC interconnector).

East Scotland

Active power injections of the offshore wind capacity growth between 2025-2030:

- **Counterfactual:** 0.50 GW to Cockenzie (S6) and 1.10 GW to Torness (S6).
- **Integrated:** 1.60 GW to Blyth (Q4).

Active power injections of the offshore wind capacity growth between 2030-2050:

- **Counterfactual:** 1.47 GW to Cockenzie (S6) and 1.47 GW to Torness (S6).
- **Integrated:** 0.85 GW to Cockenzie (S6), 1.05 GW to Torness (S6) and 1.00 GW to Blyth (Q4).

Dogger Bank

Active power injections of the offshore wind capacity growth between 2025-2030:

- **Counterfactual:** 0.52 GW to Creyke Beck (P8), 1.30 GW to Keadby (P8) and 0.35 GW to Lackenby (Q2).
- **Integrated:** 1.82 GW to Walpole (J1) and 0.35 GW to Lackenby (Q2).

Active power injections of the offshore wind capacity growth between 2030-2050:

- **Counterfactual:** 2.24 GW to Lackenby (Q2).
- **Integrated:** 1.11 GW to Killingholme (P7) and 1.13 GW to Lackenby (Q2).

Eastern Regions

Active power injections of the offshore wind capacity growth between 2025-2030:

- **Counterfactual:** 0.40 GW to Walpole (J1), 0.60 GW to Bramford (J2), 0.60 GW to Sizewell (J2), 0.65 GW to Necton (J3) and 2.90 GW to Norwich Main (J3).
- **Integrated:** 2.58 GW to Grain (C3), 1.42 GW to Walpole (J1), 0.60 GW to Bramford (J2) and 0.60 GW to Sizewell (J2).

Active power injections of the offshore wind capacity growth between 2030-2050:

- **Counterfactual:** 1.25 GW to Walpole (J1), 0.25 GW to Sizewell (J2), 3.00 GW to Norwich Main (J3) and 2.50 GW to Killingholme (P7).
- **Integrated:** 0.98 GW to Grain (C3) (via NeuConnect HVDC), 1.05 GW to Grain (C3) (via Southern Link HVDC), 2.64 GW to Kemsley (C3), 1.60 GW to Tilbury (C1), 0.21 GW to Richborough (C7) (via Nemo Link HVDC) and 0.56 GW to Sellindge (C4) (via Eleclink HVDC).

South East

Active power injections of the offshore wind capacity growth between 2025-2030:

- **Counterfactual:** 0.21 GW to Richborough (C7).
- **Integrated:** 0.21 GW to Richborough (C7).

Active power injections of the offshore wind capacity growth between 2030-2050:

- **Counterfactual:** 0.28 GW to Bolney (B1).
- **Integrated:** 0.28 GW to Richborough (C7).

North Wales and Irish Sea

Active power injections of the offshore wind capacity growth between 2025-2030:

- **Counterfactual:** 0.70 GW to Pentir (M6).
- **Integrated:** 0.70 GW to Pembroke (H6).

Active power injections of the offshore wind capacity growth between 2030-2050:

- **Counterfactual:** 1.20 GW to Pentir (M6), 3.70 GW to Wylfa (M8) and 3.35 GW to Birkenhead (N3).
- **Integrated:** 0.62 GW to Pembroke (H6), 2.58 GW to Cilfynydd (H6), 1.32 GW to Wylfa (M8), 1.85 GW to Penwortham (R4) and 1.85 GW to Heysham (R5).

Appendix J Glossary

Glossary of terms (with reference to https://global.abb/group/en/media/resources/glossary#b as appropriate).

AC transmission

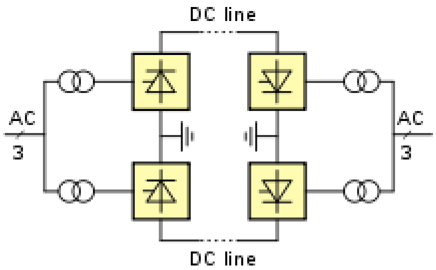
Alternating current (AC): Alternating current is a form of electricity in which the current alternates in direction (and the voltage alternates in polarity) at a frequency defined by the generator (usually between 50 and 60 times per second, ie, 50 - 60 hertz). AC was adopted for power transmission in the early days of electricity supply because it had two major advantages over direct current (DC): its voltage could be stepped up or down according to need using transformers (see Transformer), and it could be interrupted more easily than DC. Neither advantage is as relevant today as it once was because power electronics can solve both issues for DC.

Back-to-back connections

In HVDC terms, links used to connect neighboring grids are often referred to as "back-to-back" connections, indicating that the distance between the two grids is minimal. Such connections are able to link independent power grids, including those operating at different frequencies or voltage, and enable power to flow from one grid to another. A DC/DC convertor is a form of back to back connection where there is no intermediate conversion to AC power.

Bipole HVDC transmission

In bipolar HVDC transmission a pair of conductors is used, each at a high potential with respect to ground, in opposite polarity (i.e -kV and +kV). There are a number of advantages to bipolar transmission which can make it an attractive option.



Block diagram of a bipolar system that also has an earth return

- Under normal load, negligible earth-current flows, as in the case of monopolar transmission with a metallic earth-return. This reduces earth return loss and environmental effects.
- When a fault develops in a line, with earth return electrodes installed at each end of the line, approximately half the rated power can continue to flow using the earth as a return path, operating in monopolar mode.
- Since for a given total power rating each conductor of a bipolar line carries only half the current of monopolar lines, the cost of the second conductor is reduced compared to a monopolar line of the same rating.

A bipolar system may also be installed with a metallic earth return conductor.

Submarine cable installations initially commissioned as a monopole may be upgraded with additional cables and operated as a bipole.

A bipolar scheme can be implemented so that the polarity of one or both poles can be changed. This allows the operation as two parallel monopoles. If one conductor fails, transmission can still continue at reduced capacity. Losses may increase if ground electrodes and lines are not designed for the extra current in this mode. To reduce losses in this case, intermediate switching stations may be installed, at which line segments can be switched off or parallelized.

Black-start capability

The ability of a power system (a generator or grid subsection) to restart after a blackout, independently of the larger grid, For example, HVDC systems can be fitted with small diesel generators to provide auxiliary power that can be operational almost immediately in the event of a blackout. This power enables voltage control to be established and normal operations to be resumed quickly.

Capacitor (also referred to as a condenser)

A multi-purpose device that can store electrical charge in the form of an electric field. It is used, for example, for power factor correction in (inductive) AC circuits. Capacitors are used to buffer electricity (smooth out peaks) and to guard against momentary voltage losses in circuits (when changing batteries, for example).

Converter

An electrical device, comprising a rectifier and inverter, used to alter the voltage and frequency of incoming alternating current in an electrical system. The term may also refer to inverters, rectifiers or frequency converters.

Converter station:

Special equipment is needed to convert electricity from alternating current (AC) to direct current (DC), or vice versa. High-voltage DC (HVDC) converter stations use power electronic devices called thyristors to make these conversions.

Direct current (DC)

This is electrical current that does not alternate (see Alternating current), the electrons flow through the circuit in one direction. As a result, DC does not generate reactive power (see Reactive Power). This means that, in a DC system, only real (or active) power is transmitted, making better use of the system's capacity. In order to transmit electrical power as DC, the alternating current generated in the power plant must be converted into DC. At the other end of the process, the DC power must be converted back into AC, and fed into the AC-transmission or distribution network. The transmission of DC current has very low losses. In the conversion between the two forms of power, known as rectification, incurs additional power losses and so it is worthwhile only when these losses are less than would be incurred by AC transmission, ie, over very long distances (~1000 km for overhead lines, ~100 km for underwater). The other situation in which DC transmission is advantageous is when connecting asynchronous grids, ie, where adjoining electricity grids have different frequencies (eg, 50 or 60 Hz, as happens in some parts of Brazil and the United States).

FACTS (Flexible Alternating Current Transmission Systems)

Refers to a group of technologies that enhance the security, capacity and flexibility of power transmission and distribution systems. The technologies can be installed in new or existing power transmission and distribution lines. Examples of FACTS devices are: Static var compensation (SVC), uses an electrical device (see Static var compensator) to regulate and stabilize voltage in bulk power systems.

Harmonics: Generally, harmonics are oscillations in the base power frequency. In electrical AC systems, the base frequency is typically 50 or 60 hertz (Hz) and harmonics occur in multiples of this, for example 100 Hz, 150 Hz, 200 Hz, etc. where the base frequency is 50 Hz. Harmonics occur whenever there is a disturbance of the voltage or current, eg, if the current is interrupted or if AC current is synthesized in a converter. The problem with harmonics is that electrical devices may react differently when exposed to a different frequency than the one they are designed for, which may cause damage. Harmonics are an increasing problem in power systems as most power electronics solutions cause harmonics. Harmonics can be reduced by the use of power filters.

High-voltage direct current (HVDC)

A technology developed by the 1950s to move large amounts of power over substantial distances - typically by overhead transmission lines, but also by way of submarine cables. Transmitting DC power over long distances is more efficient than AC transmission (see Direct current and Transmission and distribution) and is a cost-effective method of connecting two asynchronous grids (grids operating at different frequencies). An HVDC system takes electrical power from an AC network, converts it to DC at a converter station and transmits it to the receiving point by line or cable, where it is turned back into AC by using another converter. The conversion is carried out with high-power, high-voltage electronic semiconductor valves. These valves are controlled by a computer system, so the amount of transmitted power and also the direction of transmitted power can be precisely controlled. Because HVDC transmits only active (real) power, no line capacity is wasted on transmitting reactive power. This means that the same power can be transmitted over fewer (or smaller) transmission lines than would be required using AC, and less land is needed to accommodate the lines. HVDC induces minimal magnetic fields, when cabled lower separation is required between circuits.

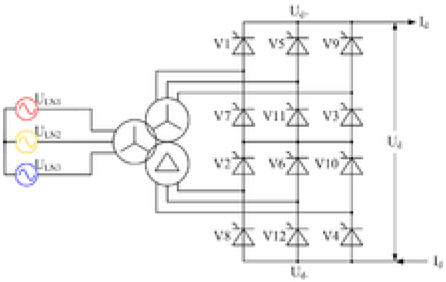
Inverter

An electrical device operating in a control mode for converting direct current (DC) into alternating current (AC).

Line-commutated converters

Most of the HVDC systems in operation today are based on line-commutated converters.

The basic LCC configuration uses a three-phase bridge rectifier or six-pulse bridge, containing six electronic switches, each connecting one of the three phases to one of the two DC rails. A complete switching element is usually referred to as a valve, irrespective of its construction. However, with a phase change only every 60°, considerable harmonic distortion is produced at both the DC and AC terminals when this arrangement is used.



A twelve-pulse bridge rectifier

An enhancement of this arrangement uses 12 valves in a *twelve-pulse bridge*. The AC is split into two separate three phase supplies before transformation. One of the sets of supplies is then configured to have a star (wye) secondary, the other a delta secondary, establishing a 30° phase difference between the two sets of three phases. With twelve valves connecting each of the two sets of three phases to the two DC rails, there is a phase change every 30°, and harmonics are considerably reduced. For this reason, the twelve-pulse system has become standard on most line-commutated converter HVDC systems built since the 1970s.

With line commutated converters, the converter has only one degree of freedom – the *firing angle*, which represents the time delay between the voltage across a valve becoming positive (at which point the valve would start to conduct if it were made from diodes) and the thyristors being turned on. The DC output voltage of the converter steadily becomes less positive as the firing angle is increased: firing angles of up to 90° correspond to rectification and result in positive DC voltages, while firing angles above 90° correspond to inversion and result in negative DC voltages. The practical upper limit for the firing angle is about 150–160° because above this, the valve would have insufficient *turnoff time.*

Low Frequency AC (LFAC)

This refers to an alternating current at a lower frequency. An AC current alternates in direction every half cycle, which for a 50 Hz GB frequency corresponds to a 10ms time period, with a full cycle being 20 ms. Unlike conventional AC, Low fr equency AC operates at a slower frequency, changing direction over, for example, every 30ms for a 16.6Hz system and having an LFAC cycle similarly longer. The length of an AC oscillatory cycle is critical for system measurements, associated control and protection activity, with a lower AC frequency leading to longer times for operational actions such as fault interruption (with faults containing a higher stored energy due to the longer time of clearance) and slower control for example in frequency response. LFAC changes the properties of AC circuits whose impedance to power flow are frequency sensitive, and as a result can enable solutions with longer AC cables to be consider than would otherwise be the case. This same approach also shifts harmonic emissions and has therefore potential benefits in managing power quality issues. LFAC requires a frequency convertor to interface with other, non-low frequency systems.

Medium Voltage AC

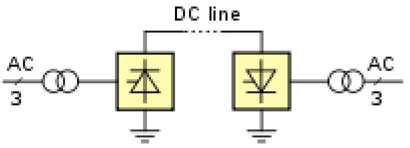
In GB voltages at or below 132 kV may be referred to as MVAC. Normally refers to 66 kV and below which are not typically transmission voltages

Medium Voltage DC

Refers to voltages of c. 50 kV and lower where less complex convertor solutions may be available for the transmission of nominally more limited scales of DC power.

Monopole

In a monopole configuration one of the terminals of the rectifier is connected to earth ground. The other terminal, at high voltage relative to ground, is connected to a transmission line. The earthed terminal may be connected to the corresponding connection at the inverting station by means of a second conductor.



Block diagram of a monopole system with earth return

If no metallic return conductor is installed, current flows in the earth (or water) between two electrodes. This arrangement is a type of single-wire earth return system.

The electrodes are usually located some tens of kilometers from the stations and are connected to the stations via a medium-voltage electrode line. The design of the electrodes themselves depends on whether they are located on land, on the shore or at sea. For the monopolar configuration with earth return, the earth current flow is unidirectional, which means that the design of one of the electrodes (the cathode) can be relatively simple, although the design of anode electrode is quite complex.

For long-distance transmission, earth return can be considerably cheaper than alternatives using a dedicated neutral conductor, but it can lead to problems such as:

Electrochemical corrosion of long buried metal objects such as pipelines

- Underwater earth-return electrodes in seawater may produce chlorine or otherwise affect water chemistry,
- An unbalanced current path may result in a net magnetic field, which can affect magnetic navigational compasses for ships passing over an underwater cable
- For these reasons these approaches are not used in GB

These effects can be eliminated with installation of a metallic return conductor between the two ends of the monopolar transmission line. Since one terminal of the converters is connected to earth, the return conductor need not be insulated for the full transmission voltage which makes it less costly than the high-voltage conductor. The decision of whether or not to use a metallic return conductor is based upon economic, technical and environmental factors.

Multi-terminal systems

The most common configuration of an HVDC link consists of two converter stations connected by a DC circuit

Multi-terminal HVDC links, connecting more than two points, are rare. The configuration of multiple terminals can be series, parallel, or hybrid (a mixture of series and parallel). Parallel configuration tends to be used for large capacity stations, and series for lower capacity stations. An example is the 2000 MW Quebec - New England Transmission system opened in 1992, which is currently the largest multi-terminal HVDC system in the world.

Multi-terminal systems are difficult to realize using line commutated converters because reversals of power are effected by reversing the polarity of DC voltage, which affects all converters connected to the system. With Voltage Sourced Converters, power reversal is achieved instead by reversing the direction of current, making parallel-connected multi-terminals systems much easier to control. For this reason, multi-terminal systems are expected to become much more common in the near future.

Symmetrical monopole

An alternative to a monopole with an earthed return, is to use two high-voltage conductors, operating at about half of the DC voltage, with only a single converter at each end. In this arrangement, known as the *symmetrical monopole*, the converters are earthed only via a high impedance and there is no earth current. The symmetrical monopole arrangement is uncommon with line-commutated converters but is very common with Voltage Sourced Converters when cables are used. It is attractive given the lower voltage of cables required to support the same capacity and its associated benefits in convertor scale over a simple monopole design.

Reactive power

It is a concept that describes the loss of power in a system resulting from the production of electric and magnetic fields in it. Reactive loads in a power system drop voltage and draw current, which creates the impression that they are using up power, when they are not. This "imaginary power" or "phantom power" is called reactive power, and is measured in Volt-Amps-Reactive (VAR). Reactive power is significant because it must be provided and maintained to ensure continuous, steady voltage on transmission networks. Reactive power is produced for maintenance of the system, and not for end-use consumption. If elements of the power grid cannot get the reactive power they need from nearby sources, they will pull it across transmission lines and destabilize the grid. In this way, poor management of reactive power can cause major blackouts.

Short circuit

An electric contact between parts of an electric circuit, which causes a very high current, increases in temperature and potentially fire, if the circuit is not properly protected. This can occur if two live wires come into contact with each other, perhaps because of worn insulation. The term is also used when defining the safe operating conditions for electrical devices. If a device is said to have a short-circuit resilience of 400 amps (A), that means that it can be subjected to up to 400 A before it will shut itself down.

Shunt reactors

Shunt reactors are used in AC high voltage energy transmission systems to stabilize the system voltage during load variations. The shunt reactor can be regarded electrically as a large coil connected between the line and ground to absorb reactive power in the system. This function is especially important at high voltages, typically over 130 kilovolts (kV), and long transmission lines. Cable systems require even more compensation of reactive power, also at lower system voltage due to the high capacitance of the cable. Besides stabilizing the system voltage, the shunt reactor increases the active or the useful power transmitted in the system.

Thyristor

A thyristor is a semiconductor device used in electrical systems, such as HVDC installations, as a high-speed, high-power switch, capable of turning power supplies of many megawatts on within a split second. Thyristors are a component used in inverters and rectifiers.

Voltage-source converters (VSC)

Widely used in motor drives since the 1980s, voltage-source converters started to appear in HVDC in 1997 with the experimental Hellsjön–Grängesberg project in Sweden. By the end of 2011, this technology had captured a significant proportion of the HVDC market.

The development of higher rated insulated-gate bipolar transistors (IGBTs), gate turn-off thyristors (GTOs) and integrated gate-commutated thyristors (IGCTs), has made smaller HVDC systems economical. The manufacturer ABB Group calls this concept HVDC Light, while Siemens calls a similar concept HVDC PLUS (Power Link Universal System) and Alstom call their product based upon this technology HVDC MaxSine. They have extended the use of HVDC down to blocks as small as a few tens of megawatts and overhead lines as short as a few dozen kilometers. There are several different variants of VSC technology: most installations built until 2012 use pulse-width modulation in a circuit that is effectively an ultrahigh-voltage motor drive. Current installations, including HVDC PLUS and HVDC MaxSine, are based on variants of a converter called a Modular Multilevel Converter (MMC).

Multilevel converters have the advantage that they allow harmonic filtering equipment to be reduced or eliminated altogether. By way of comparison, AC harmonic filters of typical line-commutated converter stations cover nearly half of the converter station area.

With time, voltage-source converter systems will probably replace all installed simple thyristor-based systems, including the highest DC power transmission applications.

Wide-area monitoring system (WAMS):

WAMS is an advanced early-warning technology for power grids that helps operators prevent system instabilities and overloads, as well as cascade tripping that leads to power blackouts. It comprises a series of phasor measurement units, set up in strategic positions around the grid. These monitor stresses (loads and temperatures) on the power lines and send data back to a central control station via a GPS satellite link. This allows operators to identify problems at an early stage and prevent widespread disruption of the grid (ultimately rolling blackouts). WAMS is used in conjunction with phase shifting transformers to protect and stabilize power grids.

Appendix K Abbreviations

AC	Alternating Current
CAPEX	Capital expenditure
CBA	Cost-Benefit Analysis
CCS	Carbon Capture and Storage
DC	Direct Current
DCCB	DC Circuit Breaker
ECC	European Connection Conditions
EENS	Expected energy not served
ESO	Electricity System Operator
ETYS	Electricity Ten Year Statement
FACTS	Flexible AC Transmission System
FES	Future Energy Scenarios
GB	Great Britain
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
KPI	Key Performance Indicator
LCC	Line Commutated Converter
LFAC	Low Frequency AC
LOLE	Loss of load expectation
LVDC	Low voltage DC
LW	Leading the Way
MITS	Main Integrated Transmission System
NETS	National Electricity Transmission System
NOA	Network Options Assessment
NPV	Net Present Value
OFTO	Offshore Transmission Owner
OPEX	Operational expenditure

OWF	Offshore Wind Farm
P2X	Power to X (any other media than electricity, e.g. heat, gas)
RES	Renewable Energy Sources
SCL	Short Circuit Level
SQSS	Security and Quality of Supply Standard
SRF	System Requirement Form
STATCOM	Static Synchronous Compensator
TEC	Transmission Entry Capacity
TO	Transmission Owner
TRL	Technology Readiness Level
TSO	Transmission System Operator
UK	United Kingdom
VSC	Voltage Source Converter
WDZ	Wind Development Zones