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The Renaissance of HVDC for a Low Carbon Future

By Harry K. Brunt and Joseph Lam*

In this article the authors explore the resurgence of high voltage direct current transmission technology and its relevance in a world that is transitioning to renewable power and adopting electric vehicles and heating and reducing its reliance on fossil fuels. The first part of this article considers the benefits of the technology and some of the challenges it creates for investors, regulators and policy makers. The second part of this article looks at how investments in high voltage direct current transmission projects might be structured, including by examining examples of projects that have been successfully implemented.

PART 1 – THE TECHNOLOGY AND ITS BENEFITS AND CHALLENGES FOR INVESTORS AND REGULATORS

Anyone who has read a little history or seen the 2017 film The Current War knows that George Westinghouse's alternating current (AC) won the late nineteenth century battle against Thomas Edison's purportedly safer direct current (DC) alternative – the evidence is plain to see in our own homes. Ultimately, in 1892 the Edison Electric Light Company merged with its main AC competitor, Thomson-Houston, to form General Electric.[1]

A principal reason for AC's early success was that transmission of electricity over significant distances is inefficient at low voltages: the energy wasted as heat in a conductor is proportional to the square of the current; and, for any given quantity of power transmission, the current is inversely proportional to voltage. Therefore, the higher the voltage the lower the energy losses become.

High transmission voltages are therefore desirable, with lower voltages at the point of use for safety reasons. A hundred odd years ago there was no efficient solution to convert DC from low to high voltage. AC on the other hand could be easily stepped up in voltage using a simple and cheap transformer, which has no moving parts. The invention of the induction motor also allowed AC to be used to power heavy industrial machinery, although DC still had many advantages over AC, such as being easier to use for railways and to control variable speed, asynchronous motors.

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[1] Today, General Electric's successor GE Vernova is once again championing DC in the form of high voltage conversion systems to support HVDC cables that can transfer electricity point-to-point or from offshore wind farms to shore.

DC'S RENAISSANCE

More recently, over the past few decades, DC systems and in particular high voltage DC (HVDC) have enjoyed a renaissance, owing to their offering a number of benefits. HVDC transmission involves purely reactive power with no reactive power component and associated losses, which ultimately limits the length of high voltage AC power lines. HVDC transmission lines are technically the only viable solution for submarine or terrestrial buried electrical cables longer than a few tens of kilometers because of the capacitance of the insulated cables (which have to be charged and discharged each cycle, causing significant energy losses).

DC transmission also allows two asynchronous AC transmission grids (e.g., operating at different frequencies in different territories) to be interconnected. For the same reason, HVDC is typically also used to connect offshore wind farms, with the additional advantage that wind turbine generators can operate asynchronously with the onshore grid and, as such, at an optimum level of efficiency for any given wind condition.

Photovoltaic panels are only capable of directly producing DC output, and an *inverter* therefore has to be used to generate a three-phase high voltage AC output which is synchronized with the transmission grid. The same is true of storage batteries and other non-traditional power generation sources that do not use spinning generators.

Inverters use high-power, solid-state devices (typically, insulated gate bipolar transistors (IGBTs)) which switch on and off in a modulated configuration, controlled by sophisticated electronics, to produce a sinusoidal output which can be stepped up via a transformer to high voltage AC (HVAC) for transmission. Similar conversion devices can be configured to step-up the lower voltage DC output of a solar panel array or battery energy storage system directly to HVDC suitable for transmission or indeed to convert HVAC to HVDC.

The drive towards increased offshore wind power generation in many countries, including the UK, where generation sources are located far from where energy is required by consumers, provides a good illustration of the advantages and benefits of HVDC solutions. It would be impractical to build new transmission lines linking Scotland with England, such as the Eastern Green Links, without using subsea cables;[2] and, as noted above, HVDC is the

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[2] The environmental impact of using terrestrial overhead transmission lines for the entire length of one of the Eastern Green Links would likely be prohibitive. Terrestrial underground cables are estimated by Scottish Power to cost between five and ten times as much as overhead

only viable way to transmit electricity over long distances via such cables, which will necessarily have to be several hundred kilometers long.[3]

Several planned projects also involve long distance terrestrial buried HVDC cables, as the impact on the landscape is minimal once the work is completed and the land corridor restored – and there may be significant local resistance to new terrestrial overhead cables.

As the proportion of electricity generated by renewables increases, and as battery storage systems become more widespread, the arguments for using HVDC transmission more generally, as opposed to high voltage AC, become more compelling. If we take into account the future expansion of electric vehicle (EV) use and the need for fast battery charging stations, there are additional arguments in favor of HVDC systems. EV batteries require relatively low voltage but high current DC to charge rapidly. As such, a battery charging station array could in principle be supplied locally by DC or AC. There is no inherent technical requirement for AC as opposed to DC (or vice versa) and in principle either could be used with the appropriate conversion equipment; but what HVDC offers is potentially greater efficiencies and economies on a wider scale, which are discussed below.

WHY USE HVDC SYSTEMS?

HVDC transmission systems offer a number of advantages over HVAC:

1. HVDC requires only two conductors, whereas HVAC needs three to support three phases, reducing costs and potentially requiring narrower land corridors.
2. HVDC power transmission losses may be lower than 0.3% per 100 km, which is 30% to 40% lower than losses for HVAC at an equivalent voltage, for a number of reasons:
    - AC suffers from a skin effect whereby only the outer part of the cable conducts current, which is avoided in DC transmission – the result is that for a given conductor size and energy losses, HVDC systems can transmit higher current over longer distances;

transmission lines; however, submarine cables are also significantly more expensive than overhead transmission lines.

[3] For example, Eastern Green Link 1 (EGL1) is almost 200 km long (including 176 km of subsea cable) and when completed will link East Lothian with County Durham, allowing the transfer of 2GW of electrical power. The UK is planning a series of such links, including four Eastern Green Links, and the Western HVDC Link between Scotland and North Wales (with a capacity of 2.25 GW) was completed in 2019.

- ○ HVDC lines operate continuously at peak voltage (which is determined by the design of the transmission line insulators and towers, among other things), whereas HVAC is sinusoidal – and while the crests of the sine wave are naturally at peak voltage, the effective average voltage (and corresponding current) is the root mean square value (RMS), which is only 0.7 times the peak voltage; the net effect is to increase the power transmission capacity of an HVDC system relative to HVAC; and
- ○ DC carries only active power, whereas AC transfers both active and reactive power.

3. HVDC transmission lines/interconnectors are asynchronous, enabling connections between unsynchronized power sources, such as two grids operating at different frequencies, phases or voltages.
4. As noted above, HVDC is the only practical option for undersea cables longer than around 50 km.

DRAWBACKS OF HVDC

HVDC does have certain drawbacks:

- HVDC systems may be less reliable, have lower availability and be more expensive to maintain than HVAC, owing to their greater complexity;
- Additional complexity also increases the relative cost for shorter-distance transmission as compared with HVAC;
- Converter stations are required at each end of HVDC cables to convert from AC to DC and back again (assuming the source and load are AC) – these are expensive and may introduce relatively higher energy losses for shorter distance lines – but as noted above in the case of DC generation sources (such as solar) and DC loads (such as battery chargers), conversion equipment is also required if an HVAC transmission line is used; and
- HVDC switching and breaker systems are more difficult to design and implement because, unlike AC which has zero current twice every cycle (at which point the circuit can be broken safely), HVDC current is continuous and a simple mechanical breaker cannot therefore be used because it would suffer potentially destructive arcing.

Weighing up the pros and cons, it is generally considered that for overhead transmission lines, HVDC transmission becomes cost effective above a minimum critical distance.

Bringing increased future reliance on renewable power generation, electrical vehicles, battery storage and heat pumps into the equation suggests that there are potential benefits in developing wide area HVDC super grids. These might help to mitigate the intermittency of renewable power sources by averaging and smoothing the outputs of geographically dispersed generation facilities.

It also seems likely that substantial investment in upgrading of transmission systems will be required to support any move towards the widespread use of electric vehicles and the adoption of heat pumps for heating in place of natural gas. Existing transmission systems are entirely inadequate and would create severe bottlenecks. The United Kingdom is already seeing the impact of planning for such changes in its "Great Grid Upgrade" through the procurement of the Eastern Green Links (EGL 1 to EGL 4) between Scotland and England, in the case of EGL3 and EGL4 reaching as far as East Anglia.

IMPLICATIONS FOR INVESTORS, REGULATORS AND POLICYMAKERS[4]

Given the potential attractiveness of HVDC solutions, those responsible for investing in grid infrastructure (such as integrated utilities or unbundled network companies) may need to keep their investment programs under review. Changes in the nature of the grid and the technologies connected to it may mean that HVDC becomes a contender to traditional AC network investments where the conditions are right, such as where power generated by non-synchronous generators (e.g., wind and solar farms) is being moved over long distances and in particular where it is impractical to build new conventional terrestrial transmission lines.

As noted above, this is already happening today in the UK. While many early links to offshore windfarms relied on AC technology, ENTSO-E's Offshore Network Development Plan[5] (ONDP) has adopted HVDC as a standard transmission technology, with 525 kV VSC converter technology. Following the precedent of the Eastern Green Link projects, it looks likely that 525 kV HVDC may become the standard for the significant GB offshore network investment planned in the North Sea, as well as interconnectors (for example, Neuconnect).

The EGL projects were signed off after formal reviews of their costs and benefits, conducted separately from the normal regulatory regime for the GB transmission network. This underlines that considering the full range of technologies and making optimum choices with the right long-term strategic benefits may require extraordinary action by policymakers and regulators.

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[4] Comments on regulatory aspects were kindly provided by Dan Roberts of Frontier Economics.

[5] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/ONDP2024/web_entso-e_ONDP_PanEU_240226.pdf.

Traditionally, network regulation typically aims to incentivize grid companies to do what is cheapest, but regulatory incentives are typically less effective than those from competitive markets. For example, if new technologies carry more of an operational risk than the traditional options, and grid operators believe that regulators may penalize them for investments which fail to perform, they may act in an unduly risk-averse manner and just carry on doing what they have always done, particularly if new technologies are not as well understood as traditional ones; and, at least in the short term, choice of technologies may be affected by limitations in the supply chain for HVDC equipment, and in particular cables, while traditional HVAC infrastructure is more readily available.

Everyone would agree that regulators should protect customers' interests. However, they also need to realize that, in a world of technical change, this sometimes means innovation and taking greater risks. While penalizing failure (e.g., lower asset availability) or failing to allow companies to pay to reserve supply chain capacity may feel like the right strategy in the short term, this could act to stall innovation, which in turn might be against customers' long-term interests. Striking the right balance is therefore critical.

The NeuConnect project (discussed in the next part of this article) provides a good illustration of how regulators such as Ofgem have taken a flexible approach in adapting regulatory regimes to unlock private investment in HVDC infrastructure through revenue support arrangements.

PART 2 – STRUCTURING AND FINANCING HVDC TRANSMISSION LINE PROJECTS

As discussed above, there is likely to be significant future increased demand for low loss, long-distance interconnectors. While the concept of transmitting large amounts of energy with relatively low losses over long distances (e.g., from solar farms in North Africa to Europe) might be attractive in principle, significant political, economic and legal challenges face potential investors and lenders, particularly in developing jurisdictions.

This part of the article explores the key models for structuring and financing transmission infrastructure, including the integrated grid model, merchant investment and independent power transmission (IPT) projects.

INTEGRATED GRID MODEL

Power transmission has traditionally been considered a natural monopoly. Globally, transmission assets are most commonly owned and/or operated by a transmission utility as part of an integrated grid. The transmission utility may be state-owned, privately owned or operating under a concession granted by the government. Under this model, investment in transmission lines is typically financed using the utility's balance sheet and recovered through a regulated tariff. This tariff is charged to consumers as part of the overall retail electricity price. However, in countries where the transmission infrastructure is publicly owned, this model can strain public finances, particularly when governments and state-owned utilities face fiscal constraints. This often results in underinvestment in transmission infrastructure and delays to necessary upgrades.

MERCHANT INVESTMENT

The merchant investment model is a privately funded approach to developing transmission lines where revenue is primarily derived from price differentials between two markets or zones creating arbitrage opportunities. This makes it particularly suited for cross-border interconnections or countries with an unbundled power market and multiple wholesale price zones. Many interconnection projects[6] to date have used the merchant investment model in which the investor builds and operates a transmission line. This model is typically for standalone assets – either a single line or a bundle of lines. A technical requirement for the merchant model is the ability to control and measure electricity flows, as the operator profits from directing power where it is most valuable. As such, this model is more suited for DC lines.

However, the revenue uncertainty of this model makes it more difficult to finance using project finance techniques, which require predictable revenue streams. To mitigate this risk, governments have sometimes intervened to support merchant lines. One example is the NeuConnect interconnector between the UK and Germany, which operates under a cap and floor mechanism. This reduces revenue uncertainty, improving bankability while still allowing private investors to benefit from price differentials.

The merchant investment model is not generally viable in countries without liberalised wholesale electricity markets. This is the case for many emerging markets with a vertically integrated, state-owned power sector. The lack of a competitive wholesale market and transparent, market-based price signals limits the potential for price differentials and reduces opportunities for price arbitrage between different markets or zones that are essential for a merchant line's revenue model.

IPT PROJECTS

Another model which can facilitate private investment in transmission assets is independent power transmission (IPT). In essence, it involves the govern-

[6] Outside Europe, where interconnectors are subject to regulation unless they are formally exempted. Even in the latter case, conditions may be placed on the exemption, such as an overall IRR cap.

ment (or the state-owned utility) tendering a long-term contract whereby the IPT (the winning bidder) will be responsible for building and operating a transmission line in exchange for contractually defined payments dependent upon the availability of the line.

A recent example of an IPT project, although not HVDC, is the 400 kV Lessos-Loosuk and 220 kV Kisumu-Musaga transmission lines in Kenya. This project involves the development, financing and construction of the transmission lines under a public-private partnership framework by Africa50 and the Power Grid Corporation of India Limited. The project is set to become Kenya's first IPT and a pioneering example in Africa.

IPT projects have been adopted in many countries, albeit mostly for in-country transmission. Adopting the same model for international interconnectors is likely to be more complex, not least due to the need to coordinate between the governments of the relevant countries.

Also in the African context, the Côte d'Ivoire-Liberia-Sierra Leone-Guinea (CLSG) interconnection project, financed by the AfDB, EIB, KfW, World Bank and its member countries and completed and commissioned in 2021, illustrates one way forward. It involved the construction of a 1,300 km long 225 kV AC transmission line and associated substations connecting four participating countries' energy systems into the WAPP. The project was implemented through a regional special purpose company (Transco), jointly owned by the national utilities of those countries, and responsible for the financing, construction, ownership and operation of the project assets.

To encourage the use of the CLSG transmission line, an open access policy was adopted. Power purchase agreements (PPAs) were signed between Côte d'Ivoire's national utility and those of the other three countries, with each also entering into a transmission service agreement with Transco. The transmission tariff was set using the "postage-stamp" methodology rather than an availability-based tariff, so that transmission costs are effectively charged to the power purchasers based on their relative shares of trade through the transmission line. To mitigate the risk of a funding shortfall owing to low trading volumes, Transco's shareholders agreed to cover any shortfall from trading revenue. This pricing methodology ensures cost recovery whilst facilitating trade through the transmission line.

While the CLSG project structure does not involve any private investment, in principle a similar structure could be adopted to implement the IPT model; for example, by replacing government-owned shareholders of Transco with private sector sponsors.

To a limited extent this was the structure adopted by the Central American Electricity Interconnection System (SIEPAC) which was taken into account in structuring the CLSG project. The SIEPAC transmission company (EPR),owns the 1,793 km interconnector (230 kV) linking the power grids of six Central American countries. EPR is owned by eight national utilities or transmission companies together with a private company (ENDESA of Spain) which is responsible for managing EPR. During the project design stage, the option of relying entirely on private investment was considered, but it was ultimately decided that there might not be sufficient interest from the private sector due to perceived project risks and the natural monopoly nature of transmission. Nevertheless, there seems to be no reason why, through proper risk management and with adequate financial incentives, such a structure could not be adopted with entirely private ownership.

REGULATORY AND LEGAL CHALLENGES

In many developing countries, the electricity sector remains vertically integrated with monopoly networks. Although full "unbundling" is not a necessary pre-condition for IPT projects, existing legislation and regulation will need to be reviewed and may need to be revised to enable an IPT project to operate alongside the national utility. In particular, the grid code will likely need to be modified to include operating procedures and principles. In the context of an interconnection project, this will need to be done for each country to which it connects and could be cumbersome and result in a long development period.

This challenge was highlighted by the North Core Interconnector Project (a 330 kV AC transmission line connecting Nigeria, Niger, Benin and Burkina Faso). According to the ECOWAS Master Plan, the SPV structure adopted in the CLSG project was originally considered for the North Core project but was ultimately not adopted owing to concerns over the delay that could be caused by the need to make adjustments to national legal frameworks.

In civil law jurisdictions, specific enabling legislation may also be required to implement interconnector projects. Conflicts of law and policy questions may also arise where cross-border agreements are entered into; for example, some provisions of law may have mandatory application in certain jurisdictions; and where state-owned entities are involved, legal or policy requirements may dictate a choice of a particular governing law or dispute resolution arrangement.

"PROJECT-ON-PROJECT" RISK

For a cross-border interconnector, separate SPVs (or sub-projects) may be established in each relevant jurisdiction. This approach offers several benefits, including ring-fencing national risks, aligning with local licensing requirements and facilitating construction delivery management. However, it also introduces a high degree of interdependency, as each project segment must be successfully completed for the overall project to function. This creates challenges in managing interface risks, project delivery alignment and providing certainty for stakeholders in each sub-project that the other sub-project(s) will be delivered as planned.

To address these risks, risk allocation between project sponsors and other contract parties must be carefully calibrated to ensure that risk levels are acceptable to all stakeholders while achieving the bankability of the project.

FINANCIAL VIABILITY

The CLSG project provided an example of how transmission tariffs can be set to meet minimum revenue requirements. Investors, however, need confidence that contractual payments will be received from the transmission line users, which are likely to be national utilities, who may be in poor financial health. Many developing countries have experience in addressing this question in the context of independent power projects (IPPs), which may provide valuable lessons for developing IPT projects. For example, credit support may be provided through the use of escrow accounts to prioritize payments to private sector market participants. Where this is insufficient, governments may provide sovereign guarantees (or other government support) for payment obligations to IPTs. Additional security may also be provided by development finance institutions (DFIs).

EPC CONTRACT QUESTIONS

The structuring of an interconnector project may present challenges in negotiating an EPC contract. For example, where multiple procuring parties decide to use a single entity (e.g., a special purpose vehicle company) to act as the employer under an EPC contract, with assets transferred to them as third party owners, particular concerns may arise for both the procuring parties and the contractor under the EPC contract, including in respect of risk allocation, indemnities, insurance and ensuring that the asset owners obtain the full benefit of rights under the EPC contract whilst the EPC contractor maintains adequate recourse against parties of sufficient financial substance; and bespoke amendments are likely to be required to standard construction contracts, e.g., those based on FIDIC forms.

THE EUROPEAN INTERCONNECTOR EXPERIENCE AND PROJECT REVENUE SUPPORT REGIMES

The European market offers examples of successful privately financed submarine HVDC interconnector projects, underpinned by revenue support arrangements to make investment sufficiently attractive to sponsors and risks more palatable to prospective lenders.

The NeuConnect interconnector will create the first direct power link between Germany and the UK, two of Europe's largest energy markets, and allowing trading of electricity between them. Construction of the pair of 725 km long terrestrial and subsea 525 kV HVDC cables is in progress and will create 1.4 GW of transmission bi-directional transmission capacity, sufficient to power 1.5 million homes.

The project has a capital cost of around £2.4 billion and achieved financial close in 2022, involving Meridiam, Allianz Capital Partners, Kansai Electric Power Grid and TEPCO Power Grid as sponsors and a consortium of more than 20 major banks and financial institutions as lenders (including EIB and JBIC). NeuConnect Britain Ltd. (NBL), incorporated in England, is responsible for all aspects of the project in the UK (as well as construction works in Dutch waters) while NeuConnect Deutschland GmbH & Co. KG, incorporated in Germany, is responsible for all aspects of the project in Germany.

NeuConnect states that it will facilitate non-discriminatory, fair and transparent access to capacity through a range of standardized auctioned products, detailed in Access Rules which are compliant with relevant regulations. The project however takes limited merchant risk as its revenues are underpinned by a 25-year cap and floor regime in the UK, which broadly covers 50% of project costs and 50% of the total revenues earned by the interconnector. Under this scheme, the project is entitled to a minimum revenue (the notional floor) but in return agrees to a defined cap above which all revenues will in effect be paid back to the electricity consumers. This mechanism is intended to ensure that end-consumers obtain value for money by capping investment returns if the project outperforms revenue expectations in exchange for the protection granted through the floor, with an element of commercial risk for the project in between, thereby providing an incentive for private investors to develop interconnector projects, as compared with other regimes where revenues are purely regulated and return on equity is generally insufficiently attractive.

Ofgem approved regulatory changes to the pre-existing UK cap and floor regime to allow the project to go ahead. Meanwhile, in Germany, legislative change was needed to accommodate the project. Pre-existing German legislation (the EnWG law) did not cover interconnector assets that were not owned by a German TSO, requiring an amendment to extend the German StromNEV regime to NeuConnect. Under this regime, the project receives statutory revenues based on its assessed cost base, including depreciation of the RAB and return on such RAB (differentiated between equity and debt). NeuConnect receives its regulatory revenues from TenneT TSO GmbH, the local transmission system operator in northern Germany.

In both jurisdictions, it is understood that the revenue support arrangements are adjusted based on the level of availability of the interconnector in order to incentivize the project to maximize availability.

THREATS

Recent geopolitical events have highlighted the vulnerability of subsea data cables, gas pipelines and submarine electricity cables to deliberate sabotage or damage from ships' anchors. It seems unlikely that insurance will be available for such risks and unless governments are willing to underwrite remediation costs and lost revenues, future private investment in submarine HVDC cables may be thrown into doubt in vulnerable areas of the world.

CONCLUSIONS

While AC power transmission and distribution systems are likely to remain for many years to come and may never be entirely replaced, HVDC is certain to play a vital role in providing backbone infrastructure to support a low carbon future. Investors, lenders, utilities, regulators and policymakers alike will be taking a keen interest in this exciting technology.